Ameren

P.O. Box 66149
St. Louis, Missouri
63166-6149
www.Ameren.com

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Ameren 2002 Annual Report

Ameren Delivers...

2002 Annual Report

Ameren

Ameren Delivers...

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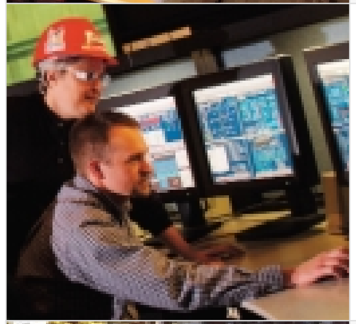
Ameren Delivers...
Core Business Growth

Ameren has grown through economic development in our service area and the recent acquisition of CILCORP. Expected to be accretive to earnings in 2003, this transaction brings Ameren's total customers to 2.2 million. AmerenCILCO also brings a geographically contiguous territory to Ameren, diversifying the company's revenue sources, expanding the scale and reach of its utility business and providing synergies. Read more about Ameren's core business growth strategy.



Ameren Delivers...
Operational Excellence

With generating capacity of 14,500 megawatts, Ameren continues to increase plant availability and reduce costs by installing control technology and increasing fuel transportation options. In 2002, Ameren's plants set a number of generating records, including a world record at Sioux Plant for continuous generation. In addition to their strong performance, Ameren plants still rank among the nation's cleanest. Find out more about Ameren's focus on operational excellence.

Ameren Delivers...
Superior Service

Ameren's 2.2 million customers demand superior service. Automated metering technology and integrated outage reporting systems help reduce outage frequency and speed recovery time. In addition to voice response systems offering up-to-the minute information on services and outages, Ameren is adding internet-based services that customers can use for most routine transactions. Learn more about Ameren's highly rated customer service.

Core Business Growth
- Building upon a strong regional position with strategic acquisitions
- Encouraging growth in service areas
- Optimizing assets for a dedicated customer base

Operational Excellence
- Investing in infrastructure to continually improve operational efficiency and provide secure, efficient generation supply
- Reducing emissions
- Operating safely

Superior Service
- Employing technology to increase service responsiveness
- Ensuring greater reliability through system enhancements
- Offering low rates and high quality products

Value to Shareholders
- Maintaining financial strength and flexibility
- Providing high earnings quality and visibility
- Generating solid total returns with a consistent strategic focus

Ameren welcomes Peoria and AmerenCILCO.

FINANCIAL HIGHLIGHTS

Ameren Consolidated (In Millions, Except Per Share Amounts)	Year Ended December 31, 2002	Current Year Change
Earnings per Common Share[(a)]	$3.01	(13%)
Net Income[(a)]	$440	(8%)
Book Value per Common Share	$24.94	3%
Property and Plant (net)	$8,914	6%
Total Operating Revenues	$3,841	–
Native Kilowatthour Sales	55,586	5%
Total Kilowatthour Sales	70,339	2%
Dividends Paid per Common Share	$2.54	–

(a) excluding unusual charges of $58 million, net of taxes (40 cents per share). Charges included workforce reductions and suspension of operations or closure of units at two power plants as described in Note 9 of the Consolidated Financial Statements.

On Our Promises

(Left)
Gary L. Rainwater
President and
Chief Operating Officer

(Right)
Charles W. Mueller
Chairman and
Chief Executive Officer

AND WE ARE CONFIDENT WE WILL CONTINUE TO DELIVER ON THOSE PROMISES

- Delivering on Our Promises
- Delivering Financial Strength and Flexibility
- Delivering Regulatory Certainty
- Delivering Superior Service and Operational Excellence
- Delivering Growth in Our Core Energy Business

Delivering on Our Promises

Over the years, we have made promises to you – our owners. We have promised performance leadership by pursuing a consistent, long-term strategy that is focused on the core business of producing and delivering energy. We have committed to manage our business based on the core values of integrity, respect, stewardship, teamwork and commitment. We have committed to be a reliable energy provider that is focused on superior customer service. And we have promised to grow our business in a financially responsible manner and deliver solid returns to our investors.

Companies are often judged by how well they deliver on their promises. As we look back at 2002, many companies simply failed to deliver on their promises as they grappled with corporate governance issues and highly leveraged balance sheets. A weak economy and soft energy markets also negatively affected the energy sector. These factors ultimately led to one of the worst years for our industry since the Great Depression, according to Standard & Poor's – one of the nation's leading credit rating agencies.

At Ameren, we are proud to say that in 2002 we continued to deliver on our promises despite the many challenges our industry faced. As a result, our stock price outperformed major indices in 2002. When coupled with a dividend that yielded over 6 percent and our strong balance sheet, this performance provided our investors with continued strong overall returns, as the chart on page 3 shows.

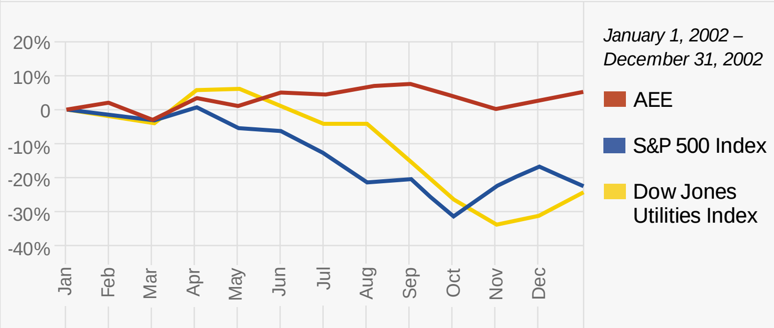
Delivering Financial Strength and Flexibility

A commitment to financial strength and flexibility has been a hallmark of our company for the past 100 years. This commitment has allowed our company to prosper during strong economic periods, and has allowed us to stay focused on our long-term strategic initiatives. During 2002 and early 2003, we have been very active in the capital markets as we proactively strengthened our balance sheet through the issuance of approximately 23 million shares of common stock, providing the funds required for the acquisition of CILCORP and for general corporate purposes. We enjoy some of the strongest credit ratings in the industry and at Dec. 31, 2002, had committed bank lines of credit of nearly $1 billion.

Delivering Regulatory Certainty

During 2002, we also ended a period of regulatory uncertainty with the settlement of the largest rate case in our history. In 2001, the Missouri Public Service Commission staff and other parties recommended electric revenue reductions of more than $300 million per year. In July 2002, we and all other parties in the case agreed to a settlement that was unanimously approved by the commission. It includes a rate moratorium through June 30, 2006, the phase-in of $110 million in electric rate reductions, and a commitment to energy conservation and assistance programs and critical energy infrastructure improvements. The rate moratorium in Missouri, coupled with a rate freeze in Illinois, provides a stable regulatory environment and greater clarity and certainty around the company's cash flows through 2006.

TOTAL INVESTOR RETURN



Ameren's return to investors outperformed major indices in 2002.

Delivering Superior Service and Operational Excellence

A major component of our success stems from delivering excellent customer service and achieving operational excellence. As a result of our investment in technology and our commitment to high service standards, Ameren ranks among the most highly rated utilities in the nation, according to the University of Michigan's American Customer Satisfaction Index. In addition, one of our Illinois utility companies – AmerenCIPS – held the highest rankings in almost every category in a recent statewide survey on service reliability.

Our commitment to improving the environment also brought recognition to Ameren in 2002. Generating units at AmerenUE's Labadie and Rush Island Power Plants earned top spots among U.S. coal-fired generating facilities as six of the nation's 10 lowest emitters of nitrogen oxide among more than 1,000 units. This is the fourth consecutive year those plants have earned top spots in an annual U.S. Environmental Protection Agency report. The report also ranked AmerenEnergy Generating's Newton Power Plant units 19th and 20th among the nation's lowest nitrogen oxide emitters. In addition, AmerenUE's Callaway Plant completed its 12th refueling outage with safety results that were among the best achieved in Callaway's history and that exceeded the high standards of the nuclear industry.

Delivering Growth in Our Core Energy Business

By pursuing growth in the areas where we excel – producing and delivering energy – we have been able to not only survive in the face of uncertainty, but to capitalize on opportunities as they arise. Our purchase of Peoria, Ill.-based CILCORP Inc. represents one of those opportunities. This $1.4 billion transaction, completed in early 2003, added 1,200 megawatts of largely low-cost, baseload coal generation, approximately 200,000 electric customers and 200,000 natural gas customers to our system.

We know this business and this market and expect this transaction to be immediately accretive to earnings. We approached the transaction conservatively, and given our track record in realizing savings from integrating operations, we expect to achieve synergies quickly. We remain focused on growing our core energy business so that we can continue to deliver strong total returns to our investors.

Sadly, the year also marked the death of Thomas H. Jacobsen, who since 1990 served as a member and/or advisor to the boards of both Ameren and Union Electric Company. Mr. Jacobsen was former chairman of Firstar Corporation. His consistently strong counsel will be missed.

We are proud of the accomplishments of 2002. We have improved our financial strength and increased operating efficiencies, settled the largest rate case in our history, won high marks for our customer service and environmental stewardship, and realized growth through our acquisition of CILCORP. However, going forward, we realize, we cannot rest on past achievements.

We recognize that 2003 presents significant challenges for Ameren and our industry as we expect soft energy market and economic conditions to persist. We also expect to contend with rising employee benefit, insurance and security costs.

We will continue to take prudent steps to benefit future operations. In 2002, approximately 550 employees accepted a voluntary retirement program offer, reducing total staffing and cutting our future labor costs. We established a freeze on management wage increases for 2003 and took steps to reduce employee and retiree medical benefit costs to realize future savings. We are also reducing capital expenditures in 2003 by nearly 16 percent from our original plans and have retired or suspended operations at some of our older, higher-cost generating units.

We expect these actions to position our company to continue to deliver solid long-term returns as the economy and energy markets recover. Our financial strength and flexibility allow us to employ these long-term action plans. We remain committed to efficiently producing and delivering reliable energy, maintaining our financial strength and flexibility and providing solid, long-term returns to our shareholders.

We want to thank you for your support and our employees for incorporating our values in everything they do. By adhering to these principles, we are confident we will continue to deliver on the promises Ameren has made to you.

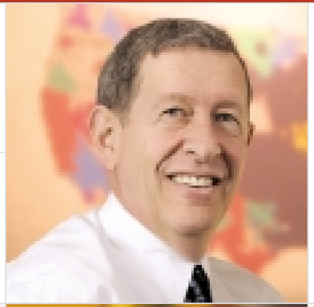
Chairman and Chief Executive Officer

President and Chief Operating Officer

CILCORP added 1,200 megawatts of largely low-cost, baseload coal generation, approximately 200,000 electric customers and 200,000 natural gas customers to our system.

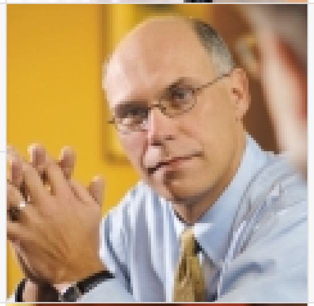
Senior Management Depth

Paul A. Agathen
Senior Vice President



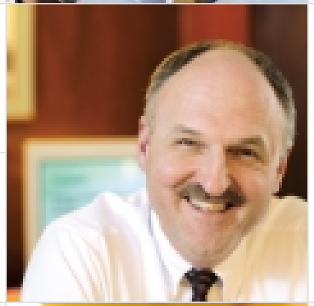
Paul A. Agathen was named senior vice president in 1996. He leads government and environmental affairs and also has responsibility for Corporate Communications and Public Policy, Human Resources, Information Technology and Environmental Services and Safety and Health. He joined the company in 1975 as an attorney after graduating cum laude from Saint Louis University Law School. He holds a master's degree in Business Administration and a bachelor's degree in Economics – both from the University of Missouri.

Warner L. Baxter
Senior Vice President, Finance



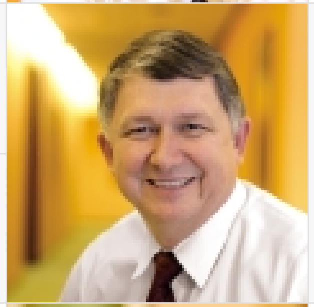
Warner L. Baxter has been senior vice president, Finance, since 2001, after joining the company in 1995 as assistant controller and later being named vice president and controller. As Ameren's chief financial officer, he led the development and implementation of several strategic initiatives, including Ameren's response to the 2002 Missouri retail electric rate case and negotiations involved in the CILCORP acquisition. Before joining Ameren, Baxter served as senior manager at a leading public accounting firm in St. Louis and New York City.

Daniel F. Cole
President, AmerenEnergy, Inc. and AmerenEnergy Resources



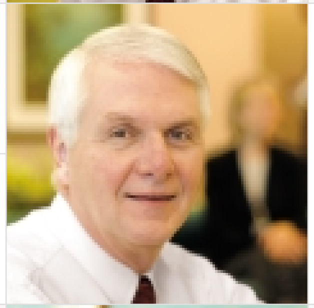
Daniel F. Cole is president of AmerenEnergy, Inc. (our short-term energy marketing company); and AmerenEnergy Resources Company, parent of AmerenEnergy Generating Company (our non-regulated generating subsidiary); AmerenEnergy Marketing (our long-term energy marketing organization); and AmerenEnergy Fuels and Services (our fuels management organization). He assumed his present title in 2001, after serving as senior vice president since 1999, and as vice president of Corporate Planning from 1998 to 1999. He joined the company in 1976 as an engineer.

Garry L. Randolph
Senior Vice President, Generation and Chief Nuclear Officer



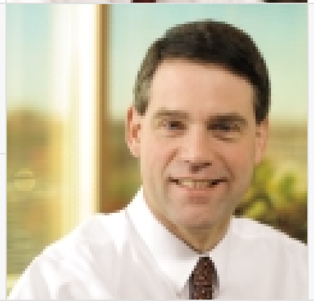
Garry L. Randolph was appointed senior vice president generation and chief nuclear officer in 2000, after serving at Callaway Plant since shortly after construction began. He assumed responsibility for all AmerenUE generation in 2001. He joined the company in 1977 and during his career has served in a number of senior leadership positions with the Nuclear Energy Institute and the Institute of Nuclear Power Operations, where he is now a member of the board of directors.

Thomas R. Voss
Senior Vice President, Energy Delivery



Thomas R. Voss has served as senior vice president for Energy Delivery since 1999 and is charged with leading all regulated utility delivery and customer service operations. He joined the company in 1969 as an engineer and has been responsible for establishing an automated metering system across our Missouri territory. He has also managed systemwide metering, forestry and dispatching and was instrumental in introducing state-of-the-art outage analysis, supervisory control and data acquisition systems at the company.

David A. Whiteley
Senior Vice President



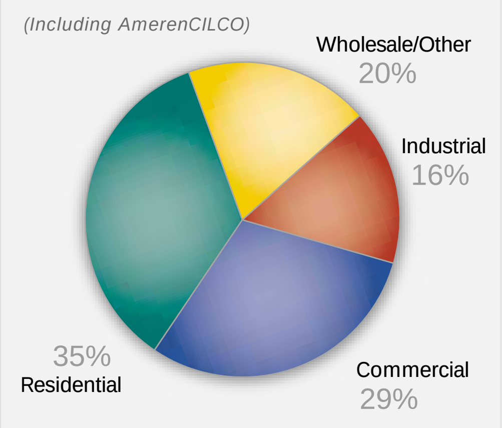
David A. Whiteley was named senior vice president in 2001. His area of responsibility includes management of our transmission policy and the company's strategic planning in addition to other support services for the corporation. He joined the company in 1978 as an engineer. He serves as the lead negotiator and representative in discussing with other parties and federal regulators the company's entry into, and operation within, a regional transmission organization.

Financial Overview

FINANCIAL DATA

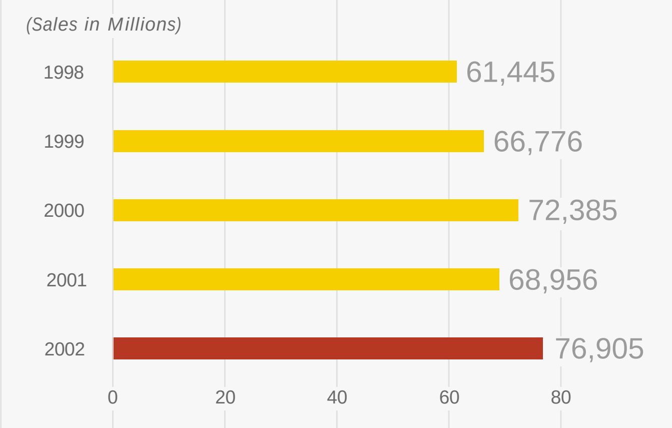
Key Data (2002)	Ameren	AmerenCILCO	Combined	Increase
Electric Customers	1,500,000	200,000	1,700,000	13%
Gas Customers	300,000	200,000	500,000	67%
Percent of Customers in Illinois	29%	100%	41%	12%
Generating Capacity	13,300 MW	1,200 MW	14,500 MW	9%
Electric System Miles	48,000	8,500	56,500	18%
Total Assets	$11.5 billion	$1.9 billion	$13.4 billion	17%
Total Operating Revenues	$3,841 million	$782 million	$4,623 million	20%

ELECTRIC REVENUE MIX



Ameren's diverse revenue mix offers more stable and predictable revenues than is the case for companies with revenues concentrated in only one or two customer segments.

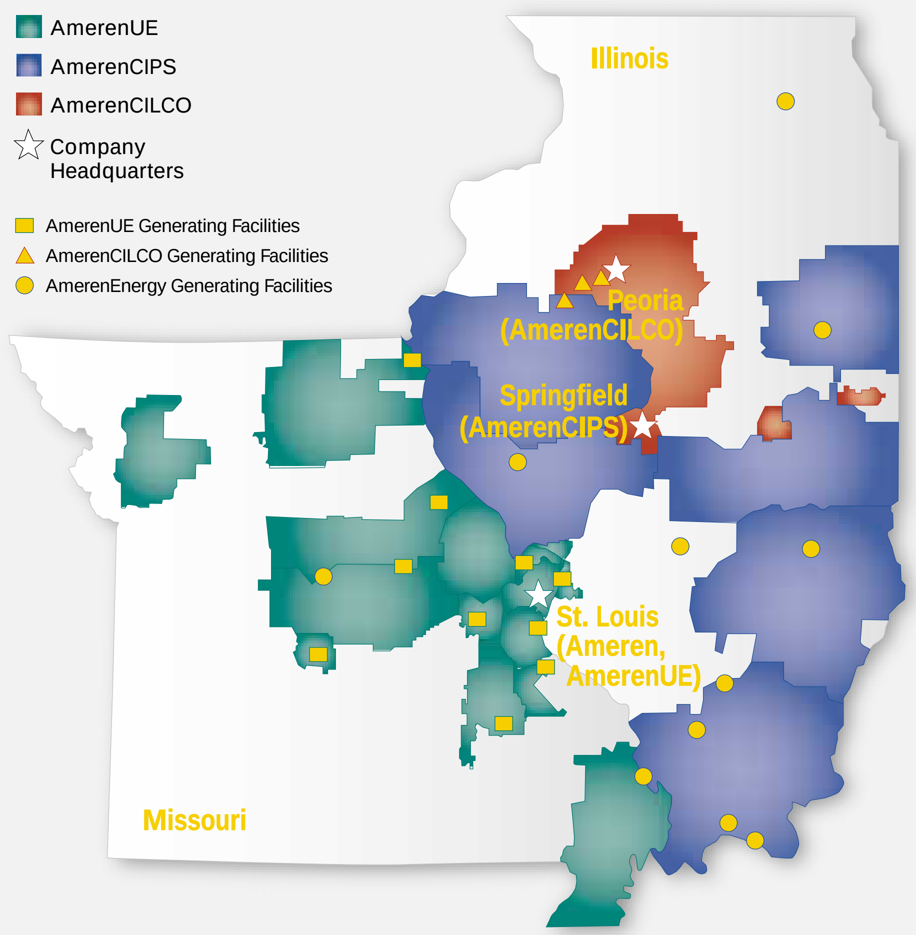
TOTAL KILOWATTHOUR SALES



Kilowatthour Sales with AmerenCILCO

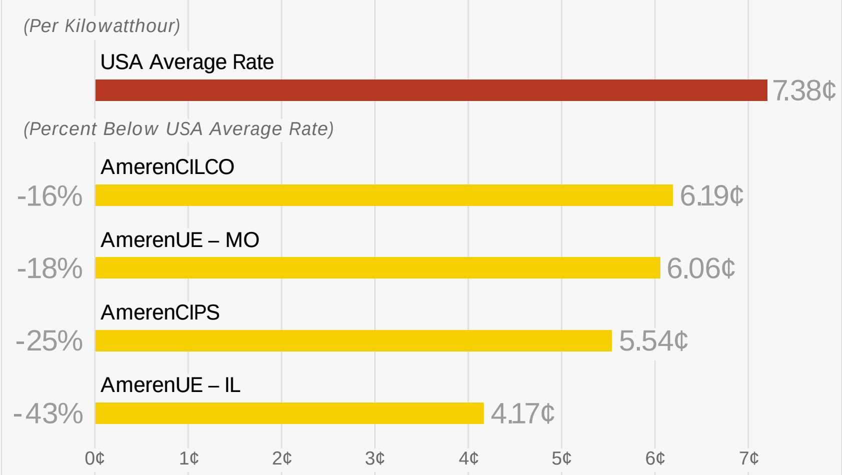
Kilowatthour sales reflect energy sold to other energy providers, businesses and institutions and residential customers – in effect, all the kilowatthours sold by Ameren companies.

AMEREN CORPORATION ELECTRIC AND GAS UTILITY COMPANIES



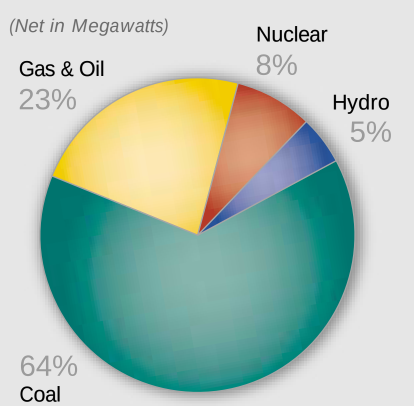
$800 million in revenue to come from AmerenCILCO

COMPETITIVE ELECTRIC RATES



Ameren's operating companies' annual average revenue per kilowatthour at June 30, 2002, was consistently below the national average revenue per kilowatthour over the same period. These low average rates mean that, in total, Ameren companies' average rates were nearly 20 percent below the national average.

FUEL DIVERSITY



Includes the generating capacity gained through the CILCORP acquisition

While Ameren is the 5th largest coal buyer in the nation, the company strives for diversity in fuel sources, as this chart illustrates.

Core Business Growth

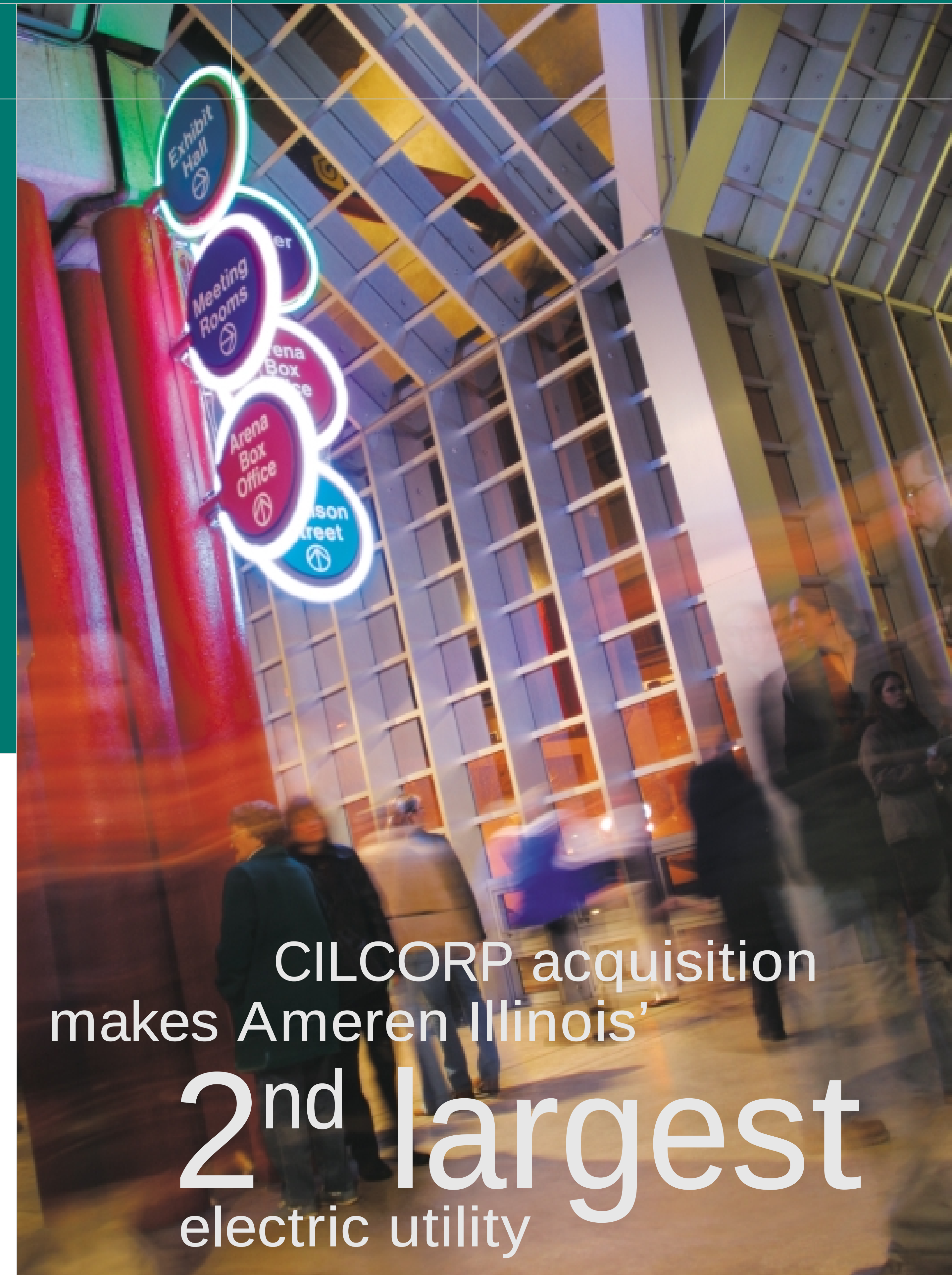
AMEREN POWERS MASTERCARD'S GLOBAL TECHNOLOGY AND OPERATIONS CENTER IN MISSOURI

- Building upon a strong regional position with strategic acquisitions
- Encouraging growth in service areas
- Optimizing assets for a dedicated customer base

"Together we successfully developed the 144-megawatt Columbia Energy Center. AmerenEnergy Generating owns and operates this peaking plant, while the city purchases part of the capacity. With this center, we can ensure our summertime reserve power, while Ameren earns fees for developing the project and selling its energy. Everybody benefits."

Dick Malon, director,
Columbia Water and Light Department
City of Columbia, Mo.

Success in the energy industry relies on size and strength built through targeted acquisitions and a resilient regional economy. From developing generation (left) to expanding our Illinois franchise, Ameren has focused on strategically managed growth. Above, MasterCard International employees conduct a planning session at their company's new O'Fallon, Mo., operations center. MasterCard is one of many companies to come to WingHaven – a 1,200-acre, mixed-use development AmerenUE supported through responsive service and technical advice. In Illinois, the addition of CILCORP made Ameren the state's second largest electric utility. AmerenCILCO's headquarters are in the second-largest city in Illinois – Peoria – where CILCO has been an active community leader for decades. Extensive riverfront development is adding vitality to downtown Peoria, where a new civic center (right) and a planned technology center have spurred economic growth.



Operational Excellence

ARRAY OF RUSH ISLAND COMPUTERS TRACK PERFORMANCE

- Investing in infrastructure to continually improve operational efficiency and provide secure, efficient generation supply
- Reducing emissions
- Operating safely

Ameren's operations demonstrated innovation and resourcefulness in achieving productivity gains in 2002. With a well-diversified fuel mix, the company can rely on low-cost, baseload generation, using gas- and oil-fired peaking generation when it is economical and to meet reserve margins. Ameren's baseload plants continue to reduce emissions and improve efficiency through effective deployment of technology: At the Rush Island Plant in Jefferson County, Mo., newly installed automated systems help Instrument and Control Supervisor Janice Aucutt and Assistant Unit Operating Engineer Steve Roesch precisely track unit performance – offering alarms to alert operators to any problems. Not only has this system streamlined operations, but newly automated log books allow planners to determine plant conditions and generate the necessary work orders. And through sophisticated data integration systems, plant staffs can analyze real-time energy market pricing to determine the best timing for planned outages and other activities.

In addition to a record year for summer generation availability established by all AmerenEnergy Generating nonregulated plants, Coffeen Plant set a peak generation record in July 2002. The Illinois-based plant moved to better control nitrogen oxide emissions by installing leading edge technology – a selective catalytic reduction system Shift Supervisor Terry Olroyd (above) helped install. This installation continues a strong tradition of environmental stewardship practiced by Ameren operations across Missouri and Illinois.

Superior Service

AMEREN EXPANDS INTERNET-BASED SERVICES

- Employing technology to increase service responsiveness
- Ensuring greater reliability through system enhancements
- Offering low rates and high quality products

These Ameren employees represent the dozens of employees who successfully upgraded customer systems across Illinois and Missouri, greatly increasing the information available to customer service representatives and the accuracy of account data. The team of computer experts and experienced customer service pros behind the account conversion included Customer Service Information System Business and Development Customer Service analysts, from left, Sung Chung, Terri Storie, Amy Kammien, Chris Eisele, JoAnn Hunt and Wesley Thomas.

Whether replacing cast iron gas lines with safer, more durable lines or upgrading customer information systems, Ameren continues to provide top-quality service at rates that are among the lowest in the nation. At right, AmerenUE Gas Mechanic John Hobbs talks to Alton resident Howell L. Sumner, who is one of 7,000 gas customers to get new highly resilient polyethylene piping. Above, a customer checks on his bill by going online. Now, AmerenUE and AmerenCIPS customers can turn on and turn off their service, view and change account data and handle more routine transactions – all online at www.Ameren.com. And Ameren's Energy Delivery organization continues to do what it has always done well – deliver energy reliably and partner with customers to solve energy problems. This focus on service excellence has earned the company top ratings in polls conducted both on the state and national levels.

Value to Shareholders

AND MAINTAINS FINANCIAL STRENGTH AND FLEXIBILITY

While the financial markets were shaken in 2002 by a weak economy and an erosion of investor confidence, our company continued to manage its financial resources to ensure financial stability and flexibility. The company's return to investors, relative to the market, reflected the results of this strategy. Ameren's Senior Vice President of Finance, Warner Baxter, reflects here about Ameren's overall financial strategy and addresses timely financial questions from investors.

Warner L. Baxter
Senior Vice President,
Finance

What is Ameren's strategy for managing its financial resources?

Simply put, our strategy is to maintain financial strength and flexibility so that we can operate the business for the long-term benefit of all of our stakeholders. We accomplish this by actively managing our cash flows and the balance of our outstanding debt and equity in order to maintain strong investment grade credit ratings. This strategy also requires us to effectively anticipate our financing requirements and proactively access the capital markets on favorable terms. Our debt and equity financings in 2002 and early 2003 are a good example of this strategy. In the end, this strategy permits us to weather tough economic and market conditions, make necessary energy infrastructure investments and pursue opportunistic growth in our core energy business, such as the acquisition of CILCORP.

Much has been written nationally about the lack of transparency in earnings and the need to restore investor confidence through reform of corporate governance. What has Ameren done to address these concerns?

At Ameren, we have always strived to live up to our core values and provide investors accurate and understandable information about our business. We don't have any investments, assets or financings that are carried off our balance sheet or speculative merchant trading operations. In addition, we haven't strayed from our core business – producing and delivering energy in markets we know. We haven't invested in overseas ventures or strayed outside our Midwest market. In fact, nearly 95 percent of our net earnings come from regulated operations. All this adds up to our investors' being able to understand how we make our money.

We also have a strong reputation for integrity and ethical conduct. However, we are always looking for ways to improve. Here are some of the measures we've employed recently:

- *For several years, we have published a widely distributed corporate code of conduct, which is strictly enforced. We recently added protections for any employee who cites violations of that policy, giving those individuals direct, confidential access to the chairman of the board's auditing committee.*
- *For many years, the independent directors you elected have provided a depth of business experience, and these directors have no interlocking directorships. The board's only current management employee is Ameren's CEO.*
- *The board's auditing, human resources (compensation) and nominating committees include only outside directors.*
- *We also renamed the board nominating committee, calling it the Nominating and Corporate Governance Committee, and expanded its responsibilities in the area of corporate governance.*
- *We established a strict, written policy limiting the use of external auditors primarily to auditing or audit-related services.*
- *We established an internal disclosure committee composed of financial, legal, and operating personnel to ensure that all material information is fully disclosed in our Securities and Exchange Commission filings.*

As these actions show, we are fully committed to implementing all applicable requirements of the recently enacted federal legislation, known as the Sarbanes-Oxley Act of 2002, and all other new regulatory rules.

You have an energy trading operation. Trading operations at many energy companies performed very poorly in 2002, exposing those companies to significant risk. How did AmerenEnergy perform in 2002, and what provisions do you have in place to protect Ameren from trading losses?

Our short-term energy marketing operations conducted by AmerenEnergy are governed by strict risk management guidelines set by a risk management committee that I chair. Those guidelines restrict energy sales based on Ameren's ability to produce and deliver power, as well as take into account counterparty credit risk. We also employ seasoned financial managers to closely monitor marketing activities and ensure daily adherence to these guidelines.

Our energy marketing operations focus on optimizing our physical generation assets by capitalizing on sales opportunities. And while seeking to capitalize on these sales, these operations also provide defensive support, giving us quick access to energy markets if we have peaks in demand or unscheduled plant outages.

In 2002, AmerenEnergy contributed 20 cents per share to earnings, down from 23 cents in 2001. The decline was due primarily to lower wholesale energy prices and less low-cost excess generation available for sale due to the warm summer weather.

Many companies now have underfunded pension plans and face significant federally mandated funding requirements in the near future. What is Ameren's status in this area?

Pension obligations represent the estimated amount an employer would need to invest today to meet the projected obligations to retirees in the future. Just two years ago our pension obligations were fully funded, but with the poor stock market performance and low interest rates, our plans were underfunded by $528 million at Dec. 31, 2002.

In 2002, we proactively contributed $31 million to our pension plan trust. Consequently, we have no significant pension funding requirements until 2005.

Several companies in the energy sector cut their dividends in 2002. Ameren currently has a relatively high dividend payout ratio. Do you expect Ameren to reduce its dividend in 2003?

We recognize the importance of maintaining the dividend. Dividend policy is ultimately set by our board of directors. Several factors are considered in establishing this policy, including historic and projected earnings, future cash requirements, dividends at other utilities and overall business conditions. Historically, Ameren has always believed that the payment of dividends is a time-proven method of returning wealth to our shareholders. And while our payout ratio is expected to range between 80 and 90 percent in 2003, this, in and of itself, is not particularly troubling to our company. Investors may recall that our annual dividend payout was in excess of 90 percent from 1995 through 1999, and our cash flows today still come largely from stable, regulated operations.

Warner L. Baxter

Senior Vice President, Finance

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Ameren Corporation is responsible for the information and representations contained in the consolidated financial statements and in other sections of this Annual Report. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. Other information included in this report is consistent, where applicable, with the consolidated financial statements.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance as to the integrity of the financial records and the protection of assets. Qualified personnel are selected and an organization structure is maintained that provides for appropriate functional responsibility.

Written policies and procedures have been developed and are revised as necessary. The Company maintains and supports an extensive program of internal audits with appropriate management follow up.

The Board of Directors, through its Auditing Committee comprised of outside directors, is responsible for ensuring that both management and the independent accountants fulfill their respective responsibilities relative to the financial statements. Moreover, the independent accountants have full and free access to meet with the Auditing Committee, with or without management present, to discuss auditing or financial reporting matters.

Charles W. Mueller
Chairman and Chief Executive Officer
February 13, 2003

Warner L. Baxter
Senior Vice President, Finance
February 13, 2003

REPORT OF INDEPENDENT ACCOUNTANTS

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF AMEREN CORPORATION:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, common stockholders' equity and cash flows present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 2002, and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 13, 2003

OVERVIEW

Ameren Corporation is a public utility holding company registered under the Public Utility Holding Company Act of 1935 (PUHCA) and is headquartered in St. Louis, Missouri. Our principal business is the generation, transmission and distribution of electricity, and the distribution of natural gas to residential, commercial, industrial and wholesale users in the central United States. Our primary subsidiaries are as follows:

- Union Electric Company, which operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois as AmerenUE.
- Central Illinois Public Service Company, which operates a rate-regulated electric and natural gas transmission and distribution business in Illinois as AmerenCIPS.
- Central Illinois Light Company, a subsidiary of CILCORP Inc., which operates a rate-regulated transmission and distribution business, an electric generation business, and a rate-regulated natural gas distribution business in Illinois as AmerenCILCO. We completed our acquisition of CILCORP on January 31, 2003 from The AES Corporation (AES). See Recent Developments for further information.
- AmerenEnergy Resources Company (Resources Company), which consists of non rate-regulated operations. Subsidiaries include AmerenEnergy Generating Company (Generating Company) that operates non rate-regulated electric generation in Missouri and Illinois, AmerenEnergy Marketing Company (Marketing Company), which markets power for periods over one year, AmerenEnergy Fuels and Services Company, which procures fuel and manages the related risks for our affiliated companies and AmerenEnergy Medina Valley Cogen (No. 4), LLC which indirectly owns a 40 megawatt, gas-fired electric generation plant. On February 4, 2003, we completed our acquisition of AES Medina Valley Cogen (No. 4), LLC from AES and renamed it AmerenEnergy Medina Valley Cogen (No. 4), LLC. See Recent Developments for further information.
- AmerenEnergy, Inc. (AmerenEnergy) which serves as a power marketing and risk management agent for our affiliated companies for transactions of primarily less than one year.
- Electric Energy, Inc. (EEI), which operates electric generation and transmission facilities in Illinois. We have a 60% ownership interest in EEI and consolidate it for financial reporting purposes.
- Ameren Services Company, which provides shared support services to us and our subsidiaries.

When we refer to Ameren, our, we or us, we are referring to Ameren Corporation and its subsidiaries on a consolidated basis. In certain circumstances, our subsidiaries are specifically referenced in order to distinguish among their different business activities. The financial results of CILCORP have not been included or discussed in this report except with regard to certain forward looking information. All tabular dollar amounts are in millions, unless otherwise indicated.

Our results of operations and financial position are impacted by many factors, including both controllable and uncontrollable factors. Weather, economic conditions and the actions of key customers or competitors can significantly impact the demand for our services. Our results are also impacted by seasonal fluctuations caused by winter heating, and summer cooling, demand. With approximately 85% of our revenues directly subject to regulation by various state and federal agencies, decisions by regulators can have a material impact on the price we charge for our services. We principally utilize coal, nuclear fuel, natural gas and oil in our operations. The prices for these commodities can fluctuate significantly due to the world economic and political environment, weather, production levels and many other factors. We do not have fuel cost recovery mechanisms in Missouri or Illinois for our electric utility businesses, but we do have gas cost recovery mechanisms in each state for our gas utility businesses. In addition, our electric rates in Missouri and Illinois are largely set through 2006. We employ various risk management strategies in order to try to reduce our exposure to commodity risks and other risks inherent in our business. The reliability of our power plants, and transmission and distribution systems, and the level of operating and administrative costs, and capital investment are key factors that we seek to control in order to optimize our results of operations, cash flows and financial position.

RESULTS OF OPERATIONS

Earnings Summary

Our net income for 2002, 2001 and 2000, was $382 million ($2.61 per share before dilution), $469 million ($3.41 per share before dilution), and $457 million ($3.33 per share), respectively. Net income in 2002 included voluntary retirement and other restructuring charges (40 cents per share), which consisted of a voluntary retirement program, the retirement of our Venice, Illinois plant, and the temporary suspension of operation of two coal-fired generating units at our Meredosia, Illinois plant. In 2001, net income was reduced by the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (5 cents per share).

The following table reconciles our net income to net income excluding voluntary retirement and restructuring charges and SFAS 133 adoption for the years ended December 31, 2002, 2001, and 2000:

	2002	2001	2000
Net income	$ 382	$ 469	$ 457
Earnings per share – basic	*$2.61*	*$3.41*	*$3.33*
Voluntary retirement and other restructuring charges, net of taxes	58	–	–
SFAS 133 adoption, net of taxes	–	7	–
Cents per share	*$0.40*	*$0.05*	*$ –*
Net income excluding restructuring charges and SFAS 133 adoption	$ 440	$ 476	$ 457
Earnings per share, excluding restructuring charges and SFAS 133 adoption – basic	*$3.01*	*$3.46*	*$3.33*

Excluding the charges discussed above, our net income in 2002 decreased $36 million from 2001, primarily due to the impact of the settlement of our Missouri electric rate case (26 cents per share), increased costs of employee benefits (15 cents per share), higher depreciation (17 cents per share), excluding the effect of the rate case that is included in the 26 cents above, and a decline in industrial sales due to the continued soft economy. Increased average shares outstanding (8.8 million shares) and financing costs also reduced earnings per share in 2002 (29 cents per share). Factors decreasing net income in 2002 were partially offset by favorable weather conditions (24 cents per share), sales of emission credits by EEI (10 cents per share) and organic growth.

Excluding the charges discussed above, our net income in 2001 increased $19 million from 2000, primarily due to a reduction in estimated credits to Missouri customers (33 cents per share) and organic growth, partially offset by increased costs of employee benefits (13 cents per share), higher depreciation and interest expense, and a refueling outage at Callaway. There was not a refueling at Callaway in 2000.

As a holding company, our net income and cash flows are primarily generated by our principal operating subsidiaries, AmerenUE, AmerenCIPS and Generating Company. These subsidiaries also file quarterly and annual reports with the Securities and Exchange Commission (SEC). The contribution by our principal operating subsidiaries to net income for the years ended December 31, 2002, 2001, and 2000 were as follows:

	2002	2001	2000
Primarily rate-regulated operations:			
AmerenUE (a)	$336	$365	$344
AmerenCIPS (b)	23	42	75
	$359	$407	$419
Primarily non rate-regulated operations:			
Generating Company (a)(b)(c)	32	76	44
Other	(9)	(14)	(6)
Ameren net income	$382	$469	$457

(a) Includes earnings from interchange sales by AmerenEnergy that provided approximately $20 million of AmerenUE's net income and $10 million of Generating Company's net income in 2002.

(b) 2000 data represents the period from May 1, 2000 through December 31, 2000, which was Generating Company's initial eight months of operation. Prior to May 1, 2000, AmerenCIPS operated the generating facilities now operated by Generating Company.

(c) Includes earnings from contracts to supply power to our rate-regulated AmerenCIPS customers.

Recent Developments

CILCORP Acquisition

On January 31, 2003, after receipt of the necessary regulatory agency approvals and clearance from the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act, we completed our acquisition of all of the outstanding common stock of CILCORP Inc. from AES. CILCORP is the parent company of Peoria, Illinois-based Central Illinois Light Company, which operated as CILCO. With the acquisition, CILCO became an Ameren subsidiary, but remains a separate utility company, operating as AmerenCILCO. On February 4, 2003, we also completed our acquisition of AES Medina Valley Cogen (No. 4), LLC (Medina Valley) which indirectly owns a 40 megawatt, gas-fired electric generation plant. With the acquisition, Medina Valley became a wholly-owned subsidiary of Resources Company which we renamed AmerenEnergy Medina Valley Cogen (No. 4), LLC. The CILCORP and AmerenEnergy Medina Valley Cogen (No. 4), LLC financial statements will be included in our consolidated financial statements effective with the January and February 2003 acquisition dates.

We acquired CILCORP to complement our existing Illinois electric and gas operations. The purchase included CILCO's rate-regulated electric and natural gas businesses in Illinois serving approximately 200,000 and 205,000 customers, respectively, of which approximately 150,000 are combination electric and gas customers. CILCO's service territory is contiguous to our service territory. In addition, the purchase includes approximately 1,200 megawatts of largely coal-fired generating capacity, most of which is expected to become non rate-regulated in 2003.

The total purchase price was approximately $1.4 billion and included the assumption of CILCORP and Medina Valley debt and preferred stock at closing of approximately $900 million, with the balance of the purchase price of approximately $500 million paid with cash on hand. The purchase price is subject to certain adjustments for working capital and other changes pending the finalization of CILCORP's closing balance sheet. The cash component of the purchase price came from Ameren's issuances in September 2002 of 8.05 million common shares and in early 2003 of 6.325 million shares. See Common Stock Offering below.

Common Stock Offering

In early 2003, Ameren issued 6.325 million shares of common stock at $40.50 per share. We received net proceeds after fees of $248 million, which were used to fund a portion of the purchase price for our acquisition of CILCORP and for general corporate purposes.

Credit Ratings

In April 2002, as a result of AmerenUE's then pending Missouri electric earnings complaint case and the CILCORP transaction and related assumption of debt, credit rating agencies placed Ameren Corporation's and its subsidiaries' debt under review. Following the completion of the acquisition of CILCORP in January 2003, Standard & Poor's lowered the ratings of Ameren Corporation, AmerenUE and AmerenCIPS and increased the ratings of Generating Company. At the same time, Standard & Poor's changed the outlook assigned to all of Ameren's ratings to stable. Moody's also lowered Ameren Corporation's and AmerenUE's ratings subsequent to the acquisition and changed the outlook on these ratings to stable. These actions were consistent with the actions the rating agencies disclosed they were considering following the announcement of the CILCORP acquisition.

As of February 2003, the ratings by Moody's and Standard & Poor's were as follows:

	Moody's	Standard & Poor's
Ameren Corporation:		
Issuer/Corporate credit rating	A3	A-
Unsecured debt	A3	BBB+
Commercial paper	P-2	A-2
AmerenUE:		
Secured debt	A1	A-
Unsecured debt	A2	BBB+
Commercial paper	P-1	A-2
AmerenCIPS:		
Secured debt	A1	A-
Unsecured debt	A2	BBB+
Generating Company:		
Unsecured debt	A3/Baa2	A-

Standard & Poor's increased the ratings of CILCORP and CILCO subsequent to the acquisition of these entities by Ameren Corporation. As of February 2003, the unsecured debt ratings of CILCORP were BBB+ and Baa2 from Standard & Poor's and Moody's, respectively. The secured debt ratings of AmerenCILCO were A- and A2 from Standard & Poor's and Moody's, respectively. Standard & Poor's assigned stable outlooks to these ratings. Moody's also assigned a stable outlook to the ratings for CILCORP and AmerenCILCO.

Any adverse change in Ameren's ratings may reduce our access to capital and/or increase the costs of borrowings resulting in a negative impact on earnings. A credit rating is not a recommendation to buy, sell or hold securities and should be evaluated independently of any other rating. Ratings are subject to revision or withdrawal at any time by the assigning rating organization.

Electric Operations

The following table represents the favorable (unfavorable) impact on electric margin versus the prior periods for the years ended December 31, 2002 and 2001:

	2002	2001
Operating revenues:		
Effect of abnormal weather (estimate)	$ 82	$ 10
Growth and other (estimate)	22	118
2002 Missouri rate settlement	(47)	–
Credit to customers	(10)	75
Interchange revenues	(109)	(168)
EEI	75	(54)
Total variation in electric operating revenues	13	(19)
Fuel and purchased power:		
Fuel:		
Generation	(46)	19
Price	5	(28)
Generation efficiencies and other	1	6
Purchased power	174	69
EEI	(45)	45
Total variation in fuel and purchased power	89	111
Change in electric margin	$102	$ 92

Electric margin increased $102 million for the year ended December 31, 2002 compared to 2001. Increases in electric margin in 2002 were primarily attributable to more favorable weather conditions and increased sales of emission credits. Weather sensitive residential electric kilowatthour sales in 2002 increased 7% and commercial electric kilowatthour sales increased 2%. However, industrial sales were approximately 5% lower in 2002 as compared to 2001 due primarily to the impact of the soft economy. Revenues were also reduced by $47 million in 2002 due to the settlement of the Missouri electric rate case. Contribution to electric margin from EEI increased in 2002 principally due to EEI's sale of $38 million in emission credits, which is included in the overall $75 million increase in EEI revenues. The remaining EEI increase was due to increased sales to its principal customer, which also resulted in an increase in fuel and purchased power. Interchange revenues decreased due to lower energy prices and less low-cost generation available for sale, resulting primarily from increased demand for generation from native load customers. Fuel and purchased power were reduced in 2002 due primarily to lower energy prices, partially offset by increased fuel and purchase power costs due to increased kilowatthour sales and unscheduled coal plant outages. We expect that revenues will continue to be negatively affected by the settlement of the Missouri rate case reached in 2002, which requires the phase-in of $30 million of electric rate reductions effective April 1, 2003 and $30 million effective April 1, 2004. In addition, we expect power prices in the energy markets to remain generally soft, which will impact the margins we can generate by marketing our power into the interchange markets.

During 2002, we adopted the provisions of Emerging Issues Task Force (EITF) Issue 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," that required revenues and costs associated with certain energy contracts to be shown on a net basis in the income statement. Prior to adopting EITF 02-3 and the rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," our accounting practice was to present all settled energy purchase or sale contracts within our power risk management program, on a gross basis in Operating Revenues – Electric and in Operating Expenses – Fuel and Purchased Power. This meant that revenues were recorded for the notional amount of the power sale contracts with a corresponding charge to income for the costs of the energy that was generated, or for the notional amount of a purchased power contract. Upon adoption, EITF 02-3 requires that prior periods also be netted to conform to the current year presentation. Adoption of this EITF did not have any impact on operating or net income for any period or stockholders' equity. The operating revenues and costs netted for the year ended December 31, 2002 were $738 million (2001 - $648 million) which reduced interchange revenues and purchased power costs by equal amounts. SFAS 133 was adopted on January 1, 2001 and therefore, no netting was required for the year ended December 31, 2000.

Electric margin increased $92 million for the year ended December 31, 2001 compared to 2000, primarily due to a $75 million reduction in the estimated credits to Missouri electric customers. During the year ended December 31, 2001, we reduced the estimated credit previously recorded for the plan year ended June 30, 2001 by $10 million, compared to estimated credits of $65 million recorded in 2000. In addition, industrial sales rose 11% primarily due to a new electric service industrial contract that was effective August 2000. Our residential sales were comparable to the prior year while commercial sales rose 1%. These increases were partially offset by a 31% decrease in interchange sales and reduced EEI sales. The $111 million decrease in fuel and purchased power costs for 2001, compared to 2000, was primarily due to reduced interchange sales.

Gas Operations

Our gas margin decreased $3 million in 2002 as compared to 2001 with revenues decreasing by $27 million and costs decreasing by $24 million. The decrease in margin was primarily due to the timing of revenue recovery under purchased gas adjustment clauses and warmer winter weather early in 2002, partially offset by increased gas sales due to colder than normal temperatures in late 2002.

Gas margin in 2001 increased $6 million, compared to 2000, primarily due to higher gas costs recovered through purchased gas adjustment clauses, partially offset by lower total sales of 9% resulting from unusually warm winter weather.

Other Operating Expenses

Other Operations and Maintenance

Other operations and maintenance expenses increased $70 million in 2002 compared to 2001, primarily due to higher employee benefit costs ($35 million), related to increasing healthcare costs and the investment performance of employee benefit plans' assets, higher wages and higher plant maintenance expenses. See also Equity Price Risk below for a discussion of our expectations and plans regarding trends in employee benefit costs.

Other operations and maintenance expenses increased $58 million in 2001 compared to 2000, primarily due to higher employee benefit costs in 2001 ($29 million), resulting from increasing healthcare costs and the investment performance of employee benefit plans' assets, a refueling outage at Callaway in 2001 versus no refueling in 2000, and increased costs of professional services. In 2000, we recorded a $25 million charge to earnings related to our withdrawal from the Midwest Independent System Operator (Midwest ISO). The charge reduced earnings $15 million, net of taxes, or 11 cents per share. See Regulatory Matters.

Restructuring Charges

Voluntary retirement and other restructuring charges of $92 million in 2002 consisted primarily of a voluntary retirement program charge of $75 million based on voluntary retirements of approximately 550 employees. These costs consisted primarily of special termination benefits associated with our pension and post-retirement benefit plans. Most of the employees who voluntarily retired will leave Ameren by March 2003. In addition, in December 2002, we announced our plans to retire 343 megawatts of rate-regulated capacity at AmerenUE's Venice, Illinois plant and temporarily suspend operations of two coal-fired generating units (126 megawatts) at Generating Company's Meredosia, Illinois plant, which resulted in a total charge of approximately $17 million.

Depreciation and Amortization

Depreciation and amortization expenses increased $25 million in 2002 and $23 million in 2001 compared to the prior years. These net increases were primarily due to our investment in combustion turbine electric generating plants and coal-fired power plants. The increase in 2002 was partially offset by a reduction of depreciation rates ($15 million) based on an updated analysis of asset values, service lives and accumulated depreciation levels that was included in our 2002 Missouri electric rate case settlement.

Income Taxes

Income tax expense decreased $50 million in 2002, compared to 2001, primarily due to lower pretax income. Income tax expense for 2001 was comparable to 2000.

Other Taxes

Other taxes expense in 2002 was comparable to 2001. Other tax expense decreased $4 million in 2001, compared to 2000, primarily due to a decrease in gross receipts taxes related to our Illinois jurisdiction.

Other Income and Deductions

Other income and deductions (excluding income taxes) decreased $48 million in 2002, compared to the prior year. The decrease was primarily due to the cost of economic development and energy assistance programs included in the settlement of the Missouri electric rate case ($26 million) and an increase in the deduction for minority interest earnings principally related to EEI's sale of emission credits ($10 million). Other income and deductions (excluding income taxes) increased $21 million in 2001, compared to 2000, primarily due to contributions in aid of construction ($7 million), decreased charitable contributions, and life insurance proceeds. See Note 10 – Miscellaneous, Net to our Consolidated Financial Statements for further information.

Interest

Interest expense increased $20 million in 2002, compared to 2001 primarily due to the interest expense component associated with the $345 million of adjustable conversion rate equity security units we issued in March 2002 and Generating Company's issuance of $275 million of 7.95% notes in June 2002. Proceeds from these offerings were used to repay lower cost short-term borrowings and for general corporate purposes. Interest expense increased $19 million in 2001, compared to 2000, primarily due to increased debt related to the construction and purchase of combustion turbine generating facilities, partially offset by lower interest rates.

LIQUIDITY AND CAPITAL RESOURCES

Operating

Our cash flows provided by operating activities totaled $833 million for 2002, compared to $738 million for 2001, and $864 million for 2000. Cash provided from operations increased in 2002, primarily as a result of higher cash earnings resulting from favorable weather and the sale of emission credits. These increases were partially offset by payments of customer sharing credits under AmerenUE's now-expired electric alternative regulation plan ($40 million), discretionary pension plan contributions ($31 million) and the timing of payments on accounts payable and accrued taxes. Cash flow from operations decreased in 2001, principally due to the timing of credits provided to AmerenUE's Missouri electric customers and changes in working capital requirements, partially offset by increased earnings.

The tariff-based gross margins of our rate-regulated utility operating companies continue to be our principal source of cash from operating activities. Our diversified retail customer mix of primarily rate-regulated residential, commercial and industrial classes and a commodity mix of gas and electric service provide a reasonably predictable source of cash flows. In addition, we plan to utilize short-term debt to support normal operations and other temporary capital requirements.

Pension Funding

We made cash contributions totaling $31 million to our defined benefit retirement plan during 2002. At December 31, 2002, we also recorded a minimum pension liability of $102 million, net of taxes, which resulted in a charge to Accumulated Other Comprehensive Income (OCI) and a reduction to stockholders' equity.

Based on the performance of plan assets through December 31, 2002, we expect to be required under the Employee Retirement Income Security Act of 1974 to fund approximately $150 million to $175 million annually, including CILCORP, in 2005, 2006 and 2007 in order to maintain minimum funding levels for our pension plans. In addition, we estimate the pension funding for CILCORP to be less than $1 million in 2003 and approximately $5 million in 2004. These amounts are estimates and may change based on actual stock market performance, changes in interest rates, and any pertinent changes in government regulations. See Benefit Plan Accounting under Accounting Matters – Critical Accounting Policies below.

Investing

Our net cash used in investing activities was $803 million in 2002 compared to $1.1 billion in 2001 and $911 million in 2000. In 2002, construction expenditures in our rate-regulated operations were $603 million (2001 - $671 million; 2000 - $369 million), primarily related to various upgrades at our coal power plants and further construction of combustion turbine generating units. Construction expenditures in our non rate-regulated operations were $184 million in 2002 (2001 - $431 million; 2000 - $560 million), primarily related to the construction of combustion turbine generating units. In 2002, we placed into service 240 megawatts (approximately $135 million) of combustion turbine electric generation capacity in our rate-regulated operations and approximately 470 megawatts (approximately $215 million) in our non rate-regulated operations. In 2001 and 2000, we added approximately 850 megawatts (approximately $530 million) and approximately 690 megawatts (approximately $320 million), respectively, of non rate-regulated combustion turbine generating capacity.

For the five-year period 2003 through 2007, construction expenditures are estimated to approximate $3 billion - $3.3 billion, of which approximately $675 million is expected in 2003. This estimate includes capital expenditures related to CILCORP's operations, the purchase of new combustion turbine generating facilities at AmerenUE and the replacement of steam generators at AmerenUE's Callaway nuclear plant. In addition, this estimate includes capital expenditures for transmission, distribution and other generation-related activities, as well as for compliance with new NO_x (nitrogen oxide) control regulations, as discussed in Environmental below.

As a part of the settlement of the Missouri electric rate case in 2002 (see Regulatory Matters below), AmerenUE committed to making $2.25 billion to $2.75 billion in infrastructure investments from January 1, 2002 through June 30, 2006. These investments include, among other things, the addition of more than 700 megawatts of new generation capacity and the replacement of steam generators at AmerenUE's Callaway nuclear plant. The requirements for 700 megawatts of new generation are expected to be satisfied by 240 megawatts added in 2002, as discussed above, and the proposed transfer at net book value to AmerenUE of approximately 550 megawatts of generation assets from Generating Company, which is subject to receipt of necessary regulatory approvals.

We intend to add 117 megawatts of capacity by 2005 and at least 330 megawatts of capacity by 2006 at AmerenUE. Total costs expected to be incurred for these units approximate $175 million of which approximately $100 million was committed as of December 31, 2002.

We continually review our generation portfolio and expected electrical needs, and as a result, we could modify our plan for generation asset purchases, which could include the timing of when certain assets will be added to, or removed from our portfolio, the type of generation asset technology that will be employed, or whether capacity may be purchased, among other things. Any changes that Ameren may plan to make for future generating needs could result in significant capital expenditures or losses being incurred, which could be material.

Environmental

We are subject to various environmental regulations by federal, state, and local authorities. From the beginning phases of siting and development, to the ongoing operation of existing or new electric generating, transmission, and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, special, protected, and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical and waste handling, and noise impacts. Our activities require complex and often lengthy processes to obtain approvals, permits, or licenses for new, existing, or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires preparation of release prevention plans and emergency response procedures. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operations, as required.

The U.S. Environmental Protection Agency (EPA) issued a rule in October 1998 requiring 22 Eastern states and the District of Columbia to reduce emissions of NO_x in order to reduce ozone in the Eastern United States. Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_x emission budget for each state, including Illinois where most of Generating Company's facilities are located. The EPA rule requires states to implement controls sufficient to meet their NO_x budget by May 31, 2004.

As a result of these state requirements, Generating Company estimates spending an additional $40 million for pollution control capital expenditures and NO_x credits by 2006. A total of $90 million was spent in 2002 and 2001. In February 2002, the EPA proposed similar rules for Missouri where the majority of AmerenUE's facilities are located. Assuming the Missouri rules are ultimately finalized, AmerenUE estimates spending approximately $170 million to comply with these rules for NO_x control on the AmerenUE generating system by 2006. In summary, we currently estimate our future capital expenditures to comply with the final NO_x regulations could range from $200 million to $250 million. This estimate includes the assumption that the regulations will require the installation of Selective Catalytic Reduction technology on some of our units, as well as additional controls.

See Note 14 – Commitments and Contingencies to our Consolidated Financial Statements for further discussion of environmental matters and Note 15 – Callaway Nuclear Plant to our Consolidated Financial Statements for a discussion of Callaway Nuclear Plant decommissioning costs.

Financing

Our cash flows provided by financing activities totaled $531 million in 2002 and $307 million in 2001, compared to cash flows used in financing activities of $22 million for 2000. Our principal financing activities for the three year period included the issuance of long-term debt, adjustable conversion-rate equity security units and common stock, partially offset by redemptions of short-term debt, long-term debt and preferred stock, as well as payments of dividends.

Ameren Corporation, AmerenUE and AmerenCIPS are authorized by the SEC under PUHCA to have up to an aggregate of $1.5 billion, $1 billion and $250 million, respectively, of short-term unsecured debt instruments outstanding at any time. In addition, Generating Company is authorized by the Federal Energy Regulatory Commission (FERC) to have up to $300 million of short-term debt outstanding at any time.

Short-Term Debt and Liquidity

Short-term debt consists of commercial paper and bank loans (maturities generally within 1 to 45 days). At December 31, 2002, Ameren had committed credit facilities, expiring at various dates between 2003 and 2005, totaling $695 million, excluding EEI of $45 million and nuclear fuel lease facilities of $120 million. All of these amounts were available for use by our rate-regulated subsidiaries (AmerenUE and AmerenCIPS) and Ameren Services Company, and $600 million of this amount was available for use by Ameren Corporation and most of our non rate-regulated subsidiaries including, but not limited to, Resources Company, Generating Company, Marketing Company, AmerenEnergy Fuels and Services Company and AmerenEnergy. These committed credit facilities are used to support our commercial paper programs under which $250 million was outstanding at December 31, 2002. At December 31, 2002, $445 million was unused and available under these committed credit facilities.

In July 2002, Ameren Corporation entered into new committed credit agreements for $400 million in revolving credit facilities to be used for general corporate purposes, including support of our commercial paper programs. The $400 million in new facilities includes a $270 million 364-day revolving credit facility and a $130 million 3-year revolving credit facility. The 3-year facility has a $50 million sub-limit for the issuance of letters of credit. These new credit facilities replaced AmerenUE's $300 million revolving credit facility. These amounts are included in the total committed credit facilities of $695 million mentioned above.

Ameren Corporation had a $200 million committed credit facility which matured in December 2002. We expect to replace this bank credit agreement with two new credit facilities at AmerenUE, and we expect to extend or replace our other committed credit facilities upon their respective maturities.

These credit facilities make borrowings available at various interest rates based on LIBOR, agreed rates and other options.

We also have two bank credit agreements totaling $45 million that expire in 2003 at EEI. At December 31, 2002, $27 million was unused and available under these committed credit facilities.

AmerenUE also has a lease agreement that provides for the financing of nuclear fuel. At December 31, 2002, the maximum amount that could be financed under the agreement was $120 million. At December 31, 2002, $113 million was financed under the lease.

In addition to committed credit facilities, a further source of liquidity for Ameren is available cash and cash equivalents. At December 31, 2002, we had $628 million of cash. In early 2003, we paid a total of approximately $500 million of cash on hand to acquire CILCORP and Medina Valley.

We rely on access to short-term and long-term capital markets as a significant source of funding for capital requirements not satisfied by our operating cash flows. The inability by us to raise capital on favorable terms, particularly during times of uncertainty in the capital markets, could negatively impact our ability to maintain and grow our businesses. Based on our current credit ratings, we believe that we will continue to have access to the capital markets. However, events beyond our control may create uncertainty in the capital markets such that our cost of capital would increase or our ability to access the capital markets would be adversely affected.

The following table summarizes available borrowing capacity under our committed lines of credit and credit agreements as of December 31, 2002:

	Amount of Commitment Expiration Per Period				
	Total Committed	Less Than 1 Year	1 - 3 Years	4 - 5 Years	After 5 Years
Lines of credit and credit agreements:					
Ameren Corporation	$600	$470	$130	$–	$–
AmerenUE (a)	200	80	120	–	–
AmerenCIPS	15	15	–	–	–
EEI	45	45	–	–	–
Total	$860	$610	$250	$–	$–

(a) Includes $120 million Gateway Fuel Company facility due February 2004 which supports the nuclear fuel lease.

The following table summarizes our contractual obligations as of December 31, 2002:

	Total	Less Than 1 Year	1 - 3 Years	4 - 5 Years	After 5 Years
Long-term debt and capital lease obligations (a)	$3,780	$ 339	$ 656	$546	$2,239
Short-term debt	271	271	–	–	–
Operating leases (b)	171	22	35	26	88
Other long-term obligations (c)	2,441	706	981	370	384
Total cash contractual obligations	$6,663	$1,338	$1,672	$942	$2,711

(a) *Amounts include our contractual obligation for fabricated nuclear fuel for the years 2003 through 2006.*

(b) *Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The $1 million annual obligation for these items is included in the less than 1 year, 1-3 years and 4-5 years. Amounts for after 5 years are not included in the total amount due to the indefinite periods.*

(c) *Represents purchase contracts for coal, gas, nuclear fuel (including our contractual obligation for fabricated nuclear fuel for the years 2007 through 2012), and electric capacity.*

Indenture and Credit Agreement Provisions and Covenants

Our financial agreements include customary default or cross default provisions that could impact the continued availability of credit or result in the acceleration of repayment. Many of Ameren's committed credit facilities require the borrower to represent, in connection with any borrowing under the facility, that no material adverse change has occurred since certain dates. Ameren's financing arrangements do not contain credit rating triggers.

Covenants in Ameren Corporation's committed credit facilities require the maintenance of the percentage of total debt to total capital of 60% or less for Ameren, AmerenUE and AmerenCIPS. As of December 31, 2002, this ratio was 50%, 43% and 50% for Ameren Corporation, AmerenUE, and AmerenCIPS, respectively. Ameren Corporation's committed credit facilities also include indebtedness cross default provisions that could trigger a default under these facilities in the event any subsidiary of Ameren Corporation (subject to definition in the underlying credit agreements), other than certain project finance subsidiaries, defaults in indebtedness in excess of $50 million.

Most of Ameren's committed credit facilities include provisions related to the funded status of Ameren's pension plan. These provisions either require Ameren to meet minimum ERISA funding requirements or limit the unfunded liability status of the plan. Under the most restrictive of these provisions impacting facilities totaling $400 million, an event of default will result if the unfunded liability status (as defined in the underlying credit agreements) of Ameren's pension plan exceeds $300 million in the aggregate. Based on the most recent valuation report available to Ameren at December 31, 2002, which was based on January 2002 asset and liability valuations, the unfunded liability status (as defined) was $31 million. While an updated valuation report will not be available until the second half of 2003, we believe that the unfunded liability status of our pension plans (as defined) could exceed $300 million based on the investment performance of the pension plan assets and interest rate changes since January 1, 2002. As a result, we may need to renegotiate the facility provisions, terminate or replace the affected facilities, or fund any unfunded liability shortfall. Should we elect to terminate these facilities, we believe we would otherwise have sufficient liquidity to manage our short-term funding requirements.

Generating Company's senior note indenture includes provisions that require it to maintain a senior debt service coverage ratio of at least 1.75 to 1 (for both the prior four fiscal quarters and for the next succeeding four, six-month periods) in order to pay dividends, or to make payments of principal or interest under certain subordinate indebtedness, excluding amounts payable under an intercompany note payable with AmerenCIPS. For the four quarters ended December 31, 2002, this ratio was 4.10 to 1. In addition, the indenture also restricts Generating Company from incurring any additional indebtedness, with the exception of certain permitted indebtedness as defined in the indenture, unless its senior debt service coverage ratio equals at least 2.5 to 1 for the most recently ended four fiscal quarters and its senior debt to total capital ratio would not exceed 60%, both after giving effect to the additional indebtedness on a pro-forma basis. This debt incurrence requirement is disregarded in the event certain rating agencies reaffirm the ratings of Generating Company after considering the additional indebtedness. As of December 31, 2002, Generating Company's senior debt to total capital ratio was 55%.

At December 31, 2002, Ameren Corporation and its subsidiaries were in compliance with their indenture and credit agreement provisions and covenants.

Off-Balance Sheet Arrangements

At December 31, 2002, neither Ameren Corporation, nor any of its subsidiaries, had any off-balance sheet financing arrangements, other than operating leases entered into in the ordinary course of business. We do not expect to engage in any significant off-balance sheet financing arrangements in the near future.

Long-Term Debt and Equity

The following table summarizes our issuances of common stock and the issuances and redemptions of long-term debt for the years ended 2002, 2001 and 2000. For additional information related to the terms and uses of these issuances and the sources of funds and terms for redemptions, see Note 8 – Long-Term Debt and Capitalization to our Consolidated Financial Statements.

	Month Issued/ Redeemed	2002	2001	2000
Issuances –				
Long-term debt:				
Ameren Corporation:				
5.70% Notes, due 2007	Jan	$100	$ –	$ –
Senior notes, due 2007 (a)	Mar	345	–	–
Floating rate notes, due 2003	Dec	–	150	–
AmerenUE:				
5.25% Senior secured notes, due 2012	Aug	173	–	–
Environ. improvement revenue bonds	Mar	–	–	187
Generating Company:				
7.95% Senior notes, due 2032	June	275	–	–
7.75% Senior notes, due 2005	Nov	–	–	225
8.35% Senior notes, due 2010	Nov	–	–	200
AmerenCIPS:				
6.625% Senior secured notes, due 2011	Jun	–	150	–
Pollution control revenue bonds	Mar	–	–	51
Electric Energy Inc.:				
Bank term loan, due 2004	Jun	–	–	40
Total long-term debt issuances		$893	$300	$703
Equity:				
5,000,000 Shares at $39.50	Mar	$198	$ –	$ –
750,000 Shares at $38.865	Mar	29	–	–
8,050,000 Shares at $42.00	Sep	338	–	–
DRPlus and employee benefit plans (b)	Various	93	33	–
Total common stock issuances		$658	$ 33	$ –
Redemptions –				
Long-term debt:				
AmerenUE:				
8.33% First mortgage bonds	Dec	$ 75	$ –	$ –
8.75% First mortgage bonds	Sep	125	–	–
Environ. improvement bonds, 7.40% series	May	–	–	60
Environ. improvement bonds, 1985 series	Apr	–	–	127
Commercial paper, net	Various	–	18	132
AmerenCIPS:				
First mortgage bonds	Various	32	30	35
Environ. improvement bonds, 1990 A series	Apr	–	–	20
Environ. improvement bonds, 1990 B series	Apr	–	–	32
Electric Energy Inc.:				
1991 8.60% Senior MTNs, amortization	Dec	7	7	7
1994 6.61% Senior MTNs, amortization	Dec	8	8	8
Total long-term debt redemptions		$247	$ 63	$421

(a) *A component of the adjustable conversion-rate equity security units. See Note 8 - Long-Term Debt and Capitalization for further discussion.*

(b) *Includes issuances of common stock of 2.3 million shares in 2002 and 0.8 million shares in 2001 under our dividend reinvestment and stock purchase plan (DRPlus) and in connection with our 401(k) plans.*

Ameren Corporation

In August 2002, a shelf registration statement filed by Ameren Corporation with the SEC on Form S-3 was declared effective. This statement authorized the offering from time to time of up to $1.473 billion of various forms of securities including long-term debt, and trust preferred and equity securities to finance ongoing construction and maintenance programs, to redeem, repurchase, repay, or retire outstanding debt, to finance strategic investments, including our then pending acquisition of CILCORP, and for general corporate purposes. In 2002 and in early 2003, $594 million was issued under the shelf registration statement. At February 13, 2003, the amount remaining on the shelf registration statement was approximately $879 million. See discussion of the 2003 common stock offering under Recent Developments above.

We may sell all, or a portion of, the remaining registered securities under the Ameren Corporation shelf registration statement if warranted by market conditions and our capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

In September 2001, we began issuing new shares of common stock under our DRPlus, and in December 2001 we began issuing new shares of common stock in connection with our 401(k) plans. Previously, these requirements were met by purchasing outstanding common shares on the open market. We plan to continue to issue new shares of common stock under our DRPlus and 401(k) plans in 2003.

Ameren expects to fund maturities of long-term debt and contractual obligations through a combination of cash flow from operations and external financing.

AmerenUE

In August 2002, a shelf registration statement filed by AmerenUE with the SEC on Form S-3 was declared effective. This statement authorized the offering from time to time of up to $750 million of various forms of long-term debt and trust preferred securities to refinance existing debt and preferred stock, and for general corporate purposes, including the repayment of short-term debt incurred to finance construction expenditures and other working capital needs. In 2002, AmerenUE issued $173 million under the shelf registration statement. At February 13, 2003, the amount remaining under the shelf registration statement was $577 million.

AmerenCIPS

In May 2001, a shelf registration statement filed by AmerenCIPS with the SEC on Form S-3 was declared effective. This statement authorized the offering from time to time of senior notes in one or more series with an offering price not to exceed $250 million. In June 2001, AmerenCIPS issued $150 million of senior notes under the shelf registration statement. At February 13, 2003, the amount remaining on the shelf registration statement was $100 million.

Dividends

Common stock dividends paid in 2002 resulted in a payout rate of 98% of our net income (85% of net income excluding voluntary retirement and other restructuring charges) (75% - 2001; 76% - 2000). Dividends paid to common stockholders in relation to net cash provided by operating activities for the same periods were 45%, 47% and 40%.

The Board of Directors does not set specific targets or payout parameters when declaring common stock dividends. However, the Board considers various issues, including our historic earnings and cash flow; projected earnings; cash flow and potential cash flow requirements; dividend payout rates at other utilities; return on investments with similar risk characteristics; and overall business considerations. On February 14, 2003, our Board of Directors declared a quarterly common stock dividend of 63.5 cents per share to be paid on March 31, 2003 to shareholders of record on March 12, 2003.

OUTLOOK

We believe there will be challenges to earnings in 2003 and beyond due to industry-wide trends and company-specific issues. The following are expected to put pressure on earnings in 2003 and beyond:

- Weak economic conditions, which impacts native load demand,
- Generally soft power prices in the Midwest are expected to limit the amount of revenues Ameren can generate by marketing its excess power into the interchange markets,
- Our revenues will be reduced by a rate settlement approved in 2002 by the Missouri Public Service Commission (MoPSC) that requires the phase-in of $110 million of electric rate reductions from 2002 through 2004,
- The adverse effects of rising employee benefit costs, higher insurance costs and increased security costs associated with additional measures we have taken, or may have to take, at our Callaway nuclear plant related to world events,
- The incremental dilution from equity issued in both 2002 and 2003, and
- An assumed return to more normal weather patterns.

In late 2002, we announced the following actions to mitigate the effect of these challenges:

- A voluntary retirement program that was accepted by approximately 550 employees,
- Modifications to retiree employee benefit plans to increase co-payments and limit our overall cost,
- A wage freeze in 2003 for all management employees,
- Suspension of operations at two 1940's-era generating plants to reduce operating costs, and
- Reductions of 2003 expected capital expenditures.

We are pursuing gas rate increases of approximately $34 million in Illinois and are considering a gas rate increase request in Missouri. We are also considering additional actions, including modifications to active employee benefits, further staffing reductions, accelerating synergy opportunities related to the CILCORP acquisition and other initiatives.

In the ordinary course of business, we evaluate strategies to enhance our financial position, results of operations and liquidity. These strategies may include potential acquisitions, divestitures, and opportunities to reduce costs or increase revenues, and other strategic initiatives in order to increase shareholder value. We are unable to predict which, if any, of these initiatives will be executed, as well as the impact these initiatives may have on our future financial position, results of operations or liquidity.

REGULATORY MATTERS

Missouri

From July 1, 1995 through June 30, 2001, our subsidiary, AmerenUE, operated under experimental alternative regulation plans in Missouri that provided for the sharing of earnings with customers if our regulatory return on equity exceeded defined threshold levels. After AmerenUE's experimental alternative regulation plan for its Missouri retail electric customers expired, the MoPSC Staff and others sought to reduce our annual Missouri electric revenues by over $300 million. The MoPSC Staff's recommendation was based on a return to traditional cost of service ratemaking, a lowered return on equity, a reduction in AmerenUE's depreciation rates and other cost of service adjustments.

In August 2002, a stipulation and agreement resolving this case became effective following agreement by all parties to the case and approval by the MoPSC. The stipulation and agreement includes the following principal features:

- The phase-in of $110 million of electric rate reductions through April 2004, $50 million of which was retroactively effective as of April 1, 2002, $30 million of which will become effective on April 1, 2003, and $30 million of which will become effective on April 1, 2004.
- A rate moratorium providing for no changes in rates before June 30, 2006, subject to certain statutory and other exceptions.
- A commitment to contribute $14 million to programs for low income energy assistance and weatherization, promotion of energy efficiency and economic development in AmerenUE's service territory in 2002, with additional payments of $3 million made annually on June 30, 2003 through June 30, 2006. This entire obligation was expensed in 2002.
- A commitment to make $2.25 billion to $2.75 billion in critical energy infrastructure investments from January 1, 2002 through June 30, 2006, including, among other things, the addition of more than 700 megawatts of new generation capacity and the replacement of steam generators at AmerenUE's Callaway nuclear plant. The 700 megawatts of new generation is expected to be satisfied by 240 megawatts that were added by AmerenUE in 2002 and the proposed transfer at net book value to AmerenUE of approximately 550 megawatts of generation assets from Generating Company, which is subject to receipt of necessary regulatory approvals.
- An annual reduction in AmerenUE's depreciation rates by $20 million, retroactive to April 1, 2002, based on an updated analysis of asset values, service lives and accumulated depreciation levels.
- A one-time credit of $40 million which was accrued during the plan period. The entire amount was paid to AmerenUE's Missouri retail electric customers in 2002 for the settlement of the final sharing period under the alternative regulation plan that expired June 30, 2001.

See Note 2 – Rate and Regulatory Matters to our Consolidated Financial Statements.

Illinois

See Note 2 – Rate and Regulatory Matters to our Consolidated Financial Statements.

Federal – Electric Transmission

See Note 2 – Rate and Regulatory Matters to our Consolidated Financial Statements.

ACCOUNTING MATTERS

Critical Accounting Policies

Preparation of the financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. Our application of these policies involves judgments regarding many factors, which, in and of themselves, could materially impact the financial statements and disclosures. A future change in the assumptions or judgments applied in determining the following matters, among others, could have a material impact on future financial results. In the table below, we have outlined those accounting policies that we believe are most difficult, subjective or complex:

Accounting Policy	Uncertainties Affecting Application
Regulatory Mechanisms and Cost Recovery We defer costs as regulatory assets in accordance with SFAS 71 and make investments that we assume we will be able to collect in future rates.	■ Regulatory environment, external regulatory decisions and requirements ■ Anticipated future regulatory decisions and their impact ■ Impact of deregulation and competition on ratemaking process and ability to recover costs
Basis for Judgment We determine that costs are recoverable based on previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable.	
Nuclear Plant Decommissioning Costs In our rates and earnings we assume the Department of Energy will develop a permanent storage site for spent nuclear fuel, the Callaway nuclear plant will have a useful life of 40 years and estimated costs of approximately $515 million to dismantle the plant are accurate. See Note 15 – Callaway Nuclear Plant to our Consolidated Financial Statements.	■ Estimates of future decommissioning costs ■ Availability of facilities for waste disposal ■ Approved methods for waste disposal and decommissioning ■ Useful lives of nuclear plants
Basis for Judgment We determine that decommissioning costs are reasonable, or require adjustment, based on third party decommissioning studies that are completed every three years, the evaluation of our facilities by our engineers and the monitoring of industry trends.	

Table Continued on Page 30

Table Continued from Page 29

Accounting Policy	Uncertainties Affecting Application
Environmental Costs We accrue for all known environmental contamination where remediation can be reasonably estimated, but some of our operations have existed for over 100 years and previous contamination may be unknown to us.	▪ Extent of contamination ▪ Responsible party determination ▪ Approved methods for cleanup ▪ Present and future legislation and governmental regulations and standards ▪ Results of ongoing research and development regarding environmental impacts
Basis for Judgment We determine the proper amounts to accrue for environmental contamination based on internal and third party estimates of clean-up costs in the context of current remediation standards and available technology.	
Unbilled Revenue At the end of each period, we estimate, based on expected usage, the amount of revenue to record for services that have been provided to customers, but not billed. This period can be up to one month.	▪ Projecting customer energy usage ▪ Estimating impacts of weather and other usage-affecting factors for the unbilled period
Basis for Judgment We determine the proper amount of unbilled revenue to accrue each period based on the volume of energy delivered as valued by a model of billing cycles and historical usage rates and growth by customer class for our service area, as adjusted for the modeled impact of seasonal and weather variations based on historical results.	
Benefit Plan Accounting Based on actuarial calculations, we accrue costs of providing future employee benefits in accordance with SFAS 87, 106 and 112. See Note 12 – Retirement Benefits to our Consolidated Financial Statements.	▪ Future rate of return on pension and other plan assets ▪ Interest rates used in valuing benefit obligations ▪ Healthcare cost trend rates ▪ Timing of employee retirements
Basis for Judgment We utilize a third party consultant to assist us in evaluating and recording the proper amount for future employee benefits. Our ultimate selection of the discount rate, healthcare trend rate and expected rate of return on pension assets is based on our review of available current, historical and projected rates, as applicable.	
Derivative Financial Instruments We record all derivatives at their fair market value in accordance with SFAS 133. The identification and classification of a derivative, and the fair value of such derivative must be determined. We designate certain derivatives as hedges of future cash flows. See Note 3 – Derivative Financial Instruments to our Consolidated Financial Statements.	▪ Market conditions in the energy industry, especially the effects of price volatility on contractual commodity commitments ▪ Regulatory and political environments and requirements ▪ Fair value estimations on longer term contracts ▪ Complexity of financial instruments and accounting rules ▪ Effectiveness of our derivatives that have been designated as hedges
Basis for Judgment We determine whether a transaction is a derivative versus a normal purchase or sale based on historical practice and our intention at the time we enter a transaction. We utilize actively quoted prices, prices provided by external sources, and prices based on internal models, and other valuation methods to determine the fair market value of derivative financial instruments.	

Impact of Future Accounting Pronouncements

See Note 1 – Summary of Significant Accounting Policies to our Consolidated Financial Statements.

EFFECTS OF INFLATION AND CHANGING PRICES

Our rates for retail electric and gas utility service are regulated by the MoPSC and the Illinois Commerce Commission (ICC). Non-retail electric rates are regulated by the FERC. Our Missouri electric rates have been set through June 30, 2006, as part of the settlement of our Missouri electric rate case and our Illinois electric rates are legislatively fixed through January 1, 2007. Inflation affects our operations, earnings, stockholders' equity and financial performance.

The current replacement cost of our utility plant substantially exceeds our recorded historical cost. Under existing regulatory practice, only the historical cost of plant is recoverable from customers. As a result, cash flows designed to provide recovery of historical costs through depreciation might not be adequate to replace plant in future years. Ameren's generation portion of its business in its Illinois jurisdiction is non rate-regulated and therefore does not have regulated recovery mechanisms.

In our retail electric utility jurisdictions, there are no provisions for adjusting rates for changes in the cost of fuel for electric generation. In our retail gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through purchased gas adjustment clauses. We are impacted by changes in market prices for natural gas to the extent we must purchase natural gas to run our combustion turbine electric generators. We have structured various supply agreements to maintain access to multiple gas pools and supply basins to minimize the impact to the financial statements. See discussion below under Commodity Price Risk for further information.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk represents the risk of changes in value of a physical asset or a financial instrument, derivative or non-derivative, caused by fluctuations in market variables (e.g., interest rates, etc.). The following discussion of our risk management activities includes "forward-looking" statements that involve risks and uncertainties. Actual results could differ materially from those projected in the "forward-looking" statements. We handle market risks in accordance with established policies, which may include entering into various derivative transactions. In the normal course of business, we also face risks that are either non-financial or non-quantifiable. Such risks principally include business, legal and operational risks and are not represented in the following discussion.

Our risk management objective is to optimize our physical generating assets within prudent risk parameters. Our risk management policies are set by a Risk Management Steering Committee, which is comprised of senior-level Ameren officers.

Interest Rate Risk

We are exposed to market risk through changes in interest rates associated with both long-term and short-term variable-rate debt and fixed-rate debt, commercial paper, auction-rate long-term debt and auction-rate preferred stock. We manage our interest rate exposure by controlling the amount of these instruments we hold within our total capitalization portfolio and by monitoring the effects of market changes in interest rates.

Utilizing our debt outstanding at December 31, 2002, if interest rates increased by 1%, our annual interest expense would increase by approximately $11 million and net income would decrease by approximately $7 million. The model does not consider the effects of the reduced level of potential overall economic activity that would exist in such an environment. In the event of a significant change in interest rates, management would likely take actions to further mitigate our exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no change in our financial structure.

Credit Risk

Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted. New York Mercantile Exchange (NYMEX) traded futures contracts are supported by the financial and credit quality of the clearing members of the NYMEX and have nominal credit risk. On all other transactions, we are exposed to credit risk in the event of nonperformance by the counterparties in the transaction.

Our physical and financial instruments are subject to credit risk consisting of trade accounts receivables and executory contracts with market risk exposures. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising our customer base. No customer represents greater than 10% of our accounts receivable. Our revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. We analyze each counterparty's financial condition prior to entering into sales, forwards, swaps, futures or option contracts and monitor counterparty exposure associated with our leveraged leases. As of December 31, 2002, we had approximately $29 million invested in three leveraged leases. We also establish credit limits for these counterparties and monitor the appropriateness of these limits on an ongoing basis through a credit risk management program which involves daily exposure reporting to senior management, master trading and netting agreements, and credit support management such as letters of credit and parental guarantees.

Commodity Price Risk

We are exposed to changes in market prices for natural gas, fuel and electricity. We utilize several techniques to mitigate risk, including utilizing derivative financial instruments. A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset. The derivative financial instruments that we use (primarily forward contracts, futures contracts, option contracts and financial swap contracts) are dictated by risk management policies.

With regard to our natural gas utility business, our exposure to changing market prices is in large part mitigated by the fact we have gas cost recovery mechanisms in place in both Missouri and Illinois. These gas cost recovery mechanisms allow us to pass on to retail customers our prudently incurred costs of natural gas.

AmerenEnergy Fuels and Services Company is responsible for providing fuel procurement and gas supply services on behalf of our operating subsidiaries, and for managing fuel and natural gas price risks. Fixed price forward contracts, as well as futures, options, and financial swaps are all instruments, which may be used to manage these risks. The majority of our fuel supply contracts are physical forward contracts. Since we do not have a provision similar to the purchased gas adjustment clauses for our electric operations, we have entered into long-term contracts with various suppliers to purchase coal and nuclear fuel in order to manage our exposure to fuel prices. See Note 14 – Commitments and Contingencies to our Consolidated Financial Statements for further information. Approximately 98% of the required 2003 and over 80% of the required 2004 supply of coal for our coal-fired power plants has been acquired at fixed prices. As such, we have minimal coal price risk for 2003 and 2004. At December 31, 2002, approximately 30% of our coal requirements for 2005 through 2007 were covered by contracts. We have satisfied 77%, 11% and 2% of our historical needs through coal, nuclear and hydro generation, respectively. With regard to our electric generating operations, we are exposed to changes in market prices for natural gas to the extent we must purchase natural gas to run our combustion turbine generators. At December 31, 2002, approximately 36% of our 2003 natural gas requirements for generation are covered by contracts. Our natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to our intermediate and peaking units by optimizing transportation and storage options and minimizing cost and price risk by structuring various supply agreements to maintain access to multiple gas pools and supply basins and reducing the impact of price volatility.

Although we cannot completely eliminate the effects of gas price volatility, our strategy is designed to minimize the effect of market conditions on our results of operations. Our gas procurement strategy includes procuring natural gas under a portfolio of agreements with price structures, including fixed price, indexed price and embedded price hedges such as caps and collars. Our strategy also utilizes physical assets through storage, operator and balancing agreements to minimize price volatility. Ameren's electric marketing strategy is to extract additional value from its generation facilities by selling energy in excess of needs into the long-term and short-term markets for term sales, and purchasing energy when the market price is less than the cost of generation. Our primary use of derivatives has involved transactions that are expected to reduce price risk exposure for us.

With regard to our exposure to commodity price risk for purchased power and excess electricity sales, we have a subsidiary, AmerenEnergy, whose primary responsibility includes managing market risks associated with changing market prices for electricity purchased and sold on behalf of AmerenUE and Generating Company. In addition, we have sold nearly all of our available non rate-regulated peak generation capacity for the summer of 2003 at various prices.

Equity Price Risk

Our costs of providing non-contributory defined benefit retirement and post-retirement benefit plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rate, the rate of increase in health care costs and contributions made to the plans. The market value of our plan assets has been affected by declines in the equity market since 2000 for our pension and post-retirement plans. As a result, at

December 31, 2002, we recognized an additional minimum pension liability as prescribed by SFAS No. 87, "Employers' Accounting for Pensions." The liability resulted in a reduction to equity as a result of a charge to OCI of $102 million, net of taxes. The amount of the liability was the result of asset returns experienced through 2002, interest rates and our contributions to the plans during 2002. In future years, the liability recorded, the costs reflected in net income, or OCI, or cash contributions to the plans could increase materially without a recovery in equity markets in excess of our assumed return on plan assets. If the fair value of the plan assets were to grow and exceed the accumulated benefit obligations in the future, then the recorded liability would be reduced and a corresponding amount of equity would be restored in the Consolidated Balance Sheet. See Liquidity and Capital Resources – Operating.

We also maintain trust funds, as required by the Nuclear Regulatory Commission and Missouri and Illinois state laws, to fund certain costs of nuclear decommissioning. See Note 15 – Callaway Nuclear Plant to our Consolidated Financial Statements for further information. As of December 31, 2002, these funds were invested primarily in domestic equity securities (62%), debt securities (35%), and cash and cash equivalents (3%) and totaled $172 million at fair value. By maintaining a portfolio that includes long-term equity investments, we seek to maximize the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in our portfolio are exposed to price fluctuations in equity markets and the fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, established target allocation percentages of the assets of our trusts to various investment options. Our exposure to equity price market risk is, in large part, mitigated, due to the fact that we are currently allowed to recover decommissioning costs in our rates.

Fair Value of Contracts

We utilize derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause:

- an unrealized appreciation or depreciation of our firm commitments to purchase or sell when purchase or sales prices under the firm commitment are compared with current commodity prices;
- market values of fuel and natural gas inventories or purchased power to differ from the cost of those commodities in inventory under firm commitment; and
- actual cash outlays for the purchase of these commodities to differ from anticipated cash outlays.

The derivatives that we use to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. We continually assess our supply and delivery commitment positions against forward market prices and internally forecast forward prices and modify our exposure to market, credit and operational risk by entering into various offsetting transactions. In general, we believe these transactions serve to reduce our price risk. See Note 3 – Derivative Financial Instruments to our Consolidated Financial Statements for further information.

The following table summarizes the favorable (unfavorable) changes in the fair value of all contracts marked to market during 2002 and 2001:

	2002	2001
Fair value of contracts at beginning of period, net	$(1)	$(30)
Contracts which were realized or otherwise settled during the period	(7)	30
Changes in fair values attributable to changes in valuation techniques and assumptions	–	–
Fair value of new contracts entered into during the period	1	4
Other changes in fair value	14	(5)
Fair value of contracts outstanding at end of period, net	$ 7	$ (1)

Maturities of contracts as of December 31, 2002 were as follows:

	Maturity				
	Less Than 1 year	1 - 3 Years	4 - 5 Years	In Excess of 5 Years	Total Fair Value (a)
Sources of fair value:					
Prices actively quoted	$(1)	$–	$–	$–	$(1)
Prices provided by other external sources (b)	3	–	–	–	3
Prices based on models and other valuation methods (c)	4	1	–	–	5
Total	$ 6	$ 1	$–	$–	$ 7

(a) Contracts of approximately 7% of the absolute fair value were with non-investment-grade rated counterparties.

(b) Principally power forward values based on NYMEX prices for over-the-counter contracts and natural gas swaps based on Inside FERC prices.

(c) Principally coal and sulfur dioxide option values based on a Black-Scholes model that includes information from external sources and our estimates.

FORWARD LOOKING STATEMENTS

Statements made in this annual report which are not based on historical facts are "forward-looking" and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such "forward-looking" statements have been made in good faith and are based on reasonable assumptions, there is no assurance that the expected results will be achieved. These statements include (without limitation) statements as to future expectations, beliefs, plans, strategies, objectives, events, conditions and financial performance. In connection with the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause actual results to differ materially from those anticipated. The following factors, in addition to those discussed elsewhere in this report and in subsequent securities filings, could cause results to differ materially from management expectations as suggested by such "forward-looking" statements:

- the effects of the stipulation and agreement relating to the AmerenUE Missouri electric excess earnings complaint case and other regulatory actions, including changes in regulatory policy;
- changes in laws and other governmental actions, including monetary and fiscal policies;
- the impact on us of current regulations related to the opportunity for customers to choose alternative energy suppliers in Illinois;
- the effects of increased competition in the future due to, among other things, deregulation of certain aspects of our business at both the state and federal levels;
- the effects of participation in a FERC-approved Regional Transmission Organization, including activities associated with the Midwest ISO;
- availability and future market prices for fuel and purchased power, electricity and natural gas, including the use of financial and derivative instruments and volatility of changes in market prices;
- average rates for electricity in the Midwest;
- business and economic conditions;
- the impact of the adoption of new accounting standards on the application of appropriate technical accounting rules and guidance;
- interest rates and the availability of capital;
- actions of rating agencies and the effects of such actions;
- weather conditions;
- generation plant construction, installation and performance;
- operation of nuclear power facilities and decommissioning costs;
- the effects of strategic initiatives, including acquisitions and divestitures;
- the impact of current environmental regulations on utilities and generating companies and the expectation that more stringent requirements will be introduced over time, which could potentially have a negative financial effect;
- future wages and employee benefit costs, including changes in returns of benefit plan assets;
- disruptions of the capital markets or other events making our access to necessary capital more difficult or costly;
- competition from other generating facilities, including new facilities that may be developed in the future;
- difficulties in integrating CILCO with Ameren's other businesses;
- changes in the coal markets, environmental laws or regulations or other factors adversely impacting synergy assumptions in connection with the CILCORP acquisition;
- cost and availability of transmission capacity for the energy generated by our generating facilities or required to satisfy energy sales made by Ameren; and
- legal and administrative proceedings.

Given these uncertainties, undue reliance should not be placed on these forward-looking statements. Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In Millions, Except Per Share Amounts — Year Ended December 31,	2002	2001	2000
Operating revenues:			
Electric	$3,520	$3,507	$3,526
Gas	315	342	324
Other	6	9	6
Total operating revenues	3,841	3,858	3,856
Operating expenses:			
Fuel and purchased power	825	914	1,025
Gas	198	222	210
Other operations and maintenance	1,160	1,090	1,032
Voluntary retirement and other restructuring charges (Note 9)	92	–	–
Depreciation and amortization	431	406	383
Income taxes	250	300	301
Other taxes	262	261	265
Total operating expenses	3,218	3,193	3,216
Operating income	623	665	640
Other income and (deductions):			
Allowance for equity funds used during construction	6	13	5
Miscellaneous, net -			
Miscellaneous income (Note 10)	15	22	14
Miscellaneous expense (Note 10)	(50)	(16)	(21)
Income taxes	13	(5)	3
Total other income and (deductions)	(16)	14	1
Interest charges and preferred dividends:			
Interest	219	199	180
Allowance for borrowed funds used during construction	(5)	(8)	(8)
Preferred dividends of subsidiaries	11	12	12
Net interest charges and preferred dividends	225	203	184
Income before cumulative effect of change in accounting principle	382	476	457
Cumulative effect of change in accounting principle, net of income taxes	–	(7)	–
Net Income	$ 382	$ 469	$ 457
Earnings per common share – basic:			
Income before cumulative effect of change in accounting principle	$ 2.61	$ 3.46	$ 3.33
Cumulative effect of change in accounting principle, net of income taxes	–	(0.05)	–
Net income	$ 2.61	$3.41	$ 3.33
Earnings per common share – diluted:			
Income before cumulative effect of change in accounting principle	$ 2.60	$ 3.45	$ 3.33
Cumulative effect of change in accounting principle, net of income taxes	–	(0.05)	–
Net income	$ 2.60	$ 3.40	$ 3.33
Average Common Shares Outstanding (Note 1)	146.1	137.3	137.2

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

In Millions, Except Per Share Amounts — December 31,	2002	2001
Assets:		
Property and plant, net (Note 4)	$ 8,914	$ 8,427
Investments and other assets:		
Investments	38	39
Nuclear decommissioning trust fund	172	187
Other assets	233	114
Total investments and other assets	443	340
Current assets:		
Cash and cash equivalents	628	67
Accounts receivable – trade (less allowance for doubtful accounts of $7 and $9, respectively)	266	218
Unbilled revenue	176	171
Miscellaneous accounts and notes receivable	44	71
Materials and supplies, at average cost	299	295
Other current assets	39	41
Total current assets	1,452	863
Regulatory assets	690	771
Total Assets	$11,499	$10,401
Capital and liabilities:		
Capitalization:		
Common stock, $.01 par value, 400.0 shares authorized – shares outstanding of 154.1 and 138.0, respectively (Notes 6 and 8)	$ 2	$ 1
Other paid-in capital, principally premium on common stock	2,203	1,614
Retained earnings	1,739	1,733
Accumulated other comprehensive income	(93)	5
Other	(9)	(4)
Total common stockholders' equity	3,842	3,349
Preferred stock not subject to mandatory redemption (Note 6)	193	235
Long-term debt, net (Note 8)	3,433	2,835
Total capitalization	7,468	6,419
Minority interest in consolidated subsidiaries	15	4
Current liabilities:		
Current maturities of long-term debt (Note 8)	339	139
Short-term debt (Note 7)	271	641
Accounts and wages payable	369	392
Accumulated deferred income taxes	5	58
Taxes accrued	45	132
Other current liabilities	172	219
Total current liabilities	1,201	1,581
Commitments and contingencies (Notes 1, 2, 14, and 15)		
Accumulated deferred income taxes	1,707	1,563
Accumulated deferred investment tax credits	149	158
Regulatory liabilities	136	172
Accrued pension liabilities	377	88
Other deferred credits and liabilities	446	416
Total Capital and Liabilities	$11,499	$10,401

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

In Millions Year Ended December 31,	2002	2001	2000
Cash flows from operating:			
Net income	$382	$469	$457
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of change in accounting principle	–	7	–
Depreciation and amortization	431	406	383
Amortization of nuclear fuel	30	29	37
Amortization of debt issuance costs and premium/discounts	8	5	6
Allowance for funds used during construction	(11)	(21)	(13)
Deferred income taxes, net	74	28	2
Deferred investment tax credits, net	(9)	(6)	(7)
Voluntary retirement and other restructuring charges	92	–	–
Other	8	(1)	(2)
Changes in assets and liabilities:			
Receivables, net	(26)	70	(140)
Materials and supplies	(4)	(68)	26
Accounts and wages payable	(80)	(71)	122
Taxes accrued	38	8	(31)
Assets, other	(1)	(54)	(8)
Liabilities, other	(99)	(63)	32
Net cash provided by operating activities	833	738	864
Cash flows from investing:			
Construction expenditures	(787)	(1,102)	(929)
Allowance for funds used during construction	11	21	13
Nuclear fuel expenditures	(28)	(24)	(21)
Other	1	1	26
Net cash used in investing activities	(803)	(1,104)	(911)
Cash flows from financing:			
Dividends on common stock	(376)	(350)	(349)
Capital issuance costs	(35)	–	(8)
Redemptions:			
Nuclear fuel lease	–	(64)	(11)
Short-term debt	(370)	–	–
Long-term debt	(247)	(63)	(421)
Preferred stock	(42)	–	–
Issuances:			
Common stock	658	33	–
Nuclear fuel lease	50	13	9
Short-term debt	–	438	55
Long-term debt	893	300	703
Net cash provided by (used in) financing activities	531	307	(22)
Net change in cash and cash equivalents	561	(59)	(69)
Cash and cash equivalents at beginning of year	67	126	195
Cash and Cash Equivalents at End of Year	$628	$ 67	$126
Cash paid during the periods:			
Interest	$221	$187	$169
Income taxes, net	140	266	312

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMMON STOCKHOLDERS' EQUITY

In Millions — Year Ended December 31,	2002	2001	2000
Common stock:			
Beginning balance	$ 1	$ 1	$ 1
Shares issued	1	–	–
	2	1	1
Other paid-in capital:			
Beginning balance	1,614	1,581	1,582
Shares issued (less issuance costs of $20, $-, and $-, respectively)	637	33	–
Contracted stock purchase payment obligations	(46)	–	–
Employee stock awards	(2)	–	(1)
	2,203	1,614	1,581
Retained earnings:			
Beginning balance	1,733	1,614	1,506
Net income	382	469	457
Dividends	(376)	(350)	(349)
	1,739	1,733	1,614
Accumulated other comprehensive income:			
Beginning balance - derivative financial instruments	5	–	–
Change in derivative financial instruments in current period	4	5	–
	9	5	–
Beginning balance - minimum pension liability	–	–	–
Change in minimum pension liability in current period	(102)	–	–
	(102)	–	–
	(93)	5	–
Other:			
Beginning balance	(4)	–	–
Restricted stock compensation awards	(7)	(5)	–
Compensation amortized and mark-to-market adjustments	2	1	–
	(9)	(4)	–
Total common stockholders' equity	$3,842	$3,349	$3,196
Comprehensive income, net of taxes:			
Net income	$ 382	$ 469	$ 457
Unrealized net gain/(loss) on derivative hedging instruments, net of income taxes of $3, $3, and $-, respectively	6	5	–
Reclassification adjustments for gains/(losses) included in net income, net of income taxes of $(1), $7, and $-, respectively	(2)	11	–
Cumulative effect of accounting change, net of income taxes of $-, $(7), and $-, respectively	–	(11)	–
Minimum pension liability adjustment, net of income taxes of $(62), $-, and $-, respectively	(102)	–	–
Total comprehensive income, net of taxes	$ 284	$ 474	$ 457
Common stock shares at beginning of period	138.0	137.2	137.2
Shares issued	16.1	0.8	–
Common stock shares at end of period	154.1	138.0	137.2

See Notes to Consolidated Financial Statements.

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Ameren Corporation is a public utility holding company registered under the Public Utility Holding Company Act of 1935 (PUHCA) and is headquartered in St. Louis, Missouri. Our principal business is the generation, transmission and distribution of electricity, and the distribution of natural gas to residential, commercial, industrial and wholesale users in the central United States. Our primary subsidiaries are as follows:

- Union Electric Company, which operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois as AmerenUE.
- Central Illinois Public Service Company, which operates a rate-regulated electric and natural gas transmission and distribution business in Illinois as AmerenCIPS.
- Central Illinois Light Company is a subsidiary of CILCORP Inc., which operates a rate-regulated transmission and distribution business, an electric generation business, and a rate-regulated natural gas distribution business in Illinois as AmerenCILCO. We completed our acquisition of CILCORP on January 31, 2003 from The AES Corporation (AES). See Note 18 – Subsequent Event for further information.
- AmerenEnergy Resources Company (Resources Company), which consists of non rate-regulated operations. Subsidiaries include AmerenEnergy Generating Company (Generating Company) that operates our non rate-regulated electric generation in Missouri and Illinois, AmerenEnergy Marketing Company (Marketing Company), which markets power for periods over one year, AmerenEnergy Fuels and Services Company, which procures fuel and manages the related risks for our affiliated companies and AmerenEnergy Medina Valley Cogen (No. 4), LLC, which indirectly owns a 40 megawatt, gas-fired electric generation plant. On February 4, 2003, we completed our acquisition of AES Medina Valley Cogen (No. 4), LLC from AES and renamed it AmerenEnergy Medina Valley Cogen (No. 4), LLC. See Note 18 – Subsequent Event for further information.
- AmerenEnergy, Inc. (AmerenEnergy) which serves as a power marketing and risk management agent for our affiliated companies for transactions of primarily less than one year.
- Electric Energy, Inc. (EEI), which operates electric generation and transmission facilities in Illinois. We have a 60% ownership interest in EEI and consolidate it for financial reporting purposes.
- Ameren Services Company, which provides shared support services to us and our subsidiaries.

When we refer to Ameren, our, we or us, we are referring to Ameren Corporation and its subsidiaries on a consolidated basis. In certain circumstances, our subsidiaries are specifically referenced in order to distinguish among their different business activities.

The consolidated financial statements include the accounts of Ameren Corporation and its majority-owned subsidiaries. All significant intercompany transactions have been eliminated. The financial results of CILCORP have not been included or discussed in these financial statements, except with regard to certain forward looking information. All tabular dollar amounts are in millions, unless otherwise indicated.

The accounting policies of Ameren conform to generally accepted accounting principles in the United States (GAAP). Our financial statements reflect all adjustments (which include normal, recurring adjustments) necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from those estimates. Certain reclassifications have been made to prior years' financial statements to conform to 2002 reporting.

Regulation

We are subject to regulation by the Securities and Exchange Commission (SEC). Certain of Ameren's subsidiaries are also regulated by the Missouri Public Service Commission (MoPSC), Illinois Commerce Commission (ICC), Nuclear Regulatory Commission (NRC) and the Federal Energy Regulatory Commission (FERC). See Note 2 – Rate and Regulatory Matters for further information.

In accordance with Statement of Financial Accounting Standards (SFAS) No. 71 "Accounting for the Effects of Certain Types of Regulation," we defer certain costs pursuant to actions of our regulators and are currently recovering such costs in rates charged to customers.

At December 31, 2002 and 2001, we had the following regulatory assets and regulatory liabilities:

	2002	2001
Regulatory assets:		
Income taxes (a)(g)	$526	$604
Callaway costs (b)	81	84
Unamortized loss on reacquired debt (c)(g)	32	28
Recoverable costs–		
contaminated facilities (d)(g)	26	26
Other (e)(g)	25	29
Regulatory assets	$690	$771
Regulatory liabilities:		
Income taxes (f)	$136	$172

(a) See Note 11 - Income Taxes for amortization period. Amount represents SFAS 109 deferred tax asset.

(b) Represents Callaway nuclear plant operations and maintenance expenses, property taxes and carrying costs incurred between the plant in-service date and the date the plant was reflected in rates. These costs are being amortized over the remaining life of the plant's current operating license through 2024.

(c) Represents losses related to refunded debt. These amounts are being amortized over the lives of the related new debt issues or the remaining lives of the old debt issues if no new debt was issued.

(d) Represents the recoverable portion of accrued environmental site liabilities, which is primarily collected through a revenue rider in Illinois.

(e) Represents Y2K expenses being amortized over 6 years starting in 2002 in conjunction with the settlement of our Missouri electric rate case and a Department of Energy Decommissioning assessment being amortized over 14 years through 2007. In addition, amount includes the portion of merger-related expenses applicable to the Missouri retail jurisdiction, which are being amortized through 2008 based on a MoPSC order.

(f) See Note 11- Income Taxes for amortization period. Represents unamortized portion of investment tax credit and federal excess taxes.

(g) These assets do not earn a return.

We continually assess the recoverability of our regulatory assets. Under current accounting standards, regulatory assets are written off to earnings when it is no longer probable that such amounts will be recovered through future revenues. Electric industry restructuring legislation may impact the recoverability of regulatory assets in the future.

Property and Plant

The cost of additions to, and betterments of, units of property and plant is capitalized. Cost includes labor, material, applicable taxes and overheads. An allowance for funds used during construction is also added for our rate-regulated assets, and interest during construction is added for non rate-regulated assets. Maintenance expenditures and the renewal of items not considered units of property are expensed as incurred. When units of depreciable property are retired, the original cost and removal cost, less salvage value, are charged to accumulated depreciation. See Accounting Changes and Other Matters relating to SFAS No. 143 "Accounting for Asset Retirement Obligations" and Note 4 – Property and Plant, Net for further information.

Depreciation

Depreciation is provided over the estimated lives of the various classes of depreciable property by applying composite rates on a straight-line basis. The provision for depreciation in 2002, 2001, and 2000 was approximately 3% of the average depreciable cost.

Allowance for Funds Used During Construction

Allowance for funds used during construction (AFC) 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 rate-regulated construction expenditures are capitalized as a cost of construction. AFC does not represent a current source of cash funds. 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.

Under accepted ratemaking practice, cash recovery of AFC, as well as other construction costs, occurs when completed projects are placed in service and reflected in customer rates. The AFC ranges of rates used were 5% - 9% during 2002, 4% - 10% during 2001, and 6% - 10% during 2000.

Impairment of Long-Lived Assets

We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared with the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for loss if the carrying value is greater than the fair value. See Accounting Changes and Other Matters relating to SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets."

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an original maturity of three months or less.

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues.

Revenue

We accrue an estimate of electric and gas revenues for service rendered, but unbilled, at the end of each accounting period.

Interchange revenues included in Operating Revenues - Electric were $200 million for the year ended December 31, 2002 (2001 - $309 million, 2000 - $477 million). See Emerging Issues Task Force (EITF) Issue 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," discussion under Accounting Changes and Other Matters for further information.

Purchased Power

Purchased power included in Operating Expenses - Fuel and Purchased Power was $116 million for the year ended December 31, 2002 (2001 - $290 million, 2000 - $358 million). See EITF 02-3 discussion under Accounting Changes and Other Matters for further information.

Fuel and Gas Costs

In our retail electric utility jurisdictions, there are no provisions for adjusting rates for changes in the cost of fuel for electric generation. In our retail gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through purchased gas adjustment clauses.

The cost of nuclear fuel is amortized to fuel expense on a unit-of-production basis. Spent fuel disposal cost is charged to expense, based on net kilowatthours generated and sold.

Excise Taxes

Excise taxes on Missouri electric and gas, and Illinois gas customer bills are imposed on us and are recorded gross in Operating Revenues and Other Taxes. Excise taxes recorded in Operating Revenues and Other Taxes for 2002 were $116 million (2001- $113 million, 2000 - $119 million). Excise taxes applicable to Illinois electric customer bills are imposed on the consumer and are recorded as tax collections payable and included in Taxes Accrued on the Consolidated Balance Sheet.

Income Taxes

We file a consolidated federal tax return. 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 related properties.

Earnings Per Share

The inclusion of assumed stock option conversions in the calculation of earnings per share resulted in dilution of $0.01 for 2002 and 2001. There was no difference between the basic and diluted earnings per share amounts in 2000. Dilution resulted from assumed stock option conversions, which increased the number of shares outstanding in the diluted earnings per share calculation by 332,909 shares in 2002, 331,813 shares in 2001 and 183,201 shares in 2000.

Accounting Changes and Other Matters

In January 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The impact of that adoption resulted in a cumulative effect charge of $7 million, net of taxes, to the income statement, and a cumulative effect adjustment of $11 million net of taxes, to Accumulated Other Comprehensive Income (OCI), which reduced common stockholders' equity. See Note 3 – Derivative Financial Instruments for further information.

In January 2002, we adopted SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS 141 requires business combinations to be accounted for under the purchase method of accounting, which requires one party in the transaction to be identified as the acquiring enterprise and for that party to allocate the purchase price to the assets and liabilities of the acquired enterprise based on fair market value. SFAS 142 requires goodwill and indefinite-lived intangible assets recorded in the financial statements to be tested for impairment at least annually, rather than amortized over a fixed period, with impairment losses recorded in the income statement. SFAS 141 and SFAS 142 did not have any effect on our financial position, results of operations or liquidity upon adoption. SFAS 141 and SFAS 142 were utilized for our acquisition of CILCORP, Inc. and AES Medina Valley Cogen (No. 4), LLC. See Note 18 – Subsequent Event for further information.

We are adopting SFAS 143 in the first quarter of 2003. SFAS 143 provides the accounting requirements for asset retirement obligations associated with tangible, long-lived assets. SFAS 143 requires us to record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and to capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

Upon adoption of this standard, we expect to recognize additional asset retirement obligations of approximately $220 million and a net increase in net property and plant of approximately $75 million related primarily to the Callaway nuclear decommissioning costs and also to retirement costs for a river structure and an ash pond. These asset retirement obligations are in addition to liabilities we have previously recorded related to our future obligation to decommission the Callaway nuclear plant.

The difference between the net asset and the liability recorded upon adoption of SFAS 143 related to rate-regulated assets will be recorded as an additional regulatory asset because we expect to continue to recover the cost of Callaway nuclear decommissioning and other costs of removal in electric rates. The difference between the net asset and the liability to be recorded upon adoption related to non rate-regulated assets will be recorded as a loss of approximately $2 million, net of taxes, for a change in accounting principle.

In addition to these obligations, we have determined that certain other asset retirement obligations exist. However, we are unable to estimate the fair value of those obligations because the probability, timing or cash flows associated with the obligations are indeterminable. We do not believe that these obligations, when incurred, will have a material adverse impact on our financial position, results of operations or liquidity.

SFAS 143 also requires a change in the depreciation methodology we have historically utilized for our non rate-regulated operations. Historically, we have included an estimated cost of dismantling and removing plant from service upon retirement in the basis upon which our depreciation rates were determined. SFAS 143 requires us to exclude costs of dismantling and removal upon retirement from the depreciation rates applied to non rate-regulated plant balances. Further, we are required to remove accumulated provisions for dismantling and removal costs from accumulated depreciation, where they are currently embedded, and reflect such adjustment as a gain upon adoption of this standard, to the extent such dismantling and removal activities are not considered obligations as defined by SFAS 143. At this time we have not finalized our determination of the gain to be recorded upon adoption of SFAS 143 for our non rate-regulated operations; however, it will most likely substantially exceed the loss resulting from adopting this standard discussed above. Additionally, beginning in January 2003, depreciation rates for non rate-regulated assets will be reduced to reflect the discontinuation of the accrual of dismantling and removal costs. As a result, non rate-regulated asset removal costs will be expensed as incurred. The impact of this change in accounting will result in a decrease in depreciation expense and an increase in operations and maintenance expense, the net impact of which is indeterminable, but not expected to be material.

Like our non rate-regulated operations, the depreciation methodology historically utilized by our rate-regulated operations has included an estimated cost of dismantling and removing plant from service upon retirement. This practice is currently required by regulators in the jurisdictions in which we operate. As a result, though we are still assessing the impact of SFAS 143 on our rate-regulated depreciation methodology, we do not believe any such impact will affect our results of operations. However, if we are required to remove accrued dismantling and removal costs from accumulated depreciation, where they are currently embedded, our asset and liability balances could be materially increased.

On January 1, 2002, we adopted SFAS 144. SFAS 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS 144 retains the guidance related to calculating and recording impairment losses but adds guidance on the accounting for discontinued operations, previously accounted for under Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations – Reporting the Effects of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." SFAS 144 did not have any effect on our financial position, results of operations or liquidity in 2002.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 requires an entity to recognize, and measure at fair value, a liability for a cost associated with an exit or disposal activity in the period in which the liability is incurred and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." SFAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002.

During 2002, we adopted the provisions of EITF 02-3, that required revenues and costs associated with certain energy contracts to be shown on a net basis in the income statement. Prior to adopting EITF 02-3 and the rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," our accounting practice was to present all settled energy purchase or sales contracts within our power risk management program, on a gross basis in Operating Revenues – Electric and in Operating

Expenses – Fuel and Purchased Power. This meant that revenues were recorded for the notional amount of the power sale contracts with a corresponding charge to income for the costs of the energy that was generated, or for the notional amount of a purchased power contract.

In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. The effective date for the full rescission of EITF 98-10 was for fiscal periods beginning after December 15, 2002, with early adoption permitted. In addition, the EITF reached a consensus in October 2002 that all SFAS 133 trading derivatives (subsequent to the rescission of EITF 98-10) should be shown net in the income statement, whether or not physically settled. This consensus applies to all energy and non-energy related trading derivatives that meet the definition of a derivative pursuant to SFAS 133. We have adopted and applied this guidance to 2002 and 2001. The adoption of EITF 02-3, the rescission of EITF 98-10 and the related transition guidance resulted in netting of certain energy contracts, and lowered our reported revenues and costs with no impact on earnings or stockholders' equity. The following table summarizes the impact of energy contract netting for the years ended December 31, 2001 and 2000:

	2001	2000
Previously reported gross operating revenues	$4,506	$3,856
Revenues and costs netted (a)	648	–
Net operating revenues reported	$3,858	$3,856

(a) Revenues and costs netted for the year ended December 31, 2002 were $738 million. SFAS 133 was adopted on January 1, 2001 and therefore no netting was required for the year ended December 31, 2000.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." SFAS 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions to require disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation.

Prior to 2003, we accounted for our long-term incentive plan under the recognition and measurement provisions of APB Opinion No. 25, "Accounting for Stock Issued to Employees." No stock-based employee compensation cost was reflected for options in 2002, 2001, and 2000 as all options granted under our plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The pretax effect of weighted-average grant-date fair value of options granted would have been approximately $2 million in each of the years ended 2002, 2001, and 2000 had the fair value method under SFAS 123 been used for options. Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS 123 by using the prospective method of adoption under SFAS 148. We do not expect SFAS 148 to have any effect on our financial position, results of operations or liquidity in 2003. See Note 13 – Stock-Based Compensation for further information.

NOTE 2 – RATE AND REGULATORY MATTERS

Missouri Electric

MoPSC Rate Case

From July 1, 1995 through June 30, 2001, our subsidiary, AmerenUE, operated under experimental alternative regulation plans in Missouri that provided for the sharing of earnings with customers if our regulatory return on equity exceeded defined threshold levels. After AmerenUE's experimental alternative regulation plan for its Missouri retail electric customers expired, the MoPSC Staff and others sought to reduce our annual Missouri electric revenues by over $300 million. The MoPSC Staff's recommendation was based on a return to traditional cost of service ratemaking, a lowered return on equity, a reduction in AmerenUE's depreciation rates and other cost of service adjustments.

In August 2002, a stipulation and agreement resolving this case became effective following agreement by all parties to the case and approval by the MoPSC. The stipulation and agreement includes the following principal features:

- The phase-in of $110 million of electric rate reductions through April 2004, $50 million of which was retroactively effective as of April 1, 2002, $30 million of which will become effective on April 1, 2003, and $30 million of which will become effective on April 1, 2004.
- A rate moratorium providing for no changes in rates before June 30, 2006, subject to certain statutory and other exceptions.
- A commitment to contribute $14 million to programs for low income energy assistance and weatherization, promotion of energy efficiency and economic development in AmerenUE's service territory in 2002, with additional payments of $3 million made annually on

June 30, 2003 through June 30, 2006. This entire obligation was expensed in 2002.

- A commitment to make $2.25 billion to $2.75 billion in critical energy infrastructure investments from January 1, 2002 through June 30, 2006, including, among other things, the addition of more than 700 megawatts of new generation capacity and the replacement of steam generators at AmerenUE's Callaway nuclear plant. The 700 megawatts of new generation is expected to be satisfied by 240 megawatts that were added by AmerenUE in 2002 and the proposed transfer at net book value to AmerenUE of approximately 550 megawatts of generation assets from Generating Company, which is subject to receipt of necessary regulatory approvals.
- An annual reduction in AmerenUE's depreciation rates by $20 million, retroactive to April 1, 2002, based on an updated analysis of asset values, service lives and accumulated depreciation levels.
- A one-time credit of $40 million which was accrued during the plan period. The entire amount was paid to AmerenUE's Missouri retail electric customers in 2002 for settlement of the final sharing period under the alternative regulation plan that expired June 30, 2001.

Marketing Company – AmerenUE Power Supply Agreements

In order to satisfy AmerenUE's regulatory load requirements for 2001, AmerenUE purchased, under a one year contract (the 2001 Marketing Company - AmerenUE agreement), 450 megawatts of capacity and energy from Marketing Company. This agreement was entered into through a competitive bidding process and reflected market-based rates. For 2002, AmerenUE similarly entered into a one year contract (the 2002 Marketing Company - AmerenUE agreement) with Marketing Company for the purchase of 200 megawatts of capacity and energy. For the four summer months of 2002, AmerenUE also entered into contracts with two other power suppliers for an aggregate 200 megawatts of additional capacity and energy.

In May 2001, the MoPSC filed a complaint with the SEC relating to the 2001 Marketing Company - AmerenUE agreement. The complaint requested an investigation into the contractual relationship between AmerenUE, Marketing Company and Generating Company, in the context of the 2001 Marketing Company - AmerenUE agreement and requested that the SEC find that such relationship violates Section 32(k) of PUHCA, which requires state utility commission approval of power sales contracts between an electric utility company and an affiliated exempt wholesale generator, like Generating Company. We have asserted that the MoPSC's approval of the power sales agreement under PUHCA is not required because Generating Company is not a party to the agreement. In its SEC complaint, the MoPSC proposes that the SEC require AmerenUE to contract directly with Generating Company and submit such contract to the MoPSC for review. On May 9, 2002, the MoPSC filed a similar complaint with the SEC relating to the 2002 Marketing Company - AmerenUE agreement. While the complaints were pending, the MoPSC and AmerenUE reached an agreement for resolving these disputes. The agreement requires AmerenUE to not enter into any new contracts to purchase wholesale electric energy from any Ameren affiliate that is an exempt wholesale generator without first obtaining, on a timely basis, the determinations required of the MoPSC that are specified in Section 32(k) of PUHCA. However, this commitment did not prevent AmerenUE from completing the purchases contemplated by the 2001 and 2002 Marketing Company – AmerenUE agreement and does not prevent AmerenUE from making short term energy purchases (less than 90 days) from an Ameren affiliate, without prior MoPSC determination, to prevent or alleviate system emergencies. As part of this agreement, the MoPSC has agreed to terminate its SEC complaints.

Also, with respect to the 2002 Marketing Company – AmerenUE agreement, on May 31, 2002, the FERC accepted the agreement, subject to refund, and scheduled the matter for a January 2003 hearing. In October 2002, Marketing Company and the FERC Staff jointly reported to the FERC that they have negotiated a settlement in principle of the issues that had been set for hearing. Other than a slight modification to the procedures for establishing off-peak energy prices under the agreement, the settlement in principle will have no impact on the agreement's price, terms and conditions. The settlement in principle also establishes guidelines for AmerenUE to follow when conducting future requests for proposals for the purpose of pursuing long-term power purchases. On January 27, 2003, the settlement in principle between Marketing Company and the FERC Staff was certified by the settlement judge and submitted to the FERC for approval.

Until the SEC and the FERC take final action in these proceedings, management is unable to predict their ultimate impact on our future financial position, results of operations or liquidity.

Illinois Electric

In 2002, all of our Illinois residential, commercial and industrial customers had choice in electric suppliers.

As a provision of the legislation related to the restructuring of the Illinois electric industry (the Illinois Law), a rate freeze is in effect through January 1, 2007. As a result of this extension through January 1, 2007, we expect to seek to renew or extend a power supply agreement between AmerenCIPS and Marketing Company through the same period. A renewal or extension of the power supply agreement will depend on compliance with regulatory requirements in effect at the time, and we cannot predict whether we will be successful in securing a renewal or extension of this agreement.

In October 2002, AmerenUE and AmerenCIPS filed with the ICC a proposal to suspend collection of transition charges associated with the Illinois Law for the period commencing June 2003 until at least June 2005. The Illinois Law allows a utility to collect transition charges from customers that elect to move from bundled retail rates to market-based rates. Utilities have the right to collect transition charges throughout the transition period that ends January 1, 2007. The suspension of collection of transition charges is not expected to have a material impact on either AmerenUE or AmerenCIPS.

Under the Illinois Law, we were subject to a residential electric rate decrease of up to 5% in 2002 to the extent rates exceeded the Midwest utility average. In 2002, 2001, and 2000, our Illinois electric rates were below the Midwest utility average.

The Illinois Law also contains a provision requiring that one-half of excess earnings from the Illinois jurisdiction for the years 1998 through 2006 be refunded to Ameren's Illinois customers. Excess earnings are defined as the portion of the two-year average annual rate of return on common equity in excess of 1.5% of the two-year average of an Index, as defined in the Illinois Law. The Index is defined as the sum of the average for the twelve months ended September 30 of the average monthly yields of the 30-year U.S. Treasury bonds, plus prescribed percentages ranging from 4% to 7%. AmerenCIPS' and AmerenUE's average rates of return on common equity for the two year average at December 31, 2002 were 6% and 13%, respectively, as compared to the average index of 12.6%. No refunds are expected to be required for the period of April 1, 2002 through March 31, 2003. For the twelve months ended December 31, 1999, AmerenUE made excess earnings refunds of $2.1 million from April 1, 2000 through March 31, 2001. For the twelve months ended December 31, 2000, AmerenUE made excess earnings refunds of $1.5 million from April 1, 2001 through May 31, 2002. These refunds were recorded as a reduction to Operating Revenues – Electric.

Federal – Electric Transmission

Regional Transmission Organization

In December 1999, the FERC issued Order 2000 requiring all utilities, subject to FERC jurisdiction, to state their intentions for joining a regional transmission organization (RTO). RTOs are independent organizations that will functionally control the transmission assets of utilities and are designed to improve the wholesale power market. Beginning in January 2001, our subsidiaries, AmerenUE and AmerenCIPS, along with several other utilities, sought approval from the FERC to participate in an RTO known as the Alliance RTO. The Ameren companies had previously been members of the Midwest Independent System Operator (Midwest ISO) and recorded a pretax charge to earnings in 2000 of $25 million ($15 million, net of taxes) for an exit fee and other costs when we left that organization. We believed that the for-profit Alliance RTO business model was superior to the not-for-profit Midwest ISO business model and provided us with a more equitable return on our transmission assets.

In late 2001, the FERC issued an order that rejected the formation of the Alliance RTO and ordered the Alliance RTO companies and the Midwest ISO to discuss how the Alliance RTO business model could be accommodated within the Midwest ISO. In April 2002, after the Alliance RTO and Midwest ISO failed to reach an agreement, and after a series of filings by the two parties with the FERC, the FERC issued a declaratory order setting forth the division of responsibilities between the Midwest ISO and National Grid (the managing member of the transmission company formed by the Alliance companies) and approved the rate design and the revenue distribution methodology proposed by the Alliance companies. However, the FERC denied a request by the Alliance companies and National Grid to purchase certain services from the Midwest ISO at incremental cost rather than Midwest ISO's full tariff rates. The FERC also ordered the Midwest ISO to return the exit fee paid by the Ameren companies to leave the Midwest ISO, provided the Ameren companies return to the Midwest ISO and agree to pay their proportional share of the startup and ongoing operational expenses of the Midwest ISO. Moreover, the FERC required the Alliance companies to select the RTO in which they will participate within thirty days of the order.

Following the April 2002 FERC order, Ameren made filings with the FERC indicating that Ameren would return to the Midwest ISO through a new independent transmission company, GridAmerica LLC, that was agreed to be formed by AmerenCIPS and AmerenUE, and subsidiaries of FirstEnergy Corporation and NiSource Inc. Upon receipt of final FERC approval of the definitive agreements establishing GridAmerica, a subsidiary of National Grid will serve as the managing member of

GridAmerica and will manage the transmission assets of the three companies and participate in the Midwest ISO on behalf of GridAmerica. Other Alliance RTO companies announced their intentions to join the PJM Interconnection LLC (PJM) RTO. On July 25, 2002, the Ameren companies filed a motion with the FERC requesting that it condition the approval of the choices of other Illinois utilities to join the PJM RTO on Midwest ISO and PJM entering into an agreement addressing important reliability and rate-barrier issues. On July 31, 2002, the FERC issued an order accepting the formation of GridAmerica as an independent transmission company under the Midwest ISO subject to further compliance filings ordered by the FERC. The FERC also issued an order accepting the elections made by the other Illinois utilities to join the PJM RTO on the condition PJM and Midwest ISO immediately begin a process to address the reliability and rate-barrier issues raised by us and other market participants in previous filings.

The compliance filing to facilitate the formation and operation of GridAmerica as an independent transmission company within the Midwest ISO, as contemplated in the July 31, 2002 order of the FERC, was conditionally accepted by FERC in an order issued December 19, 2002. In the order, the FERC approved the return of the $18 million exit fee paid by Ameren to leave the Midwest ISO with interest once GridAmerica becomes operational. The FERC also approved, subject to further filings, reimbursement of $36 million to the GridAmerica companies for expenses incurred to form the Alliance RTO. In our filing, we stated that GridAmerica is scheduled to become operational in April 2003.

Until the reliability and rate-barrier issues are resolved as ordered by the FERC, and the tariffs and other material terms of our participation in GridAmerica, and GridAmerica's participation in the Midwest ISO, are finalized and approved by the FERC, we are unable to predict the impact that on-going RTO developments will have on our financial position, results of operations or liquidity.

Standard Market Design Notice of Proposed Rulemaking (NOPR)

On July 31, 2002, the FERC issued a NOPR. The NOPR proposes a number of changes to the way the current wholesale transmission service and energy markets are operated. Specifically, the NOPR calls for all jurisdictional transmission facilities to be placed under the control of an independent transmission provider (similar to an RTO), proposes a new transmission service tariff that provides a single form of transmission service for all users of the transmission system including bundled retail load, and proposes a new energy market and congestion management system that uses locational marginal pricing as its basis. On November 15, 2002, we filed our initial comments on the NOPR with the FERC expressing our concern with the potential impact of the proposed rules in their current form on the cost and reliability of service to retail customers. We also proposed that certain modifications be made to the proposed rules in order to protect transmission owners from the possibility of trapped transmission costs that might not be recoverable from ratepayers as a result of inconsistent regulatory policies. We intend to file additional comments on the remaining sections of the NOPR during the first quarter of 2003. Until the FERC issues a final rule, we are unable to predict the ultimate impact on our future financial position, results of operations or liquidity.

Illinois Gas

In November 2002, AmerenCIPS, AmerenUE, and CILCO filed requests with the ICC to increase annual rates for natural gas service by approximately $16 million, $4 million, and $14 million, respectively. The ICC has until October 2003 to render a decision in these gas cases.

NOTE 3 – DERIVATIVE FINANCIAL INSTRUMENTS

We utilize derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause:

- an unrealized appreciation or depreciation in the value of our firm commitments to purchase or sell when purchase or sales prices under the firm commitment are compared with current commodity prices;
- market values of fuel and natural gas inventories or purchased power to differ from the cost of those commodities in inventory or under the firm commitment; and
- actual cash outlays for the purchase of these commodities, in certain circumstances, to differ from anticipated cash outlays.

The derivatives that we use to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. We continually assess our supply and delivery commitment positions against forward market prices and internal forecasts of forward prices. We actively manage our exposure to power price risk through our power risk management program carried out under our risk management guidelines to modify our exposure to market, credit and operational risk by entering into various offsetting transactions. In general, we believe these transactions serve to reduce price risk for us.

In addition, we may purchase additional power, again within risk management guidelines, in anticipation of power requirements and future price changes. Certain derivative contracts we enter into on a regular basis as part of our power risk management program do not qualify for hedge accounting or the normal purchase and sale exceptions under SFAS 133. Accordingly, these contracts are recorded at fair value with changes in the fair value charged or credited to the income statement in the period in which the change occurred. Contracts we enter into as part of our power risk management program may be settled by either physical delivery or net settled with the counterparty. See also Note 1 – Summary of Significant Accounting Policies for further information.

As of December 31, 2002, we recorded the fair value of derivative financial instrument assets of $8 million in Other Assets and the fair value of derivative financial instrument liabilities of $1 million in Other Deferred Credits and Liabilities.

Cash Flow Hedges

We routinely enter into forward purchase and sales contracts for electricity based on forecasted levels of economic generation and customer requirements. The relative balance between customer requirements and economic generation varies throughout the year. The contracts typically cover a period of twelve months or less. The purpose of these contracts is to hedge against possible price fluctuations in the spot market for the period covered under the contracts. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objective and strategy for undertaking various hedge transactions. The mark-to-market value of cash flow hedges will continue to fluctuate with changes in market prices up to contract expiration.

The pretax net gain or loss on power forward derivative instruments, which represented the impact of discontinued cash flow hedges, the ineffective portion of cash flow hedges, as well as the reversal of amounts previously recorded in OCI due to transactions going to delivery or settlement, was approximately a $3 million loss for the year ended December 31, 2002 (2001 - $15 million gain).

As of December 31, 2002, we had hedged a portion of the electricity price exposure for the upcoming twelve-month period. The mark-to-market value accumulated in OCI for the effective portion of hedges of electricity price exposure was a net gain of approximately $1 million (less than $1 million, net of taxes).

As of December 31, 2002, a gain of approximately $6 million ($4 million, net of taxes) associated with interest rate swaps was included in OCI. The swaps were a partial hedge of the interest rate on debt that was issued in June 2002. The swaps covered the first ten years of debt that has a 30-year maturity and the gain in OCI is being amortized over a ten-year period that began in June 2002.

As of December 31, 2002, a gain of approximately $2 million ($1 million, net of taxes) associated with natural gas swaps was included in OCI. The swaps were a partial hedge of our index priced, baseload gas supply for the period of December 2002 through March 2003. The swaps effectively fix the price on a portion of our gas supply for that time period.

We also held three call options for coal with two suppliers. These options to purchase coal expire October 2003, July 2004 and July 2005. As of December 31, 2002, a mark-to-market gain of approximately $6 million ($4 million, net of taxes) associated with these options was included in OCI. The final value of the options will be recognized as a reduction in fuel costs as the hedged coal is burned.

Other Derivatives

We enter into option transactions to manage our positions in sulfur dioxide allowances, coal, heating oil and electricity. Most of these transactions are treated as non-hedge transactions under SFAS 133. The net change in the market value of sulfur dioxide options is recorded as Operating Revenues - Electric, while the net change in the market value of coal, heating oil and electricity options is recorded as Operating Expense – Operations - Fuel and Purchased Power in the income statement. The net change in the market values of sulfur dioxide, coal, heating oil and electricity options was a gain of $5 million ($3 million, net of taxes) for the year ended December 31, 2002 (2001 - loss of less than $1 million).

NOTE 4 – PROPERTY AND PLANT, NET

At December 31, 2002 and 2001, property and plant, net consisted of the following:

	2002	2001
Property and plant, at original cost:		
Electric	$14,495	$13,664
Gas	557	532
Other	219	105
	15,271	14,301
Less accumulated depreciation and amortization	6,831	6,535
	8,440	7,766
Construction work in progress:		
Nuclear fuel in process	81	97
Other	393	564
Property and plant, net	$ 8,914	$ 8,427

NOTE 5 – NUCLEAR FUEL LEASE

We have a lease agreement, expiring on August 31, 2031, that provides for the financing of a portion of our nuclear fuel that is being processed for use or being consumed in AmerenUE's Callaway nuclear plant. The lease agreement has variable interest rates based on short-term commercial paper interest rates. At December 31, 2002, the maximum amount that could be financed under the agreement was $120 million, of which $113 million was utilized. The lessor, Gateway Fuel Company, maintains a $120 million committed credit facility which supports the financing of fuel under the lease. We consider available lease capacity, future purchase commitments and upcoming in-service fuel requirements when determining whether to utilize leased nuclear fuel. We are not required to pay the lessor, an unrelated third party, unless nuclear fuel is removed from the lease, consumed at our nuclear plant or the lease is terminated. Pursuant to the terms of the lease, we assign to the lessor certain contracts for purchase of nuclear fuel. The lessor obtains, through the issuance of commercial paper or from direct loans under a committed revolving credit agreement from commercial banks, the necessary funds to purchase the fuel and make interest payments when due.

We are obligated to reimburse the lessor for expenditures for nuclear fuel, interest and related costs under the lease. As any leased nuclear fuel is consumed at AmerenUE's Callaway nuclear plant, obligations under this lease become due. No leased nuclear fuel was consumed in 2001. Therefore, no reimbursements for amounts consumed under the lease occurred in 2001. Leased nuclear fuel consumption re-commenced in the fourth quarter of 2002. The corresponding reimbursement will occur in the first quarter of 2003. We reimbursed $13 million during 2000 for amounts consumed under the lease.

We have capitalized the cost of the leased nuclear fuel incurred by the lessor, plus certain interest costs, and have recorded the related lease obligation. Total interest charges under the lease were $2 million in 2002, $4 million in 2001, and $8 million in 2000. Interest charges for these years were based on average interest rates of approximately 2% for 2002, 5% for 2001 and 7% for 2000. Interest charges of $2 million in 2002, $4 million in 2001, and $6 million in 2000 were capitalized.

NOTE 6 – SHAREHOLDER RIGHTS PLAN AND PREFERRED STOCK SUBSIDIARIES

In October 1998, our Board of Directors approved a share purchase rights plan designed to assure shareholders of fair and equal treatment in the event of a proposed takeover. The rights will be exercisable only if a person or group acquires 15% or more of Ameren's common stock or announces a tender offer, the consummation of which would result in ownership by a person or group of 15% or more of the common stock. Each right will entitle the holder to purchase one one-hundredth of a newly issued preferred stock at an exercise price of $180. If a person or group acquires 15% or more of Ameren's outstanding common stock, each right will entitle its holder (other than such person or members of such group) to purchase, at the right's then-current exercise price, a number of Ameren's common shares having a market value of twice such price. In addition, if we are acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of our outstanding common stock, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of the acquiring company's common shares having a market value of twice such price. The acquiring person or group will not be entitled to exercise these rights. The SEC approved the plan under PUHCA in December 1998. The rights were issued as a dividend payable January 8, 1999, to shareholders of record on that date; these rights expire in 2008. One right will accompany each new share of Ameren common stock issued prior to such expiration date.

Outstanding preferred stock is entitled to cumulative dividends and is redeemable, at the option of the issuer, at the prices shown in the following table as of December 31, 2002 and 2001:

	Shares	Redemption Price (Per Share)	2002	2001
Preferred stock of subsidiaries not subject to mandatory redemption –				
AmerenUE:				
Without par value and stated value of $100 per share, 25 million shares authorized				
$7.64 Series	330,000	$103.82 (a)	$ 33	$ 33
$5.50 Series A	14,000	110.00	1	1
$4.75 Series	20,000	102.176	2	2
$4.56 Series	200,000	102.47	20	20
$4.50 Series	213,595	110.00 (b)	21	21
$4.30 Series	40,000	105.00	4	4
$4.00 Series	150,000	105.625	15	15
$3.70 Series	40,000	104.75	4	4
$3.50 Series	130,000	110.00	13	13
Without par value and stated value of $25 per share				
$1.735 Series	1,657,500	25.00	–	42

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	Shares	Redemption Price (Per Share)	December 31, 2002	2001
AmerenCIPS:				
With par value of $100 per share,				
4.6 million shares authorized				
4.00% Series	150,000	$101.00	$ 15	$ 15
4.25% Series	50,000	102.00	5	5
4.90% Series	75,000	102.00	8	8
4.92% Series	50,000	103.50	5	5
5.16% Series	50,000	102.00	5	5
1993 Auction	300,000	100.00 (c)	30	30
6.625% Series	125,000	100.00	12	12
Total preferred stock of subsidiaries not subject to mandatory redemption			$193	$235

(a) Beginning February 15, 2003, declining to $100 per share in 2012.

(b) In the event of voluntary liquidation, $105.50.

(c) Dividend rates, and the periods during which such rates apply, vary depending on our selection of certain defined dividend period lengths. The average dividend rate during 2002 was 2.35%.

NOTE 7 – SHORT-TERM BORROWINGS

Our short-term borrowings consist of commercial paper and bank loans (maturities generally within 1 to 45 days). At December 31, 2002, $271 million (2001 - $641 million) of short-term borrowings was outstanding. The weighted average interest rate on short-term borrowings outstanding at December 31, 2002 was 1.4% (2001 – 1.9%).

At December 31, 2002, Ameren had bank credit agreements totaling $695 million, excluding EEI facilities of $45 million and nuclear fuel lease facilities of $21 million, expiring at various dates in 2003 and 2005. All of these amounts were available for use by our rate-regulated subsidiaries (AmerenUE and AmerenCIPS) and Ameren Services Company, and $600 million of this amount was available for use by Ameren Corporation and most of our non rate-regulated subsidiaries including, but not limited to, Resources Company, Generating Company, Marketing Company, AmerenEnergy Fuels and Services Company and AmerenEnergy. These committed credit facilities are used to support our commercial paper programs under which $250 million was outstanding at December 31, 2002. At December 31, 2002, $445 million was unused and available under these committed credit facilities.

We also have two bank credit agreements totaling $45 million that expire in 2003 at EEI. At December 31, 2002, $27 million was unused and available under these committed credit facilities.

Certain of our bank credit agreements contain provisions which, among other things, place restrictions on our ability to incur liens, sell assets, merge with other entities and restrict and encumber upstream dividend payments of our subsidiaries. Also, certain of our credit agreements contain a provision that restricts Ameren's, AmerenUE's and AmerenCIPS' total indebtedness to 60% of total capitalization. In addition, certain of our credit agreements contain cross default provisions and material adverse change clauses, which require us to represent that no such change has occurred before borrowings can be made. At December 31, 2002, Ameren, AmerenUE and AmerenCIPS were in compliance with all such provisions.

We have money pool agreements with and among our subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained between rate-regulated and non rate-regulated businesses. Interest is calculated at varying rates of interest depending on the composition of internal and external funds in the money pools. This debt and the related interest represent inter-company balances, which are eliminated at the Ameren Corporation consolidated level.

NOTE 8 – LONG-TERM DEBT AND CAPITALIZATION

The following table summarizes our long-term debt outstanding at December 31, 2002 and 2001:

		2002	2001
First mortgage bonds – (a)			
AmerenUE:			
8.33%	Series paid in 2002	$ –	$ 75
8 ¾%	Series paid in 2002	–	125
7.65%	Series due 2003	100	100
6 ⅞%	Series due 2004	188	188
7 ⅜%	Series due 2004	85	85
6 ¾%	Series due 2008	148	148
5.25%	Series due 2012	173	–
8 ¼%	Series due 2022	104	104
8%	Series due 2022	85	85
7.15%	Series due 2023	75	75
7%	Series due 2024	100	100
5.45%	Series due 2028 (b)	44	44
AmerenCIPS:			
6 ⅜%	Series Z due 2003	40	40
7 ½%	Series X due 2007	50	50
6.625%	Series due 2011	150	150
7.61%	1997 Series due 2017	40	40
6.125%	Series due 2028	60	60
Other 5.375% – 7.05% due 2003 through 2008		60	93
		$1,502	$1,562

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	December 31, 2002	December 31, 2001
Environmental improvement/ pollution control revenue bonds –		
AmerenUE:		
1991 Series due 2020 (c)	$ 43	$ 43
1992 Series due 2022 (c)	47	47
1998 Series A due 2033 (c)	60	60
1998 Series B due 2033 (c)	50	50
1998 Series C due 2033 (c)	50	50
2000 Series A due 2035 (c)	64	64
2000 Series B due 2035 (c)	63	63
2000 Series C due 2035 (c)	60	60
AmerenCIPS:		
2000 Series A 5.5% due 2014 (d)	51	51
1993 Series C-1 5.95% due 2026 (d)	35	35
1993 Series A 6 ⅜% due 2028	35	35
Other 5% – 5.90% due 2026 through 2028 (d)	60	60
	618	618
Subordinated deferrable interest debentures –		
AmerenUE:		
7.69% Series A due 2036 (e)	66	66
Other unsecured debt –		
Ameren Corporation:		
2001 Floating rate notes due 2003 (f)	150	150
2002 5.70% Notes due 2007 (g)	100	–
Senior note, due 2007	345	–
Generating Company:		
2000 Senior notes series C 7 ¾% due 2005 (h)(i)	225	225
2000 Senior notes series D 8.35% due 2010 (i)(j)	200	200
2002 Senior notes series F 7.95% due 2032 (i)(k)	275	–
Electric Energy, Inc.:		
2000 Senior notes 7.61% due 2004	40	40
1991 Senior medium term notes 8.60% due through 2005	20	27
1994 Senior medium term notes 6.61% due through 2005	23	31
	1,378	673
Capital lease obligations –		
AmerenUE:		
Nuclear fuel lease	113	63
City of Bowling Green lease	103	–
	216	63
Unamortized discount and premium on debt	(8)	(8)
Maturities due within one year	(339)	(139)
Total long-term debt	$3,433	$2,835

(a) At December 31, 2002, a majority of property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued. AmerenUE's and AmerenCIPS' first mortgage bond indentures contain provisions that restrict the issuance of additional bonds. These provisions restrict future first mortgage bond issuance to 60% of unused net bondable property and previously retired bonds. In addition, net earnings must be at least twice that of first mortgage bond interest to be able to issue bonds under the indentures. AmerenCIPS' indenture also requires a certain level of maintenance capital expenditures. At December 31, 2002, both AmerenUE and AmerenCIPS were in compliance with all such provisions.

(b) Environmental Improvement Series backed by first mortgage bonds.

(c) Interest rates, and the periods during which such rates apply, vary depending on our selection of certain defined rate modes. The average interest rates for the year 2002 were as follows:

1991 Series	*1.64%*
1992 Series	*1.60%*
1998 Series A	*1.53%*
1998 Series B	*1.53%*
1998 Series C	*1.53%*
2000 Series A	*1.56%*
2000 Series B	*1.52%*
2000 Series C	*1.56%*

(d) Variable rate tax-exempt pollution control indebtedness that was converted to long-term fixed rates.

(e) During the terms of the debentures, AmerenUE may, under certain circumstances, defer the payment of interest for up to five years. Upon the election to defer interest payments, dividend payments to Ameren Corporation are prohibited.

(f) Interest is payable quarterly commencing March 12, 2002. Principal is payable on December 12, 2003. The per annum interest rate on the notes for each interest period will be a floating rate equal to three month LIBOR plus a spread of 0.95%.

(g) Interest is payable semiannually in arrears on February 1 and August 1 of each year, commencing August 1, 2002. Principal will be payable on February 1, 2007.

(h) Interest is payable semiannually in arrears on May 1 and November 1 of each year, commencing May 1, 2001. Principal will be payable on November 1, 2005.

(i) Generating Company's senior note indenture contains covenants which, among other things, restrict dividend payments, subordinated debt interest payments and future bond issuance if certain financial conditions are not met. These conditions include minimum interest coverage ratios and a maximum debt to capital ratio. At December 31, 2002, Generating Company was in compliance with all such provisions.

(j) Interest is payable semiannually in arrears on May 1 and November 1 of each year, commencing May 1, 2001. Principal will be payable on November 1, 2010.

(k) Interest is payable semiannually in arrears on June 1 and December 1 of each year, commencing December 1, 2002. Principal will be payable on June 1, 2032.

The following table summarizes the maturities of long-term debt at December 31, 2002:

	Ameren Corporation	AmerenUE	AmerenCIPS
2003	$150	$ 130	$ 45
2004	–	306	–
2005	–	36	20
2006	–	27	20
2007	445	4	50
Thereafter	–	1,318	446
Total	$595	$1,821	$ 581

	Generating Company	Electric Energy, Inc.	Ameren Consolidated
2003	$ –	$ 14	$ 339
2004	–	55	361
2005	225	14	295
2006	–	–	47
2007	–	–	499
Thereafter	475	–	2,239
Total	$700	$ 83	$3,780

Ameren Corporation

In January 2002, Ameren Corporation issued $100 million of 5.70% notes due February 1, 2007 in a private placement to qualified investors under rule 144A. Ameren received net proceeds of $99.7 million, after debt discount and fees, which were used to reduce short-term borrowings. Interest is payable semi-annually on February 1 and August 1 of each year. In March 2002, Ameren Corporation entered into interest rate swaps effectively converting the interest rate associated with these notes to three month LIBOR plus 43 basis points. At December 31, 2002, the effective interest rate for these notes was 2.13%.

In March 2002, Ameren Corporation issued $345 million of adjustable conversion-rate equity security units and $227 million of common stock (5 million shares at $39.50 per share and 750,000 shares, pursuant to the exercise of an option granted to the underwriters, at $38.865 per share). The $25 adjustable conversion-rate equity security units each consisted of an Ameren Corporation senior unsecured note with a principal amount of $25 and a contract to purchase, for $25, a fraction of a share of Ameren common stock on May 15, 2005. The senior unsecured notes were recorded at their fair value of $345 million and will mature on May 15, 2007. Total distributions on the equity security units will be at an annual rate of 9.75%, consisting of quarterly interest payments on the senior unsecured notes at the initial annual rate of 5.20% and adjustment payments under the stock purchase contracts at the annual rate of 4.55%. The stock purchase contracts require holders to purchase between 8.7 million and 7.4 million shares of Ameren Corporation common stock on May 15, 2005 at the market price at that time, subject to a minimum share purchase price of $39.50 and a maximum of $46.61. The stock purchase contracts include a pledge of the senior unsecured notes as collateral for the stock purchase obligation. The interest rate on the outstanding senior unsecured notes is subject to being reset by a remarketing agent for quarterly payments after May 15, 2005 until maturity. We recorded the net present value of the contracted stock purchase payments of $46 million as an increase in Other Deferred Credits and Liabilities to reflect our obligation and a decrease in Other Paid-in Capital to reflect the fair value of the stock purchase contract. The liability for the contracted stock purchase adjustment payments (December 31, 2002 - $35 million) will be reduced as such payments are made through May 15, 2005. We used the net proceeds from these offerings to repay short-term indebtedness and for general corporate purposes.

In July 2002, Ameren Corporation entered into new committed credit agreements for $400 million in revolving credit facilities to be used for general corporate purposes, including support of our commercial paper programs. The $400 million in new facilities includes a $270 million 364-day revolving credit facility and a $130 million 3-year revolving credit facility. The 3-year facility has a $50 million sub-limit for the issuance of letters of credit. These new credit facilities replaced AmerenUE’s $300 million revolving credit facility.

In August 2002, a shelf registration statement filed by Ameren Corporation with the SEC on Form S-3 was declared effective. This statement authorized the offering from time to time of up to $1.473 billion of various forms of securities including long-term debt, trust preferred and equity securities to finance ongoing construction and maintenance programs, to redeem, repurchase, repay, or retire outstanding debt, to finance strategic investments, including our then pending acquisition of CILCORP, and for general corporate purposes.

In September 2002, Ameren Corporation issued, pursuant to the shelf registration statement, $338 million of common stock (8.05 million shares at $42.00 per share). Net proceeds were $327 million after fees, which were used to fund part of the cash portion of the purchase price for our acquisition of CILCORP. See Note 18 – Subsequent Event for further information.

In early 2003, Ameren issued, pursuant to the shelf registration statement, 6.325 million shares at $40.50 per share. We received net proceeds of $248 million after fees which were used to fund the remaining cash portion of the purchase price for our acquisition of CILCORP (see Note 18 – Subsequent Event for further information) and for general corporate purposes.

We may sell all, or a portion of, the remaining registered securities under the shelf registration statement if warranted by market conditions and our capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder. In 2002 and in early 2003, $594 million was issued under the shelf registration statement. At February 13, 2003, the amount remaining on the shelf registration statement was approximately $879 million.

In September 2001, we began issuing new shares of common stock under our dividend reinvestment and stock purchase plan (DRPlus) and in December 2001, we began issuing new shares of common stock in connection with our 401(k) plans. Previously, these requirements were met by purchasing outstanding shares. Under these plans, we issued 2.3 million shares of common stock in 2002 and 0.8 million shares in 2001 that were valued at $92 million and $33 million, respectively.

In December 2001, Ameren Corporation issued Floating Rate Notes (FRNs) totaling $150 million. Interest accrues on the FRNs at the three month LIBOR (reset quarterly) plus 0.95% and is payable quarterly commencing in March 2002. The FRNs are due in December 2003. The proceeds were used to reduce short-term borrowings.

Ameren expects to fund maturities of long-term debt and contractual obligations through a combination of cash flow from operations and external financing.

At December 31, 2002, neither Ameren Corporation, nor any of its subsidiaries, had any off-balance sheet financing arrangements, other than operating leases entered into the ordinary course of business. We do not expect to engage in any significant off-balance sheet financing arrangements in the near future.

Amortization of debt issuance costs and any premium or discounts for the years ended December 31, 2002 of $8 million (2001 - $5 million; 2000 - $6 million) were included in interest expense in the income statement.

AmerenUE

In August 2002, a shelf registration statement filed by AmerenUE with the SEC on Form S-3 was declared effective. This statement authorized the offering from time to time of up to $750 million of various forms of long-term debt and trust preferred securities to refinance existing debt and preferred stock, and for general corporate purposes, including the repayment of short-term debt incurred to finance construction expenditures and other working capital needs.

In August 2002, AmerenUE issued, pursuant to the shelf registration statement, $173 million of 5.25% Senior Secured Notes due September 1, 2012. Interest is payable semi-annually on March 1 and September 1 of each year, beginning March 1, 2003. Net proceeds were $172 million, after debt discount and fees. These senior secured notes are secured by a related series of AmerenUE's first mortgage bonds until the release date as described in the senior secured note indenture. Proceeds were used to redeem, in September 2002, AmerenUE's $125 million principal amount 8.75% first mortgage bonds due December 1, 2021 at a 4.38% premium and AmerenUE's $42 million $1.735 series preferred stock at par. We may sell all, or a portion of, the remaining registered securities under the shelf registration statement if warranted by market conditions and our capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder. At December 31, 2002, the amount remaining on the shelf registration statement was $577 million.

In December 2002, upon receipt of all the necessary federal and state regulatory approvals, AmerenUE, pursuant to Missouri economic development statutes, conveyed most of its Peno Creek combustion turbine generating facility to the City of Bowling Green, Missouri in exchange for the issuance by the City of a taxable industrial development revenue bond in the amount of $103.4 million. Concurrently, the City leased back the facility to AmerenUE for a term of 20 years. The lease term is the same as the final maturity of the bond purchased by AmerenUE. While the lease is a capital lease, no capital was raised in the transaction. AmerenUE is responsible for making rental payments under the lease in an amount sufficient to pay the debt service of the bond. The City's ownership of the facility during the term of the bond and the lease is expected to result in property tax savings to AmerenUE. Under the terms of the lease, AmerenUE retains all operation and maintenance responsibilities for the facility and ownership of the facility is returned to AmerenUE at the expiration of the lease.

Generating Company

In June 2002, Generating Company issued $275 million of 7.95% Senior Notes, Series E, due 2032 (Series E Notes) in a private placement to qualified investors under Rule 144A. Interest is payable semi-annually on June 1 and December 1 of each year, beginning December 1, 2002. Generating Company received net proceeds of $271 million, after debt discount and fees, that were used to reduce short-term borrowings incurred to finance previous generating capacity additions and for general corporate purposes. In January 2003, all note holders completed an exchange of the privately placed notes for new Series F Notes, which are identical in all material respects to the Series E Notes, except that the new series of notes were registered with the SEC and do not contain transfer restrictions.

Generating Company's senior note indenture includes provisions that require it to maintain a senior debt service coverage ratio of at least 1.75 to 1 (for both the prior four fiscal quarters and for the next succeeding four, six-month periods) in order to pay dividends to Ameren or to make payments of principal or interest under certain subordinate indebtedness excluding amounts payable under an intercompany note payable with AmerenCIPS. For the four quarters ending December 31, 2002, this ratio was 4.10 to 1. In addition, the indenture also restricts Generating Company from incurring any additional indebtedness, with the exception of certain permitted indebtedness as defined in the indenture, unless its senior debt service coverage ratio equals at least 2.5 to 1 for the most recently ended four fiscal quarters and its senior debt to total capital ratio would not exceed 60%, both after giving effect to the additional indebtedness on a pro-forma basis. This debt incurrence requirement is disregarded in the event certain rating agencies reaffirm the ratings of Generating Company after considering the additional indebtedness. As of December 31, 2002, Generating Company's senior debt to total capital was 55%.

In November 2000, Generating Company issued $225 million of 7.75% Senior Notes, Series A due 2005 and $200 million principal amount 8.35% Senior Notes, Series B due 2010 in a private placement to qualified investors under Rule 144A. In 2001, all holders completed an exchange of the privately placed Series A or B Notes for respective new Series C and D Notes, which are identical in all material respects, except that the new series of notes do not contain transfer restrictions. Proceeds were used to reduce short-term borrowings incurred in conjunction with the construction of combustion turbine generating facilities, for the construction of subsequent combustion turbine facilities, and for funding working capital and other capital expenditure needs.

AmerenCIPS

In May 2001, a shelf registration statement filed by AmerenCIPS with the SEC on Form S-3 was declared effective. This registration statement enables AmerenCIPS to offer from time to time senior notes in one or more series with an offering price not to exceed $250 million. In June 2001, AmerenCIPS issued $150 million of senior notes due June 2011 with an interest rate of 6.625%. Until the release date as described in the senior secured note indenture, the senior notes will be secured by a related series of AmerenCIPS' first mortgage bonds. The proceeds of these senior notes were used to repay short-term debt and first mortgage bonds maturing in June 2001. At December 31, 2002, the amount remaining on the shelf registration statement was $100 million.

NOTE 9 – VOLUNTARY RETIREMENT AND OTHER RESTRUCTURING CHARGES

Voluntary retirement and other restructuring charges were $92 million in 2002 or $58 million, net of taxes.

In December 2002, approximately 550 employees accepted a voluntary retirement program that was offered to approximately 1,000 of our 7,400 employees. Eligible employees had to be age 50 or over, regular, full-time employees and have at least 10 years of service with Ameren. While we expect to realize significant long-term savings as a result of this program, we incurred a pretax charge of $75 million ($47 million, net of taxes) in December 2002 related to the voluntary retirement program. These costs consisted primarily of special termination benefits associated with our pension and post-retirement benefit plans.

In December 2002, we also retired 343 megawatts of rate-regulated capacity at AmerenUE's Venice, Illinois plant and announced that we were temporarily suspending operation of two coal-fired generating units at Generating Company's Meredosia, Illinois plant, representing 126 megawatts of non rate-regulated power generation capacity. The capacity reductions and related severance charges resulted in a charge of $17 million ($11 million, net of taxes) in December 2002.

NOTE 10 – MISCELLANEOUS, NET

Miscellaneous, net for the years ended December 31, 2002, 2001, and 2000 consisted of the following:

	2002	2001	2000
Miscellaneous income:			
Interest and dividend income	$ 8	$ 4	$ 8
Gain on disposition of property	3	5	2
Contribution in aid of construction	–	7	–
Other	4	6	4
Total miscellaneous income	$ 15	$ 22	$ 14
Miscellaneous expense:			
Minority interest in EEI	$(14)	$ (4)	$ (4)
Loss on disposition of property	–	(2)	(1)
Donations, including 2002 rate settlement	(26)	(1)	(6)
Other	(10)	(9)	(10)
Total miscellaneous expense	$(50)	$(16)	$(21)

NOTE 11 – INCOME TAXES

Total income tax expense for 2002 resulted in an effective tax rate of 38% on earnings before income taxes (39% in 2001 and 2000).

The principal reasons such rates differ from the statutory federal rate for the years ended December 31, 2002, 2001, and 2000 were as follows:

	2002	2001	2000
Statutory federal income tax rate:	35%	35%	35%
Increases (decreases) from:			
Depreciation differences	2	2	2
State tax	3	3	3
Other	(2)	(1)	(1)
Effective income tax rate	38%	39%	39%

Components of income tax expense for the years ended December 31, 2002, 2001, and 2000 were as follows:

	2002	2001	2000
Taxes currently payable (principally federal):			
Included in operating expenses	$185	$280	$307
Included in other income	(13)	5	(3)
	172	285	304
Deferred taxes (principally federal):			
Included in operating expenses:			
Depreciation differences	83	9	(5)
Other	(9)	19	7
Included in other income	–	–	–
	74	28	2
Deferred investment tax credits, amortization:			
Included in operating expenses	(9)	(8)	(8)
Total income tax expense	$237	$305	$298

In accordance with SFAS 109, "Accounting for Income Taxes," a regulatory asset, representing the probable recovery from customers of future income taxes, which is expected to occur when temporary differences reverse, was recorded along with a corresponding deferred tax liability. Also, a regulatory liability, recognizing the lower expected revenue resulting from reduced income taxes associated with amortizing accumulated deferred investment tax credits was recorded. Investment tax credits have been deferred and will continue to be credited to income over the lives of the related property.

We adjust our deferred tax liabilities for changes enacted in tax laws or rates. Recognizing that regulators will probably reduce future revenues for deferred tax liabilities initially recorded at rates in excess of the current statutory rate, reductions in the deferred tax liability were credited to the regulatory liability.

Temporary differences gave rise to the following deferred tax assets and deferred tax liabilities at December 31, 2002, 2001, and 2000:

	2002	2001
Accumulated deferred income taxes:		
Depreciation	$1,161	$1,040
Regulatory assets, net	405	434
Capitalized taxes and expenses	237	184
Deferred benefit costs	(79)	(68)
Other	(12)	31
Total net accumulated deferred income tax liabilities	$1,712	$1,621

NOTE 12 – RETIREMENT BENEFITS

We have defined benefit and post-retirement benefit plans covering substantially all employees of AmerenUE, AmerenCIPS and Ameren Services Company and certain employees of Resources Company and its subsidiaries.

Pension

Pension benefits are based on the employees' years of service and compensation. Our plans are funded in compliance with income tax regulations and federal funding requirements. We made cash contributions totaling $31 million to our defined benefit retirement plan during 2002. At December 31, 2002, we recorded a minimum pension liability of $102 million after taxes, which resulted in a charge to OCI and a reduction in stockholders' equity. Based on the performance of plan assets through December 31, 2002, we expect to be required under the Employee Retirement Income Security Act of 1974 to fund $150 million to $175 million annually in 2005, 2006 and 2007 in order to maintain minimum funding levels. These amounts are estimates and may change based on actual stock market performance, changes in interest rates, and any changes in government regulations.

As mentioned in Note 9 – Voluntary Retirement and Other Restructuring Charges, approximately 550 employees accepted a voluntary retirement program in December 2002. Special termination benefits for 2002 included in the table below represent the enhanced improvement in benefits provided to the employees who voluntarily retired in December 2002.

The funded status of Ameren's pension plan for the years ended December 31, 2002 and 2001 were as follows:

	2002	2001
Change in benefit obligation:		
Net benefit obligation		
at beginning of year	$1,418	$1,362
Service cost	33	32
Interest cost	103	100
Actuarial loss	64	14
Special termination benefits	65	–
Benefits paid	(96)	(90)
Net benefit obligation at end of year	$1,587	$1,418
Change in plan assets: (a)		
Fair value of plan assets		
at beginning of year	$1,225	$1,359
Actual return on plan assets	(101)	(45)
Employer contributions	31	1
Benefits paid	(96)	(90)
Fair value of plan assets at end of year	$1,059	$1,225
Funded status – deficiency	$ 528	$193
Unrecognized net actuarial loss	(324)	(33)
Unrecognized prior service cost	(68)	(77)
Unrecognized net transition asset	3	5
Accrued pension cost at December 31	$ 139	$ 88

(a) Plan assets consist principally of common stocks (60%) and fixed income securities (40%).

Amounts recognized in the consolidated balance sheet consist of:		
Accrued pension liability	$ 377	$ 88
Intangible asset	(74)	–
Accumulated other		
comprehensive income	(164)	–
Accrued pension cost at December 31	$ 139	$ 88

Components of Ameren's net periodic pension benefit cost during 2002, 2001 and 2000 were as follows:

	2002	2001	2000
Service cost	$ 33	$ 32	$ 30
Interest cost	103	100	98
Expected return on plan assets	(114)	(115)	(110)
Amortization of:			
Transition asset	(1)	(1)	(1)
Prior service cost	9	9	7
Actuarial gain	(12)	(21)	(21)
Net periodic benefit cost	$ 18	$ 4	$ 3
Net periodic benefit cost, including special termination benefits	$ 83	$ 4	$ 3

Pension costs were $18 million for 2002, $4 million for 2001, and $3 million for 2000 of which 16%, 16% and 21%, were charged to construction accounts, respectively.

Assumptions for actuarial present value of projected benefit obligations during 2002, 2001, and 2000 were as follows:

	2002	2001	2000
Discount rate at measurement date	6.75%	7.25%	7.50%
Expected return on plan assets	8.50%	8.50%	8.50%
Increase in future compensation	3.75%	4.25%	4.50%

Post-Retirement

Our funding policy for post-retirement benefits is to annually fund the Voluntary Employee Beneficiary Association trusts (VEBA) with the lesser of the net periodic cost or the amount deductible for federal income tax purposes. Post-retirement benefit costs were $74 million for 2002, $63 million for 2001 and $58 million for 2000 of which approximately 18%, 18%, and 17% were charged to construction accounts, respectively. Ameren's transition obligation at December 31, 2002 is being amortized over the next 12 years. The MoPSC and the ICC allow the recovery of post-retirement benefit costs in rates to the extent that such costs are funded.

Plan amendments included in the table below represent a favorable change to our net benefit obligation and relate to increasing retiree premiums and placing limits on healthcare benefits.

The funded status of Ameren's post-retirement benefit plans at December 31, 2002 and 2001 were as follows:

	2002	2001
Change in benefit obligation:		
Net benefit obligation		
at beginning of year	$701	$589
Service cost	26	23
Interest cost	51	47
Employee contributions	2	1
Plan amendments	(186)	–
Actuarial loss	211	80
Special termination benefits	8	–
Benefits paid	(42)	(39)
Net benefit obligation at end of year	$771	$701
Change in plan assets: (a)		
Fair value of plan assets		
at beginning of year	$300	$290
Actual return on plan assets	(26)	(17)
Employer contributions	74	65
Employee contributions	2	1
Benefits paid	(41)	(39)
Fair value of plan assets at end of year	309	300
Funded status – deficiency	462	401
Unrecognized net actuarial loss	(389)	(134)
Unrecognized prior service cost	47	2
Unrecognized net transition obligation	(21)	(180)
Post-retirement benefit liability		
at December 31	$ 99	$ 89

(a) Plan assets consisted principally of common stocks (49%), bonds (38%) and money market instruments (13%).

Components of Ameren's net periodic post-retirement benefit cost as of December 31, 2002, 2001, and 2000 were as follows:

	2002	2001	2000
Service cost	$26	$23	$19
Interest cost	51	47	43
Expected return on plan assets	(27)	(25)	(18)
Amortization of:			
Transition obligation	16	16	16
Actuarial (gain)/loss	8	2	(2)
Net periodic benefit cost	$74	$63	$58
Net periodic benefit cost, including special termination benefits	$82	$63	$58

Assumptions for the post-retirement benefit plan obligation measurements for the years ended December 31, 2002, 2001, and 2000 were as follows:

	2002	2001	2000
Discount rate at measurement date	6.75%	7.25%	7.50%
Expected return on plan assets	8.50%	8.50%	8.50%
Medical cost trend rate (initial)	10.00%	5.25%	5.00%
Medical cost trend rate (ultimate)	5.25%	5.25%	5.00%

A 1% increase in the medical cost trend rate is estimated to increase the net periodic cost and the accumulated post-retirement benefit obligation approximately $7 million and $53 million, respectively. A 1% decrease in the medical cost trend rate is estimated to decrease the net periodic cost and the accumulated post-retirement benefit obligation approximately $6 million and $49 million, respectively.

NOTE 13 – STOCK-BASED COMPENSATION

We have a long-term incentive plan for eligible employees, which provides for the grant of options, performance awards, restricted stock, dividend equivalents and stock appreciation rights. We have not granted any stock options since December 31, 2000, but did grant restricted stock awards in 2002 and 2001 as a component of our compensation programs. We applied APB 25 in accounting for our stock-based compensation for the years ended December 31, 2002, 2001 and 2000. Effective January 1, 2003, we adopted SFAS 123. See Note 1 – Summary of Significant Accounting Policies for further information.

Restricted Stock

Restricted stock awards may be granted under our long-term incentive plan. Upon the achievement of certain performance levels, the restricted stock award vests over a period of seven years, beginning at the date of grant, and includes provisions requiring certain stock ownership levels based on position and salary. An accelerated vesting provision is also included in this plan which reduces the vesting period from seven years to three years. During 2002 and 2001, respectively, 154,678 and 141,788 restricted stock awards were granted. The weighted-average fair value for restricted stock awards granted in 2002 and 2001 was $42.50 and $39.60 per share, respectively. We record unearned compensation (as a component of stockholders' equity) equal to the market value of the restricted stock on the date of grant and charge the unearned compensation to expense over the vesting period. In accordance with SFAS 123, we recorded compensation expense relating to restricted stock awards of approximately $2 million in 2002 (which includes accelerated expense of approximately $1 million related to our voluntary retirement program offered in 2002) and approximately $1 million in 2001.

Stock Options

Options may be granted at a price not less than the fair market value of the common shares at the date of grant. Granted options vest over a period of five years, beginning at the date of grant, and provide for accelerated exercising upon the occurrence of certain events, including retirement. Outstanding options expire on various dates through 2010. Subject to adjustment, four million shares have been authorized to be issued or delivered under our long-term incentive plan. In accordance with APB 25, no compensation expense was recognized related to our stock options for 2002, 2001 or 2000. The pretax effect of weighted-average grant-date fair value of options granted would have been approximately $2 million in each of the years ended 2002, 2001 and 2000 had the fair value method under SFAS 123 been used for options. The fair value method will be used prospectively beginning January 1, 2003. See Note 1 – Summary of Significant Accounting Policies for further information.

The following table summarizes stock option activity during 2002, 2001 and 2000:

	2002	
	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	2,241,107	$35.23
Granted	–	–
Exercised	260,324	36.11
Cancelled or expired	3,330	43.00
Outstanding at end of year	1,977,453	$35.10
Exercisable at end of year	901,187	$36.97

	2001		2000	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	2,430,532	$35.38	1,834,108	$38.22
Granted	–	–	957,100	31.00
Exercised	106,416	38.31	295,693	38.41
Cancelled or expired	83,009	35.77	64,983	37.38
Outstanding at end of year	2,241,107	$35.23	2,430,532	$35.38
Exercisable at end of year	572,092	$38.74	312,736	$39.58

The following table summarizes additional information about stock options outstanding at December 31, 2002:

Exercise Price	Outstanding Shares	Weighted Average Life (Years)	Exercisable Shares
$31.00	837,400	7.0	189,175
35.50	800	2.6	800
35.875	30,630	2.3	30,630
36.625	547,825	6.0	239,325
38.50	80,233	4.1	80,233
39.25	396,099	5.2	277,883
39.8125	5,300	5.5	3,975
43.00	79,166	3.0	79,166

The fair values of stock options were estimated using a binomial option-pricing model with the following assumptions:

Grant Date	Risk-free Interest Rate	Option Term	Expected Volatility	Expected Dividend Yield
2/11/00	6.81%	10 years	17.39%	6.61%
2/12/99	5.44%	10 years	18.80%	6.51%
6/16/98	5.63%	10 years	17.68%	6.55%
4/28/98	6.01%	10 years	17.63%	6.55%
2/10/97	5.70%	10 years	13.17%	6.53%
2/7/96	5.87%	10 years	13.67%	6.32%

NOTE 14 – COMMITMENTS AND CONTINGENCIES

As a result of issues generated in the course of daily business, we are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings, except as otherwise noted in the Notes to our Consolidated Financial Statements, will not have an adverse material effect on our financial position, results of operations or liquidity.

Capital Expenditures

We estimate our capital expenditures over the next five years will be approximately $3 billion - $3.3 billion, including allowance for funds used during construction and capitalized interest, as well as AmerenCILCO. This estimate includes capital expenditures for the construction of new combustion turbine generating facilities and for the replacement of steam generators at our Callaway nuclear plant. In addition, this estimate includes capital expenditures for transmission, distribution and other generation related activities, as well as for compliance with new NO_x (nitrogen oxide) control regulations, as discussed later in this Note. Commitments of $2.25 billion to $2.75 billion were agreed upon in relation to AmerenUE's recent Missouri electric rate case settlement and to meet future rate-regulated generating capacity needs from January 1, 2002 through June 30, 2006.

Our capital program is subject to periodic review and revision, and actual capital costs may vary from the above estimate because of numerous factors. These factors include changes in business conditions, acquisition of additional generating assets, revised load growth estimates, changes in environmental regulations, changes in our existing nuclear plant to meet new regulatory requirements, increasing costs of labor, equipment and materials, and cost of capital.

We intend to transfer at net book value approximately 550 megawatts (approximately $260 million) of generating capacity from our non rate-regulated subsidiary, Generating Company, to our rate-regulated subsidiary, AmerenUE, to comply with AmerenUE's recent Missouri electric rate case settlement and to meet future rate-regulated generating capacity needs. In addition, we intend to replace our retired 343 megawatts of rate-regulated capacity at AmerenUE's Venice, Illinois plant (see Note 9 – Voluntary Retirement and Other Restructuring Charges for further information) with the addition of 117 megawatts of capacity by 2005 and at least 330 megawatts of capacity by 2006 at Venice. Total costs expected to be incurred for these units approximate $175 million of which approximately $100 million was committed as of December 31, 2002.

Fuel Purchase Commitments

To supply a portion of the fuel requirements of our generating plants, we have entered into various long-term commitments for the procurement of fossil and nuclear fuel. In addition, we have entered into various long-term commitments for the purchase of electricity. Total estimated fuel purchase commitments at December 31, 2002 were as follows:

	Coal	Gas	Nuclear	Electric Capacity
2003	$ 590	$ 81	$ 9	$ 35
2004	515	47	1	35
2005	307	44	9	33
2006	178	16	9	33
2007	107	2	1	33
Thereafter	253	4	20	107
Total	$1,950	$194	$49	$276

Nuclear Plant Insurance Coverage

Our insurance coverage at AmerenUE's Callaway nuclear plant at December 31, 2002, was as follows:

	Maximum Coverages	Maximum Assessments for Single Incidents
Type and source of coverage –		
Public Liability:		
American Nuclear Insurers	$ 200	$ –
Pool Participation	9,250	88 (a)
	$9,450 (b)	$88
Nuclear Worker Liability:		
American Nuclear Insurers	$ 300 (c)	$ 4
Property Damage:		
Nuclear Electric Insurance Ltd.	$2,750 (d)	$21
Replacement Power:		
Nuclear Electric Insurance Ltd.	$ 490 (e)	$ 7

(a) *Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended (Price-Anderson). This is subject to retrospective assessment with respect to loss from an incident at any U.S. reactor, payable at $10 million per year. Price-Anderson expired in August 2002 and renewal legislation is pending before Congress. Until Price-Anderson is extended, its provisions continue to apply to existing nuclear plants.*

(b) *Limit of liability for each incident under Price-Anderson.*

(c) *Industry limit for potential liability from workers claiming exposure to the hazard of nuclear radiation.*

(d) *Includes premature decommissioning costs.*

(e) *Weekly indemnity of $3.5 million for 52 weeks, which commences after the first 8 weeks of an outage, plus $2.8 million per week for 110 weeks thereafter.*

Price-Anderson limits the liability for claims from an incident involving any licensed U.S. nuclear facility. The limit is based on the number of licensed reactors and is adjusted at least every five years based on the Consumer Price Index. Utilities owning a nuclear reactor cover this exposure through a combination of private insurance and mandatory participation in a financial protection pool, as established by Price-Anderson.

If losses from a nuclear incident at Callaway exceed the limits of, or are not subject to, insurance, or if coverage is not available, we self-insure the risk. Although we have no reason to anticipate a serious nuclear incident, if one did occur, it could have a material, but indeterminable, adverse effect on our financial position, results of operations or liquidity.

Leases

The following table summarizes our lease obligations at December 31, 2002:

	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Capital leases (a)	$216	$31	$ 70	$30	$ 85
Operating leases (b)	171	22	35	26	88
Total lease obligations	$387	$53	$105	$56	$173

(a) See Note 5 – Nuclear Fuel Lease and Note 8 – Long-Term Debt and Capitalization for further discussion.

(b) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The amounts for these items are included in the less than 1 year, 1-3 years and 4-5 years. Amounts for after 5 years are not included in the total amount due to the indefinite periods. The estimated obligation for after 5 years is $1 million annually for both the real estate leases and the railroad licenses.

Ameren leases various facilities, office equipment, plant equipment and railcars under operating leases. We also have capital leases relating to nuclear fuel and combustion turbine generators. As of December 31, 2002, rental expense, included in Other Operations and Maintenance expenses, totaled approximately $21 million (2001 - $22 million; 2000 - $34 million). See Note 5 – Nuclear Fuel Lease and Note 8 – Long-Term Debt and Capitalization for further information.

Environmental Matters

We are subject to various environmental regulations by federal, state, and local authorities. From the beginning phases of siting and development, to the ongoing operation of existing or new electric generating, transmission, and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, special, protected, and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical and waste handling, and noise impacts. Our activities require complex and often lengthy processes to obtain approvals, permits, or licenses for new, existing, or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires preparation of release prevention plans and emergency response procedures. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operations, as required. The more significant matters are discussed below.

Clean Air Act

The Clean Air Act affects both existing generating facilities and new projects. The Clean Air Act and many state laws require significant reductions in SO_2 (sulfur dioxide) and NO_x emissions that result from burning fossil fuels. The Clean Air Act also contains other provisions that could materially affect some of our projects. Various provisions require permits, inspections, or installation of additional pollution control technology or may require the purchase of emission allowances. Certain of these provisions are described in more detail below.

The Clean Air Act creates a marketable commodity called an SO_2 "allowance." All generating facilities over 25 megawatts that emit SO_2 must obtain allowances in order to operate after 1999. Each allowance gives the owner the right to emit one ton of SO_2. All existing generating facilities have been allocated allowances based on a facility's past production and the statutory emission reduction goals. If additional allowances are needed for new generating facilities, they can be purchased from facilities having excess allowances or from SO_2 allowance banks. Our generating facilities comply with the SO_2 allowance caps through the purchase of allowances or use of low sulfur fuels. The additional costs of obtaining allowances needed for future generation projects should not materially affect our ability to build, acquire, and operate them.

The U.S. Environmental Protection Agency (EPA) issued a rule in October 1998 requiring 22 Eastern states and the District of Columbia to reduce emissions of NO_x in order to reduce ozone in the Eastern United States. Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_x emission budget for each state, including Illinois. The EPA rule requires states to implement controls sufficient to meet their NO_x budget by May 31, 2004.

As a result of these state requirements, Generating Company estimates spending an additional $40 million for pollution control capital expenditures and NO_x credits by 2006. In February 2002, the EPA proposed similar rules for Missouri where the majority of AmerenUE's facilities are located. Assuming the Missouri rules are ultimately finalized, AmerenUE estimates spending approximately $170 million to comply with these rules for NO_x control on the AmerenUE generating system by 2006. In summary, we currently estimate our future capital expenditures to comply with the final NO_x regulations could range from $200 million to $250 million. This estimate includes the assumption that the regulations will require the installation of Selective Catalytic Reduction technology on some of our units, as well as additional controls.

Under both Illinois and Missouri regulatory programs, Generating Company and AmerenUE have applied for Early Reduction NO_x credits which would allow them to manage compliance strategies by either purchasing

NO_x control equipment or utilizing credits. Generating Company and AmerenUE are eligible for such credits due to the current low NO_x emission rates achieved on some of their boilers due to past NO_x control efforts.

On December 31, 2002, the EPA published in the Federal Register revisions to the New Source Review (NSR) programs under the Clean Air Act, including changes to the routine maintenance, repair and replacement exclusions. Various Northeastern states have filed a petition with the United States District Court for the District of Columbia challenging the legality of the revisions to the NSR programs. It is likely that various industries and environmental groups will seek to intervene in that challenge. At this time, we are unable to predict the impact of this challenge on our future financial position, results of operations, or liquidity.

National Ambient Air Quality Standards

In July 1997, the EPA issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. The standards were challenged by industry and some states, and arguments were eventually heard by the U.S. Supreme Court. In February 2001, the Supreme Court upheld the standards in large part, but remanded a number of significant implementation issues back to the EPA for resolution. The EPA is currently working on a new rulemaking to address the issues raised by the Supreme Court. New ambient standards may require significant additional reductions in SO_2 and NO_x emissions from our power plants by 2008. At this time, we are unable to predict the ultimate impact of these revised air quality standards on our future financial position, results of operations or liquidity.

Mercury and Regional Haze Regulations

In December 1999, the EPA issued a decision to regulate mercury emissions from coal-fired power plants by 2008. The EPA is scheduled to propose regulations by 2004. These regulations have the potential to add significant capital and/or operating costs to the Ameren generating systems after 2005. The EPA is scheduled to issue Best Available Retrofit Technology (BART) guidelines to address visibility impairment (so called "Regional Haze") across the United States from sources of air pollution, including coal-fired power plants. The guidelines are to be used by states to mandate pollution control measures for SO_2 and NO_x emissions. These rules could also add significant pollution control costs to the Ameren generating systems between 2008 and 2012.

Multi-Pollutant Legislation

The United States Congress has been working on legislation to consolidate the numerous air pollution regulations facing the utility industry. This "multi-pollutant" legislation is expected to be deliberated in Congress in 2003. While the cost to comply with such legislation, if enacted, could be significant, it is anticipated that the costs would be less than the combined impact of the new National Ambient Air Quality Standards, mercury and Regional Haze regulations, discussed above. Pollution control costs under such legislation are expected to be incurred in phases from 2007 through 2015. At this time, we are unable to predict the ultimate impact of the above expected regulations and this legislation on our future financial position, results of operations, or liquidity; however, the impact could be material.

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. The related Kyoto Protocol was signed by the United States but has since been rejected by the President, who instead has asked for an 18% decrease in carbon intensity on a voluntary basis. Future initiatives on this issue and the ultimate effects of the Kyoto Protocol and the President's initiatives on us are unknown. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies. Coal-fired power plants, however, are significant sources of carbon dioxide emissions, a principal greenhouse gas. Therefore, our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Clean Water Act

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. These rules pertain to existing generating facilities that currently employ a cooling water intake structure whose flow exceeds 50 million gallons per day. A final action on the proposed rules is expected by August 2003. The proposed rule may require us to install additional intake screens or other protective measures, as well as extensive site specific study and monitoring requirements. There is also the possibility that the proposed rules may lead to the installation of cooling towers on some of our facilities. Our compliance costs associated with the final rules are unknown, but could be material.

Remediation

We are involved in a number of remediation actions to clean up hazardous waste sites as required by federal and state law. Such statutes require that responsible parties fund remediation actions regardless of fault, legality of original disposal, or ownership of a disposal site. AmerenUE and AmerenCIPS have been identified by the federal or state governments as a potentially responsible party (PRP) at several contaminated sites.

We own or are otherwise responsible for 14 former manufactured gas plant (MGP) sites in Illinois. The ICC permits the recovery of remediation and litigation costs associated with certain former MGP sites located in Illinois from our Illinois electric and natural gas utility customers through environmental adjustment rate riders. To be recoverable, such costs must be prudently and properly incurred and are subject to annual reconciliation review by the ICC. Through December 31, 2002, the total costs deferred, net of recoveries from insurers and through environmental adjustment rate riders, were $26 million.

In addition, we own or are otherwise responsible for 10 MGP sites in Missouri and one in Iowa. Unlike Illinois, we do not have in effect in Missouri a rate rider mechanism which permits remediation costs associated with MGP sites to be recovered from utility customers, and we do not have any retail utility operations in Iowa.

In June 2000, the EPA notified AmerenUE and numerous other companies that former landfills and lagoons in Sauget, Illinois, may contain soil and groundwater contamination. These sites are known as Sauget Area 1 and Sauget Area 2. From approximately 1926 until 1976, AmerenUE operated a power generating facility adjacent to Sauget Area 2 and currently owns and operates electric transmission and distribution facilities in or near Sauget Areas 1 and 2.

In September 2000, the United States Department of Justice was granted leave by the United States District Court - Southern District of Illinois to add numerous additional parties, including AmerenUE, to a preexisting lawsuit between the government and others. The government seeks recovery of response costs under the Comprehensive Environmental Response Compensation Liability Act of 1980 (CERCLA or Superfund), incurred in connection with the remediation of Sauget Area 1. We believe the final resolution of this lawsuit and the remediation of Sauget Area 1 will not have a material adverse effect on our financial position, results of operations or liquidity.

In September 2001, the EPA proposed in the Federal Register that Sauget Area 1 and Sauget Area 2 be listed on the National Priorities List (NPL). The inclusion of a site on the NPL allows the EPA to access Superfund trust monies to fund site remediations. With respect to Sauget Area 2, AmerenUE has joined with other PRPs to evaluate the extent of potential contamination. We are unable to predict the ultimate impact of the Sauget Area 2 site on our financial position, results of operations or liquidity.

In October 2002, AmerenUE was included in a Unilateral Administrative Order (UAO) list of potentially liable parties for groundwater contamination for a portion of the Sauget Area 2 site. The UAO encompasses the groundwater contamination releasing to the Mississippi River adjacent to a chemical company's former chemical waste landfill and the resulting impact area in the Mississippi River. AmerenUE is being asked to participate in response activities that involve the installation of a barrier wall with three recovery wells. The projected cost for this remedy method is $26 million. In November 2002, AmerenUE sent a letter to the EPA asserting its defenses to the UAO and requested its removal from the list of potentially responsible parties under the UAO.

In addition, our operations, or that of our predecessor companies, involve the use, disposal and, in appropriate circumstances, the cleanup of substances regulated under environmental protection laws. We are unable to determine the impact these actions may have on our financial position, results of operations or liquidity.

Labor Agreements

Certain employees of Ameren are represented by the International Brotherhood of Electrical Workers (IBEW) and the International Union of Operating Engineers (IUOE). These employees comprise approximately 63% of our workforce. Labor agreements covering 7% of the employees extend through 2006. Labor agreements covering most of the remaining employees represented by IBEW and IUOE expire by June 2003. We cannot predict what issues may be raised by the collective bargaining units and, if raised, whether negotiations concerning such issues will be successfully concluded.

Asbestos-Related Litigation

Ameren, AmerenCIPS and AmerenUE have been named, along with numerous other parties, in a number of lawsuits which have been filed by certain plaintiffs claiming varying degrees of injury from asbestos exposure. Most have been filed in the Circuit Court of Madison County, Illinois. The number of total defendants named in each case is significant with as many as 110 parties named in a case to as few as six. However, the average number of parties is 54 in the cases that are currently pending.

The claims filed against Ameren, AmerenCIPS and AmerenUE allege injury from asbestos exposure during the plaintiffs' activities at our electric generating plants (in the case of AmerenCIPS, its former plants are now owned by Generating Company). In each lawsuit, the plaintiff seeks unspecified damages in excess of

$50,000, which typically would be shared among the named defendants. A total of 121 such lawsuits have been filed against Ameren, AmerenCIPS and AmerenUE of which 45 are pending, 14 have been settled and 62 have been dismissed.

Regulation

Regulatory changes enacted and being considered at the federal and state levels continue to change the structure of the utility industry and utility regulation, as well as encourage increased competition. At this time, we are unable to predict the impact of these changes on our future financial position, results of operations or liquidity. See Note 2 – Rate and Regulatory Matters for further information.

NOTE 15 – CALLAWAY NUCLEAR PLANT

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or 1/10 of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel. Pursuant to this Act, AmerenUE collects one mill from its customers for each kilowatthour of electricity that it generates from Callaway. Electric utility rates charged to customers provide for recovery of such costs. The DOE is not expected to have its permanent storage facility for spent fuel available until at least 2015. We have sufficient storage capacity at Callaway until 2020 and have the capability for additional storage capacity through the licensed life of the plant. The delayed availability of the DOE's disposal facility is not expected to adversely affect the continued operation of Callaway through its currently licensed life.

Electric utility rates charged to customers provide for recovery of Callaway decommissioning costs over the life of the plant, based on an assumed 40-year life, ending with expiration of the plant's operating license in 2024. The Callaway site is assumed to be decommissioned based on immediate dismantlement method and removal from service. Decommissioning costs, including decontamination, dismantling and site restoration, are estimated to be $515 million in current year dollars and are expected to escalate approximately 4% per year through the end of decommissioning activity in 2033. Decommissioning costs are charged to depreciation expense over Callaway's service life and amounted to approximately $7 million in each of the years 2002, 2001 and 2000. Every three years, the MoPSC and ICC require AmerenUE to file updated cost studies for decommissioning Callaway, and electric rates may be adjusted at such times to reflect changed estimates. The latest studies were filed in 2002. Costs collected from customers are deposited in an external trust fund to provide for Callaway's decommissioning. Fund earnings are expected to average approximately 9.5% annually through the date of decommissioning. If the assumed return on trust assets is not earned, we believe it is probable that any such earnings deficiency will be recovered in rates. Trust fund earnings, net of expenses, appear on the consolidated balance sheet as increases in the nuclear decommissioning trust fund and in the accumulated provision for nuclear decommissioning.

The FASB issued SFAS 143 (see Note 1 – Summary of Significant Accounting Policies for further information), which will result in a change to Ameren's recognition, measurement, and classification of nuclear decommissioning costs.

NOTE 16 – FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Temporary Investments/ Short-Term Borrowings

The carrying amounts approximate fair value because of the short-term maturity of these instruments.

Marketable Securities

The fair value is based on quoted market prices obtained from dealers or investment managers.

Nuclear Decommissioning Trust Fund

The fair value is estimated based on quoted market prices for securities.

Preferred Stock of Subsidiaries

The fair value is estimated based on the quoted market prices for the same or similar issues.

Long-Term Debt

The fair value is estimated based on the quoted market prices for same or similar issues or on the current rates offered to Ameren for debt of comparable maturities.

Derivative Financial Instruments

Market prices used to determine fair value are based on management's estimates, which take into consideration factors like closing exchange prices, over-the-counter prices, and time value of money and volatility factors. All derivative financial instruments are carried at fair value on the consolidated balance sheet.

Carrying amounts and estimated fair values of our financial instruments at December 31, 2002 and 2001 were as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including current portion)	$3,772	$4,014	$2,974	$3,052
Preferred stock	193	170	235	207

We have investments in debt and equity securities that are held in trust funds for the purpose of funding the nuclear decommissioning of our Callaway site. See Note 15 – Callaway Nuclear Plant for further information. We have classified these investments in debt and equity securities as available for sale and have recorded all such investments at their fair market value at December 31, 2002 and 2001. Investments by the nuclear decommissioning trust funds are allocated 60% to 65% to equity securities with the balance invested in fixed income securities. Fixed income investments are limited to U.S. government or agency securities, municipal bonds or investment-grade corporate securities. The proceeds from the sale of investments were $141 million in 2002 (2001 - $230 million; 2000 - $61 million). Using the specific identification method to determine cost, the gross realized gains on those sales were approximately $35 million for 2002 (2001 - $4 million; 2000 - $1 million). Net realized and unrealized gains and losses are reflected in the accumulated provision for nuclear decommissioning on the consolidated balance sheet, which is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trusts could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in electric rates paid by customers.

Costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund at December 31, 2002 and 2001 were as follows:

2002		Gross Unrealized		
Security Type	Cost	Gain	(Loss)	Fair Value
Debt securities	$ 57	$ 4	$–	$ 61
Equity securities	89	17	–	106
Cash equivalents	5	–	–	5
	$151	$21	$–	$172

2001		Gross Unrealized		
Security Type	Cost	Gain	(Loss)	Fair Value
Debt securities	$ 57	$ 2	$–	$ 59
Equity securities	78	44	–	122
Cash equivalents	6	–	–	6
	$141	$46	$–	$187

The contractual maturities of investments in debt securities at December 31, 2002 were as follows:

	Cost	Fair Value
Less than 5 years	$22	$23
5 years to 10 years	20	21
Due after 10 years	15	17
	$57	$61

NOTE 17 – SEGMENT INFORMATION

Ameren's principal business segment is comprised of the utility operating companies that provide electric and gas service in portions of Missouri and Illinois. The other reportable segment includes the nonutility subsidiaries, as well as our 60% interest in EEI.

The accounting policies of the segments are the same as those described in Note 1 - Summary of Significant Accounting Policies. Segment data includes intersegment revenues, as well as a charge allocating costs of administrative support services to each of the operating companies. These costs are accumulated in a separate subsidiary, Ameren Services Company, which provides a variety of support services to Ameren and its subsidiaries. We evaluate the performance of our segments and allocate resources to them, based on revenues, operating income and net income.

The table below summarizes information about the reported revenues, net income, and total assets of Ameren for the years ended December 31, 2002, 2001 and 2000:

2002	Utility Operations	Other	Reconciling Items	Total
Revenues	$4,279	$320	$(758)(a)	$3,841
Net income	364	18	–	382
Total assets	11,476	224	(201)	11,499
2001				
Revenues	$4,415	$248	$(805)(a)	$3,858
Net income	467	2	–	469
Total assets	11,171	240	(1,010)	10,401
2000				
Revenues	$4,119	$294	$(557)(a)	$3,856
Net income	457	–	–	457
Total assets	10,777	287	(1,350)	9,714

(a) Elimination of intercompany revenues.

Specified items included in segment profit/loss for the years ended December 31, 2002, 2001 and 2000:

2002	Utility Operations	Other	Reconciling Items	Total
Interest expense	$239	$12	$(32)(b)	$219
Depreciation and amortization expense	401	14	16	431
Income tax expense	224	19	(6)	237
2001				
Interest expense	$231	$11	$(43)(b)	$199
Depreciation and amortization expense	382	12	12	406
Income tax expense	299	7	(1)	305
2000				
Interest expense	$205	$12	$(37)(b)	$180
Depreciation and amortization expense	360	13	10	383
Income tax expense	294	4	–	298

(b) Elimination of intercompany interest charges.

Specified item related to segment assets as of December 31, 2002, 2001 and 2000:

2002	Utility Operations	Other	Reconciling Items	Total
Expenditures for additions to long-lived assets	$ 758	$ 3	$ 26	$ 787
2001				
Expenditures for additions to long-lived assets	$1,058	$10	$ 34	$1,102
2000				
Expenditures for additions to long-lived assets	$ 872	$45	$ 12	$ 929

NOTE 18 – SUBSEQUENT EVENT

On January 31, 2003, after receipt of the necessary regulatory agency approvals and clearance from the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act, we completed our acquisition of all of the outstanding common stock of CILCORP Inc. from AES. CILCORP is the parent company of Peoria, Illinois-based Central Illinois Light Company, which operated as CILCO. With the acquisition, CILCO became an Ameren subsidiary, but remains a separate utility company, operating as AmerenCILCO. On February 4, 2003, we also completed our acquisition of AES Medina Valley Cogen (No. 4), LLC (Medina Valley) which indirectly owns a 40 megawatt, gas-fired electric generation plant. With the acquisition, Medina Valley became a wholly-owned subsidiary of Resources Company, which we renamed as AmerenEnergy Medina Valley Cogen (No. 4), LLC. The CILCORP and AmerenEnergy Medina Valley Cogen (No. 4), LLC financial statements will be included in our consolidated financial statements effective with the January and February 2003 acquisition dates.

We acquired CILCORP to complement our existing Illinois gas and electric operations. The purchase includes CILCO's rate-regulated electric and natural gas businesses in Illinois serving approximately 200,000 and 205,000 customers, respectively, of which approximately 150,000 are combination electric and gas customers. CILCO's service territory is contiguous to our service territory. In addition, the purchase includes approximately 1,200 megawatts of largely coal-fired generating capacity, most of which is expected to become non rate-regulated in 2003.

The total purchase price was approximately $1.4 billion and included the assumption of CILCORP and Medina Valley debt and preferred stock at closing of approximately $900 million, with the balance of the purchase price of approximately $500 million paid with cash on hand. The purchase price is subject to certain adjustments for working capital and other changes pending the finalization of CILCORP's closing balance sheet. The cash component of the purchase price came from Ameren's issuances in September 2002 of 8.05 million common shares and in early 2003 of 6.325 million shares of common stock which generated aggregate net proceeds of $575 million.

For the year ended December 31, 2002, CILCORP had revenues of $782 million, operating income of $109 million, and net income from continuing operations of $31 million, and as of December 31, 2002, had total assets of $1.9 billion. For the year ended December 31, 2001, CILCORP had revenues of $815 million, operating income of $126 million, and net income from continuing operations of $28 million, and as of December 31, 2001 had total assets of $1.8 billion. These results may not be the same when consolidated with Ameren.

Millions of Dollars, Except Share and Per Share Amounts and Ratios	2002	2001	2000	1999	1998
Results of operations Year Ended December 31,					
Operating revenues	$3,841	$3,858	$3,856	$3,536	$3,318
Operating expenses	3,218	3,193	3,216	2,973	2,747
Operating income	623	665	640	563	571
Income before extraordinary charge and cumulative effect of change in accounting principle	382	476	457	385	386
Extraordinary charge and cumulative effect of change in accounting principle, net of income taxes	–	7	–	–	–
Net income	$382	$469	$457	$385	$386
Average common shares outstanding	146,138,419	137,320,692	137,215,462	137,215,462	137,215,462
Assets, obligations and equity capital December 31,					
Total assets	$11,499	$10,401	$9,714	$9,178	$8,847
Long-term debt obligations	3,433	2,835	2,745	2,448	2,289
Preferred stock of subsidiaries not subject to mandatory redemption	193	235	235	235	235
Common equity	3,842	3,349	3,197	3,090	3,056
Financial indices Year Ended December 31,					
Earnings per share of common stock (based on average shares outstanding)	$2.61	$3.41	$3.33	$2.81	$2.82
Dividend payout ratio	98% (a)	75%	76%	90%	90%
Return on average common stock equity	10.56%	14.54%	14.60%	12.56%	12.82%
Ratio earnings to fixed charges					
Ameren Corporation	3.51	4.42	4.59	4.20	4.06
AmerenUE	5.82	6.08	5.33	5.64	4.99
AmerenCIPS	2.06	2.87	4.05	2.98	4.13
Generating Company	1.59	2.63	2.99	–	–
Book value per common share	$24.94	$24.26	$23.30	$22.52	$22.27

(a) *Excluding voluntary retirement and other restructuring charges, the dividend payout ratio was 85%.*

Capitalization ratios December 31,	2002	2001	2000	1999	1998
Common equity	51.6%	47.0%	50.8%	53.4%	53.0%
Preferred stock	2.6	3.3	3.7	4.1	4.1
Long-term debt	45.8	49.7	45.5	42.5	42.9
	100.0%	100.0%	100.0%	100.0%	100.0%

ELECTRIC OPERATING STATISTICS

Year Ended December 31,	2002	2001	2000	1999	1998
Electric operating revenues Millions					
Residential	$1,202	$1,133	$1,142	$1,097	$1,125
Commercial	1,024	1,020	997	956	966
Industrial	511	541	505	505	511
Wholesale	291	236	208	108	91
Other	23	23	24	24	23
Native	3,051	2,953	2,876	2,690	2,716
Interchange	200	309	477	399	240
EEI	185	110	164	177	152
Miscellaneous	84	125	75	72	29
Credit to customers	–	10	(65)	(38)	(43)
Total Electric Operating Revenues	$3,520	$3,507	$3,527	$3,300	$3,094
Kilowatthour sales Millions					
Residential	16,704	15,678	15,683	14,863	15,188
Commercial	17,224	16,873	16,644	15,418	15,555
Industrial	12,442	13,175	11,914	11,549	11,582
Wholesale	8,936	6,992	6,244	3,002	2,446
Other	280	284	307	303	303
Native	55,586	53,002	50,792	45,135	45,074
Interchange	8,165	10,130	14,679	12,371	8,075
EEI	6,588	5,824	6,914	9,270	8,296
Total Kilowatthour Sales	70,339	68,956	72,385	66,776	61,445
Electric customers End of Year in Thousands					
Residential	1,319	1,312	1,307	1,298	1,289
Commercial	194	192	191	187	180
Industrial	6	6	6	6	6
Wholesale and other	4	4	4	4	4
Total Electric Customers	1,523	1,514	1,508	1,495	1,479
Residential customer data Average					
Kilowatthours used	11,680	11,956	12,579	11,827	11,986
Annual electric bill	$848.06	$869.25	$895.20	$859.53	$873.28
Revenue per kilowatthour	7.26¢	7.27¢	7.12¢	7.27¢	7.29¢
Capability at time of peak, including net purchases and sales Megawatts					
AmerenUE	9,765	9,747	9,359	9,141	9,027
AmerenEnergy Resources/AmerenCIPS	4,223	3,549	3,560	2,556	2,417
Generating capability at time of peak Megawatts					
AmerenUE	8,647	8,618	8,320	8,352	8,282
AmerenEnergy Resources/AmerenCIPS	4,327	3,945	3,443	3,027	3,040
Coal burned Millions of Tons	27.1	24.5	25.3	23.6	23.0
Price per ton of coal Average	$18.06	$18.88	$18.94	$20.34	$21.29
Source of energy supply					
Fossil	76.7%	72.3%	83.2%	85.4%	83.5%
Nuclear	11.4	11.6	18.8	17.9	17.7
Hydro	1.6	1.4	1.6	3.1	3.8
Purchased and interchanged, net	10.3	14.7	(3.6)	(6.4)	(5.0)
	100.0%	100.0%	100.0%	100.0%	100.0%

GAS OPERATING STATISTICS

Year Ended December 31,	2002	2001	2000	1999	1998
Natural gas operating revenues Millions					
Residential	$192	$187	$204	$146	$135
Commercial	75	83	69	52	50
Industrial	37	40	17	18	19
Off system sales	4	6	18	4	3
Miscellaneous	7	26	16	8	10
Total Natural Gas Operating Revenues	$315	$342	$324	$228	$217
MMBtu sales Millions					
Residential	21	19	25	21	21
Commercial	9	9	9	8	8
Industrial	8	7	3	4	6
Off system sales	1	1	4	1	1
Total MMBtu Sales	39	36	41	34	36
Natural gas customers End of Year in Thousands					
Residential	270	269	270	267	265
Commercial and Industrial	30	30	31	30	31
Total Natural Gas Customers	300	299	301	297	296
Peak day throughput Thousands of MMBtus					
AmerenCIPS	142	188	226	247	229
AmerenUE	118	128	169	184	157
Total Peak Day Throughput	260	316	395	431	386

SELECTED QUARTERLY INFORMATION

(Unaudited)
In Millions, Except Per Share Amounts

Quarter ended:	Operating Revenues (a)	Operating Income	Net Income (Loss)	Earnings Per Common Share – Basic
March 31, 2002	$874	$111	$ 59	$ 0.42
March 31, 2001	927	116	58	0.43
June 30, 2002	978	194	115	0.80
June 30, 2001	928	145	95	0.69
September 30, 2002	1,166	297	240	1.64
September 30, 2001	1,206	311	267	1.94
December 31, 2002 (b)	823	21	(32)	(0.20)
December 31, 2001	797	93	49	0.35

(a) Revenues were netted with costs upon adoption of EITF 02-3 and the rescission of EITF 98-10. See Note 1 – Summary of Significant Accounting Policies for further information. The amount netted for each quarter is as follows: 2002 - $241 in first quarter, $133 in second quarter, $189 in third quarter, and $175 in fourth quarter (2001 - $98 in first quarter, $129 in second quarter, $225 in third quarter, and $196 in fourth quarter).

(b) Amounts include Voluntary Retirement and Other Restructuring Charges of $92 million ($58 million, net of taxes). See Note 9 - Voluntary Retirement and Other Restructuring Charges for further information.

Other impacts to quarterly earnings are due to the effect of weather on sales and other factors, including the 2002 Missouri rate order, that are characteristic of public utility operations.

AMEREN CORPORATION DIRECTORS AND OFFICERS AND PRINCIPAL OFFICERS OF KEY SUBSIDIARIES

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Vice President and Treasurer

Steven R. Sullivan
Vice President Regulatory Policy, General Counsel and Secretary

Martin J. Lyons
Vice President and Controller

AmerenUE

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Senior Vice President, Generation, and Chief Nuclear Officer

Ronald D. Affolter
Vice President, Nuclear

Charles D. Naslund
Vice President, Power Operations

AmerenCILCO

Gary L. Rainwater
President

Scott A. Cisel
Vice President and Chief Operating Officer

Robert G. Ferlmann
Vice President, Trading and Dispatch and Unregulated Sales

AmerenCIPS

Gary L. Rainwater
President and Chief Executive Officer

Ameren Services

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Senior Vice President, Energy Delivery

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Vice President, Energy Delivery Technical Services

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Vice President, Energy Delivery Gas Operations Support

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Vice President and Tax Counsel

J. Kay Smith
Vice President, Corporate Communications and Public Policy

Samuel E. Willis
Vice President, Industrial Relations

Ronald C. Zdellar
Vice President, Energy Delivery Distribution Services

AmerenEnergy

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President

Clarence J. Hopf, Jr.
Vice President

AmerenEnergy Resources

Daniel F. Cole
President

R. Alan Kelley
Senior Vice President, AmerenEnergy Generating

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Vice President

Michael G. Mueller
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Robert L. Powers
Vice President, AmerenEnergy Generating

Andrew M. Serri
Vice President, AmerenEnergy Marketing

Jerry L. Simpson
Vice President, AmerenEnergy Generating

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President and Chief Executive Officer – P. L. Miller and Associates, a management consulting firm

Charles W. Mueller [1, 5]
Chairman of the Board and Chief Executive Officer Ameren Corporation

Harvey Saligman [2]
Retired Managing Partner – Cynwyd Investments

James W. Wogsland [2]
Retired Vice Chairman – Caterpillar, Inc.

[1] *Member of Executive Committee*
[2] *Member of Auditing Committee*
[3] *Member of the Human Resources (compensation) Committee*
[4] *Member of the Nominating and Corporate Governance Committee*
[5] *Member of the Contributions Committee*

COMMON STOCK AND DIVIDEND INFORMATION

Ameren's common stock is listed on the New York Stock Exchange (ticker symbol: AEE). AEE began trading on January 2, 1998, following the merger of Union Electric Company and CIPSCO Incorporated on December 31, 1997.

Common stockholders of record totaled 96,437 for Ameren on December 31, 2002. The following includes the price ranges and dividends paid per common share for AEE during 2002 and 2001.

AEE 2002

Quarter Ended	High	Low	Close	Dividends Paid
March 31	$43.85	$39.50	$42.75	63½¢
June 30	45.20	40.20	43.01	63½
September 30	45.14	34.72	41.65	63½
December 31	42.69	38.75	41.57	63½

AEE 2001

Quarter Ended	High	Low	Close	Dividends Paid
March 31	$46.00	$37.31	$40.95	63½¢
June 30	45.48	40.20	42.70	63½
September 30	43.45	36.53	38.40	63½
December 31	42.90	37.80	42.30	63½

ANNUAL MEETING

The annual meetings of Ameren, Union Electric Company and Central Illinois Public Service Company stockholders will convene at 9 a.m., Tuesday, April 22, 2003, at Powell Symphony Hall, 718 North Grand Boulevard, St. Louis, Missouri. The annual meeting of Central Illinois Light Company stockholders will convene at 9 a.m., Tuesday, May 20, 2003, at Ameren headquarters, 1901 Chouteau Avenue, St. Louis, Missouri.

DRPLUS

Through DRPlus – Ameren's dividend reinvestment and stock purchase plan – any person of legal age or entity, whether or not an Ameren stockholder, is eligible to participate in DRPlus. Participants can:

- make cash investments by check or automatic direct debit to their bank accounts to purchase Ameren common stock, totaling up to $120,000 annually.
- reinvest their dividends in Ameren common stock or receive Ameren dividends in cash.
- place Ameren common stock certificates in safekeeping and receive regular account statements.

For more information about DRPlus, you may obtain a prospectus from the company's Investor Services representatives.

If you have not yet exchanged your Union Electric Company or CIPSCO Incorporated common stock certificates for Ameren stock certificates, please contact Investor Services. This is not an offer to sell, or a solicitation of an offer to buy, any securities.

DIRECT DEPOSIT OF DIVIDENDS

All registered Ameren common and Union Electric Company, Central Illinois Public Service Company and Central Illinois Light Company preferred stockholders can have their cash dividends automatically deposited to their bank accounts. This service gives stockholders immediate access to their dividend on the dividend payment date and eliminates the possibility of lost or stolen dividend checks.

AMEREN'S WEB SITE

To obtain AEE's daily stock price, recent financial statistics and other information about the company, or to sign up for electronic notification of company news and events, visit Ameren's home page on the Internet. Also included on our web site is the written charter of the Auditing Committee of the board. These materials are also available by writing Investor Services at the address shown below. Ameren's web site address is:

http://www.Ameren.com

INVESTOR SERVICES

The company's Investor Services representatives are available to help you each business day from 7:30 a.m. to 4:30 p.m. (Central Time).
Please write or call:

Ameren Services Company
Investor Services
P.O. Box 66887
St. Louis, MO 63166-6887
St. Louis area 314-554-3502
Toll-free 1-800-255-2237

TRANSFER AGENT, REGISTRAR AND PAYING AGENT

The Transfer Agent, Registrar and Paying Agent for Ameren Corporation common stock and Union Electric Company and Central Illinois Public Service Company preferred stock is Ameren Services Company. AmerenCILCO and Continental Stock Transfer are the transfer agents; National City Bank is the registrar; and AmerenCILCO is the paying agent for Central Illinois Light Company preferred stock.

OFFICE

Ameren Corporation
One Ameren Plaza
1901 Chouteau Avenue
St. Louis, MO 63103
314-621-3222

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