Union Electric

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March 8, 2000

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, D.C. 20555-0001

Gentlemen: ULNRC-04199

DOCKET NUMBER 50-483
CALLAWAY PLANT
UNION ELECTRIC COMPANY
ANNUAL FINANCIAL REPORT

Transmitted herewith are twenty-five (25) copies of the Ameren Corporation/ Union Electric Company 1999 Annual Report. This information is submitted in accordance with 10CFR50.71(b).

Very truly yours,

Alan C. Passwater
Manager, Corporate Nuclear Services

DES/mlo
Enclosure

M004
1/25

cc: M. H. Fletcher
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U.S. Nuclear Regulatory Commission
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focused on the future

1999 Annual Report

focused on

1999 FINANCIAL HIGHLIGHTS

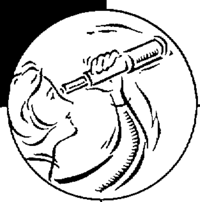
Ameren Consolidated	*Year Ended December 31, 1999*	*Current Year Change*
Earnings per Common Share	$2.81	–
Net Income	$385,095,000	–
Book Value per Common Share	$22.52	1%
Property and Plant (net)	$7,165,185,000	3%
Total Operating Revenues	$3,523,631,000	6%
Native Kilowatthour Sales	44,625,000,000	(1%)
Total Kilowatthour Sales	66,776,000,000	9%
Dividends Paid per Common Share	$2.54	–

WHO WE ARE: St. Louis-based Ameren Corporation (NYSE:AEE) provides energy services to 1.8 million customers in Missouri and Illinois. Approximately 93 percent of the company's $3.5 billion in revenues flows from electric sales, with the remainder primarily from sales of natural gas. Formerly Union Electric Company and CIPSCO Incorporated, Ameren prides itself on a long, successful tradition of financial strength, cost containment, low rates and continuous customer service improvements, as well as nine decades of uninterrupted cash dividend payments to stockholders.

the future

LOOKING AHEAD: We are focused on the opportunities of a more competitive environment as we capitalize on our low-cost generation and our strong marketing and energy trading skills. In addition, our solid financial position gives us much-needed flexibility in the capital markets during the transition to a competitive marketplace.

At Ameren, we can count on solid customer loyalty, built through a 97-year history of reliable, quality service. Our strategy for success can be summed up as follows: We optimize strong energy assets. We capitalize on our broad market reach. We deliver superior customer service and products. And we successfully leverage our proven financial and operating strengths to grow earnings and increase returns that directly benefit our owners.



To our owners,

LOOKING AHEAD: 1999 was a pivotal year for Ameren as we aggressively move forward to implement our strategic plan.

Utility operations remain our foundation, as we pursue four key strategies – all to return value to our shareholders:

We are aggressively expanding our generation business – a core company strength.

We are growing our customer base, primarily through our Illinois marketing efforts focused on building market share.

We are selectively investing in nonregulated ventures and creating innovative products to build competitive strengths that distinguish us in an increasingly competitive environment.

We continue to focus on controlling costs and effectively managing our regulatory affairs.

AGGRESSIVE GENERATION EXPANSION

We are adding more than 2,700 megawatts to our generating capacity through the addition of combustion turbine units. We are also placing most of this new generation and our existing AmerenCIPS plants into a nonregulated generating subsidiary. Nearly 600 megawatts of new Ameren generation will be available in 2000, with the balance available by 2005.

Charles W. Mueller
Chairman, President and
Chief Executive Officer

"We are committed to making the transition from a highly regulated utility to a growth-oriented energy company that will prosper in emerging competitive markets."

Ranking 17th in generation capacity in the nation, Ameren gains flexibility from combining the cost-effective use of coal-fired plants to cover baseload periods with natural gas-fired turbines to cover periods of peak energy demand. These new units will bring Ameren total generating capacity to more than 14,000 megawatts.

Thanks to AmerenEnergy, our energy trading and marketing subsidiary, the year also marked significant year-to-year interchange sales gains. Our more than 20 direct connections with power suppliers and the locations of our plants give Ameren a strategic position that is unmatched in the industry. That competitive advantage, coupled with strong performance from Ameren's power plants this summer, helped AmerenEnergy contribute 13 cents per share to the bottom line this year. However, AmerenEnergy did not enhance its performance at the expense of sound risk management. AmerenEnergy in 1999 earned recognition for its "prudent risk assessment models and conservative trading strategy" from Duff & Phelps Credit Rating Co., when they assigned a counterparty rating of "AA-" to AmerenEnergy.

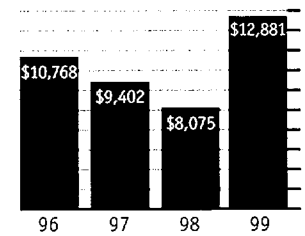
CUSTOMER GROWTH THROUGH STRONG SERVICE OFFERINGS

In the fall of 1999, approximately 15,000 of Ameren's large Illinois electric customers became eligible to choose among energy suppliers. We now have under contract a majority of our large Illinois electric customers who have the right to switch to other providers. We also achieved tremendous success outside our service territory, as evidenced by the recent signing of a multi-year contract with Illinois' largest electricity user – Archer Daniels Midland. In August 2000, Archer Daniels Midland will become a 300-megawatt customer of AmerenCIPS. Our utility company will be the sole power supplier for the international agricultural giant's Decatur, Ill.-based world headquarters and the nation's largest corn, soybean and bioproducts processing facility.

In addition, AmerenEnergy, as agent for AmerenCIPS, signed a multi-year contract with Soyland Power Cooperative for more than 375 megawatts of power. As part of the agreement, which took effect Jan. 1, 2000, AmerenEnergy will dispatch 178 megawatts of Soyland generating capacity.

In addition to being the largest supplier of electricity in Missouri with a 44 percent share of the market, we now hold 10 percent of the retail electric market share in Illinois; given our strong position, we believe provider choice in that state opens up opportunities for significant market share gains. In fact, we plan to use Illinois as a springboard for expansion in other midwestern markets as we build our generating capacity and exercise our strong marketing skills.

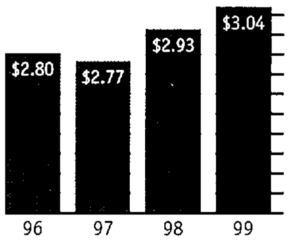
INTERCHANGE SALES GROWTH



(Kilowatthour sales in millions)

Interchange kilowatthour sales reflect energy sold to other energy providers; interchange sales rose significantly in 1999, thanks to skillful energy marketing and strong generation.

EARNINGS PER SHARE



Ongoing earnings per share represent reported earnings excluding nonrecurring items. Ongoing earnings per share for 1996 exclude merger-related costs of 9 cents. Ongoing earnings per share for 1997 exclude a net gain related to the capitalization of certain merger-related costs of 5 cents and a 38-cent extraordinary charge. Ongoing earnings per share for 1998 exclude an 11-cent charge for a targeted separation plan offered to employees whose positions were eliminated. Ongoing earnings per share for 1999 exclude a charge of 23 cents, due to the termination of coal contracts.

INNOVATIVE PRODUCTS, NONREGULATED VENTURES

Linked to Ameren's success with products like its automated bill consolidation service – Ameren Abillity – and its popular Internet-based energy management product, Ameren Abacus, is another promising nonregulated business: In 1999, Ameren acquired California-based Data and Metering Specialties, Inc. (DMS) – a multi-state provider of metering products and services. Coupled with Ameren's position as the company with the world's largest network of automated meters, the creation of AmerenDMS offers a valuable platform for increased revenue as demand for competitive metering services grows.

We also continue to selectively pursue other nonregulated, high-return investment opportunities. We have a promising investment in Gateway Energy Systems, a firm that designs, builds, finances, owns and operates utility systems for large institutional and industrial customers. For Gateway Energy, the year marked the completion of a $20 million steam and compressed air facility for the Fortune 500 chemical manufacturer, Solutia Inc.

CONTINUED FOCUS ON CONTROLLING COSTS, MANAGING REGULATION

We continue to hold employees accountable for expense control through value-based financial measures and incentives. In 1999, we took aggressive steps to reduce our fuel costs through the termination of coal contracts with two coal suppliers for AmerenCIPS plants – resulting in net savings of $131 million through 2010. These net savings will benefit our shareholders.

On the regulatory side, we continue to manage regulatory and legislative uncertainties, with an eye toward shaping electric customer choice legislation as it is implemented in Illinois and considered in Missouri. Ameren is actively taking steps to build a coalition to support restructuring legislation as long as that legislation is fair and equitable to shareholders, customers and employees. We believe that, with momentum building across the nation for choice, the sooner restructuring issues are satisfactorily resolved in Missouri, the better it will be for all stakeholders.

Finally, in 1999, Ameren joined other industrial companies to successfully challenge the Environmental Protection Agency on its stringent new emissions rules. We continue to press for cost-effective, prudent responses to environmental controls. At Ameren, we remain committed to providing clean, low-cost energy, while preserving and protecting the environment.

1999 FINANCIAL PERFORMANCE

In 1999, our company earned $385 million, or $2.81 per share. This compares to 1998 earnings of $386 million, or $2.82 per share. In 1999, we reported a pretax nonrecurring charge of $52 million, or 23 cents per share, due to the payments required for terminating coal contracts to our future benefit. In 1998, we reported a pretax nonrecurring charge of $25 million, or 11 cents per share, from the implementation of a targeted employee separation plan. Excluding these nonrecurring charges and the impacts of weather, we were able to deliver a strong 8 percent increase in earnings per share in 1999 over 1998. Looking ahead, we are targeting annual earnings per share growth of at least 5 percent.

Ameren's Senior Management Team: (from left) Thomas R. Voss, Senior Vice President; Gary L. Rainwater, AmerenCIPS President and Chief Executive Officer; and Senior Vice Presidents, Daniel F. Cole, Paul A. Agathen and Donald E. Brandt.

IN SUMMARY

We are committed to making the transition from a highly regulated utility to a growth-oriented energy company that will prosper in emerging competitive markets. Our mission reflects a strategic decision to pursue scale and scope, rather than retreat to a narrowly defined business. And our course is clear: We will aggressively expand and optimize our generating assets. We will leverage our strong marketing skills and quality to expand our customer base, while we selectively invest in nonregulated ventures and innovative products. And, we will continue to control costs and effectively manage our regulatory affairs.

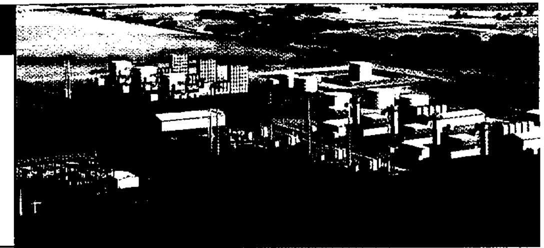
We believe pursuing these strategies paves the way for sustainable growth. Going forward, we intend to be our customers' preferred supplier. We intend to remain a strong investment choice. We intend to be an industry leader. And, most important, we intend to press forward in our efforts to return superior shareholder value to you – our owners.

Sincerely,

Charles W. Mueller

Chairman, President and Chief Executive Officer

February 10, 2000



energy

LOOKING AHEAD: The nation's 17th largest in generating capacity, Ameren is wringing even more efficiency out of its existing units while planning for additional capacity.

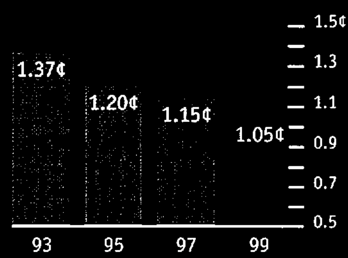
Ameren holds a strategic position in an economically strong region. Our plans call for moving the AmerenCIPS plants into a nonregulated subsidiary, along with more than 2,500 megawatts of new capacity from planned combustion turbines (like the one shown above). This generating company will bring shareholders direct benefits from a number of initiatives, including switching the fuel for the Newton Plant to low-cost Western coal. A new stacker-reclaimer at the plant (right) now builds piles of low-sulfur coal at a rate of 3,000 tons an hour. When reversed, it reclaims, or scoops up, coal at 2,500 tons an hour, and the coal then goes into the plant. In 1999 generation upgrades improved efficiency and added capacity to the Missouri plants – investments that kept plants generating at the highest possible levels.

AmerenUE's Labadie Plant is a national leader in economically generating power. In 1999, the plant installed digital controls that improve boiler efficiency, reduce nitrogen oxide emissions and lower maintenance costs. At right, Russ Hawkins (left) and Donald Greenlee, (foreground) both operating supervisors, use highly automated control systems, developed and installed by employee teams.

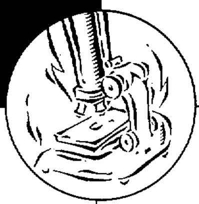
Jerry Simpson, Vice President, Power Operations, AmerenCIPS

"With some of the lowest embedded costs in the industry, our plants can effectively compete in Illinois – especially with initiatives in place for reducing costs even more."

FUEL COSTS



(average cost per kilowatthour hour)



reach

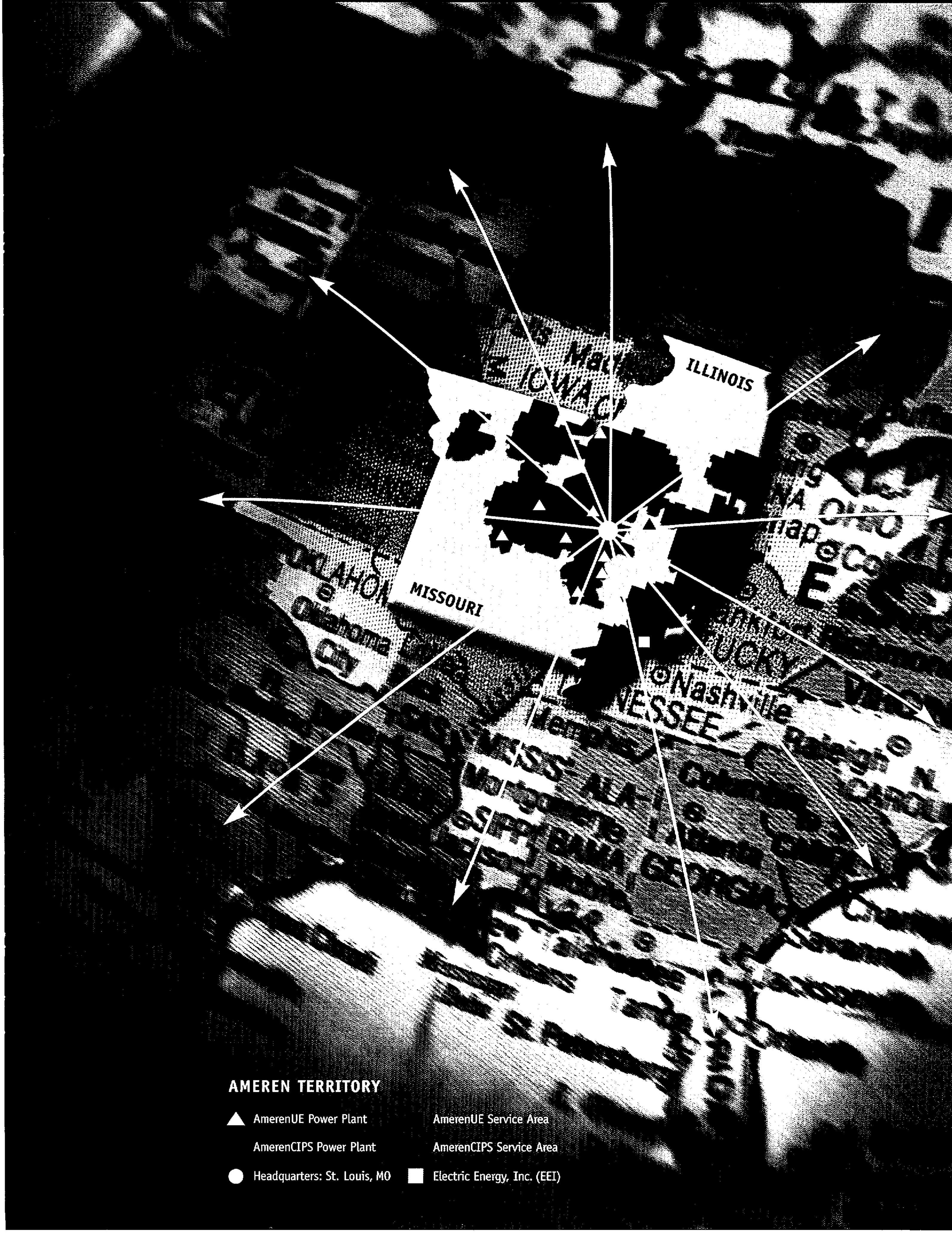
LOOKING AHEAD: Moving forward, we are capitalizing on an extensive transmission system and multiple direct ties to other energy providers – both distinguish Ameren from its competitors.

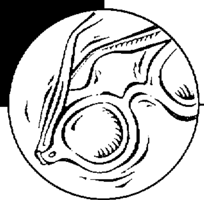
At Ameren, we are optimizing generating assets through profitable energy trading and conservative risk management, in addition to creating a nonregulated Illinois generating company. We are increasing our share of competitive energy markets in Illinois – signing contracts with new electric customers and expanding our natural gas business. Our more than 20 connections with other power suppliers make Ameren one of the most interconnected of any supplier in the nation. Our primary purpose at AmerenEnergy is to maximize the value and to conservatively manage the risk of our generation portfolio. We did that very effectively this summer when for the second consecutive year, a heat wave – plus regional energy shortages – sent electricity prices soaring.

Serving the needs of 660,000 metro area St. Louis customers, a new transmission line extension went into service in 1999. At right, a helicopter delivers a section of a 326-foot steel tower for a 12.6-mile extension, linking AmerenUE's Sioux Plant in Missouri to an Illinois substation.

Lee Wilmes, Vice President, Planning and Rates, Soyland Power Cooperative

"A new contract between AmerenEnergy and Soyland Power Cooperative allows Soyland to make the most of its generating assets, while giving the cooperative longer-term price certainty."


ILLINOIS
MISSOURI
AMEREN TERRITORY
AmerenUE Power Plant
AmerenCIPS Power Plant
Headquarters: St. Louis, MO
AmerenUE Service Area
AmerenCIPS Service Area
Electric Energy, Inc. (EEI)



service

LOOKING AHEAD: The company is expanding its relationship with key customers by providing a range of energy management tools and sophisticated wireless metering products.

Whether promoting our brand name before St. Louis Blues Hockey fans (above) or serving Schnucks Markets, Inc. stores (right), Ameren focuses on quality. For Schnucks Markets, like this handsome superstore in Richmond Heights, Mo., AmerenUE offers services that range from maintenance of distribution equipment to energy management advice. And for the Schnucks' dairy, the company offers Ameren Abacus, which allows Schnucks' management to closely monitor energy use within each building, department or production process and to receive usage reports via the Internet. In another initiative, AmerenUE installed its 1.2 millionth automated meter in 1999 to create the world's largest network meter system. Using that system as a springboard, Ameren in 1999 acquired the California-based Data and Metering Specialties, Inc., to create a multi-state metering company – now called AmerenDMS.

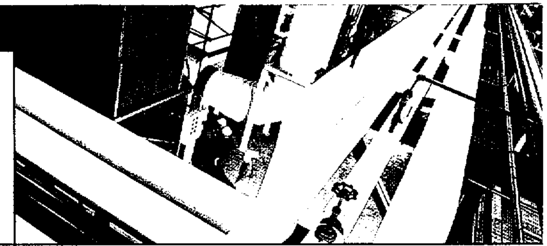
Shopping centers, like the Westfield Shoppingtown's Valley Fair Mall in San Jose, California, at right, are among 37 mall customers of AmerenDMS, a full-service provider of metering services. The creation of AmerenDMS positions our corporation for growth in this sector as industry restructuring opens metering services to competition in many states.

Alan Potts, the AmerenCIPS Key Account Executive, responsible for the ADM relationship

"A tangible demonstration of our strong service and reliability came when Archer Daniels Midland, a Fortune 100 agricultural giant, signed a multi-year contract with AmerenCIPS."

AVERAGE COMPETITIVE RATES – TOTAL RETAIL

*At June 30, 1999 – Edison Electric Institute



strength

LOOKING AHEAD: Ameren's strong financial position, reflected in solid credit ratings and consistent earnings growth, serves as a foundation for building both regulated and nonregulated businesses.

Supporting Ameren's ability to grow is the company's financial flexibility – our low debt-to-equity ratio and solid cash flows. Also bolstering growth is our position in stable regional economies strengthened by the presence of the Big Three automakers. The St. Louis area ranks just behind Detroit in production thanks to operations like the Daimler-Chrysler plant and products like the Dodge Ram Quad Cab (shown at right). On the nonregulated side of our business, Ameren's joint venture, Gateway Energy Systems, completed a $20 million steam and compressed air plant for Fortune 500 chemical manufacturer Solutia Inc., at Solutia's W. G. Krummrich Plant in Sauget, Ill. (shown above). Gateway Energy's comprehensive services include project financing, design, construction, operation and facility maintenance.

At right, Pressman Harland Tinsman oversees production while stationed at the recently installed, highly automated Harris M1000B press at the magazine printing plant of R.R. Donnelly – a valued AmerenCIPS customer since 1968.

Joseph Kingan, Vice President and Division Director, Mattoon Manufacturing Division, R.R. Donnelly & Sons Company

"Because efficient use of electricity is critical to commercial printing and information services giant R.R. Donnelly, our Mattoon, Ill., magazine printing plant relies heavily on AmerenCIPS' service."


MEL
DaimlerChrysler

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 generally accepted accounting principles. 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, President and Chief Executive Officer
February 2, 2000

Donald E. Brandt
Senior Vice President, Finance
February 2, 2000

Report of Independent Accountants

To the Stockholders and Board of Directors of Ameren Corporation:

In our opinion, based upon our audits and the report of other auditors, the accompanying consolidated balance sheet and the related consolidated statements of income and retained earnings and of cash flows appearing on pages 23-27 of this annual report present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with generally accepted accounting principles in the United States. 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 did not audit the financial statements of Central Illinois Public Service Company and CIPSCO Investment Company, wholly-owned subsidiaries of Ameren Corporation, for the year ended December 31, 1997, which combined statements reflect total revenues of $863,441,000 for the year ended December 31, 1997. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for Central Illinois Public Service Company and CIPSCO Investment Company for the year ended December 31, 1997, is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with generally accepted auditing standards in the United States, 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 and the report of other auditors provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 2, 2000

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

Overview

Ameren Corporation (Ameren) is a holding company registered under the Public Utility Holding Company Act of 1935 (PUHCA). In December 1997, Union Electric Company (AmerenUE) and CIPSCO Incorporated (CIPSCO) combined to form Ameren, with AmerenUE and CIPSCO's subsidiaries, Central Illinois Public Service Company (AmerenCIPS) and CIPSCO Investment Company (CIC), becoming subsidiaries of Ameren (the Merger). As a result of the Merger, Ameren has a 60% ownership interest in Electric Energy, Inc. (EEI). That interest is consolidated for financial reporting purposes. Since the Merger, Ameren has formed AmerenEnergy, Inc. (AmerenEnergy), Ameren Development Company, Ameren Intermediate Holding Company, Inc., and Ameren Services Company. AmerenEnergy, an energy marketing subsidiary, primarily serves as a power marketing agent for the operating utility subsidiaries and provides a range of energy and risk management services to targeted customers. Ameren Development Company is a nonregulated subsidiary encompassing Ameren's nonregulated products and services. Ameren Intermediate Holding Company, Inc. is a holding company for the proposed Illinois nonregulated generating subsidiary and its proposed marketing affiliate (see discussion below under "Electric Industry Restructuring – Illinois" and Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). Ameren Services Company provides shared support services to Ameren and all of its subsidiaries.

The Merger was accounted for as a pooling of interests; therefore, the consolidated financial statements are presented as if the Merger were consummated as of the beginning of the earliest period presented. However, the consolidated financial statements are not necessarily indicative of the results of operations, financial position or cash flows that would have occurred had the Merger been consummated for the periods for which it is given effect, nor is it necessarily indicative of the future results of operations, financial position or cash flows.

References to the Company are to Ameren on a consolidated basis; however, in certain circumstances, the subsidiaries are separately referred to in order to distinguish between their different business activities.

Results of Operations

EARNINGS

Earnings for 1999, 1998 and 1997, were $385 million ($2.81 per share), $386 million ($2.82 per share) and $335 million ($2.44 per share), respectively. Earnings and earnings per share fluctuated due to many conditions, primarily: sales growth, weather variations, credits to electric customers, electric rate reductions, gas rate increases, competitive market forces, fluctuating operating costs (including Callaway Nuclear Plant refueling outages), charges for coal contract terminations and a targeted employee separation plan, merger-related expenses, changes in interest expense, changes in income and property taxes, and an extraordinary charge.

In the fourth quarter of 1999, the Company recorded a nonrecurring charge to earnings in connection with coal contract terminations with two coal suppliers. The charge reduced earnings $31 million, net of income taxes, or 23 cents per share (see discussion below under "Electric Operations" and Note 12 - Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). In 1998, the Company also recorded a nonrecurring charge to earnings in connection with a targeted separation plan it offered to employees in July 1998. That charge reduced earnings $15 million, net of income taxes, or 11 cents per share (see Note 3 – Targeted Separation Plan under Notes to Consolidated Financial Statements for further information). In addition, the Company recorded an extraordinary charge to earnings in the fourth quarter of 1997 for the write-off of generation-related regulatory assets and liabilities of the Company's Illinois retail electric business as a result of electric industry restructuring legislation enacted in Illinois in December 1997. The write-off reduced earnings $52 million, net of income taxes, or 38 cents per share (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information).

The significant items affecting revenues, expenses and earnings for the years ended December 31, 1999, 1998 and 1997 are detailed in the following pages.

ELECTRIC OPERATIONS

Electric Revenues

	Variations from Prior Year		
In Millions	*1999*	*1998*	*1997*
Rate variations	$ (17)	$(13)	$ –
Credit to customers	5	(24)	28
Effect of abnormal weather	(53)	61	3
Growth and other	57	45	5
Interchange sales	177	16	(43)
EEI sales	24	(55)	9
	$193	$ 30	$ 2

Electric revenues for 1999 increased $193 million, compared to 1998, primarily due to a 9% increase in total kilowatthour sales. This increase was primarily driven by a 60% increase in interchange sales, due to strong marketing efforts by AmerenEnergy, and a 12% increase in EEI sales. Also contributing to the revenue increase was a decrease in the credit to Missouri electric customers, partially offset by the credit to Illinois electric customers (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). Partially offsetting these increases, weather-sensitive residential and commercial sales decreased 2% and 1%, respectively, while industrial sales remained flat. In addition, revenues were lower due to rate decreases in both Missouri and Illinois (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information).

Electric revenues for 1998 increased $30 million, compared to 1997. Revenues increased primarily due to higher sales to retail customers within the Company's service territory, as a result of warm summer weather and economic growth in the service area. Weather-sensitive residential and commercial sales increased 6% and 4%, respectively, while industrial sales grew 2%. Additionally, interchange revenues increased 7%, despite a 14%

decline in interchange sales, due to market conditions. These increases were partially offset by an increase in credits to Missouri electric customers (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information) and lower sales by EEI.

Electric revenues for 1997 were flat compared to 1996, reflecting a decrease in the Missouri electric customer credits recorded in 1997, versus 1996 (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information), partly offset by a 1% decrease in kilowatthour sales. The kilowatthour sales decrease was due to a 13% decrease in interchange sales, due to market conditions; a 1% decline in residential sales; and differences in the classification of certain interchange and purchased power transactions, resulting from the Federal Energy Regulatory Commission (FERC) Order 888. These decreases were partly offset by increases in commercial and industrial sales of 1% and 2%, respectively, attributable to economic growth. In addition, sales at EEI were up 6% over 1996.

Fuel and Purchased Power

	Variations from Prior Year		
In Millions	*1999*	*1998*	*1997*
Fuel:			
Generation	$ 10	$ 9	$ 25
Price	(15)	(23)	(24)
Generation efficiencies and other	(8)	–	(5)
Coal contract termination payments	52	–	–
Purchased power	117	(3)	(50)
EEI	37	(39)	10
	$193	$(56)	$(44)

The $193 million increase in fuel and purchased power costs for 1999, compared to 1998, was primarily due to increased generation and purchased power, resulting from higher sales volume, increased fuel and purchased power costs at EEI and coal contract termination payments discussed below, partially offset by lower fuel costs.

In the fourth quarter of 1999, AmerenCIPS and two of its coal suppliers executed agreements to terminate their existing coal supply contracts effective December 31, 1999. Under these agreements, AmerenCIPS made termination payments to the suppliers totaling approximately $52 million. These termination payments were recorded as a nonrecurring charge in the fourth quarter of 1999. Total pretax fuel cost savings from these termination agreements are estimated to be $183 million (or $131 million net of the termination payments) through 2010, which is the maximum period that would have remained on any of the terminated coal supply contracts. Approximately $66 million of pretax fuel cost savings is expected to be realized over the next three years. See Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information.

The $56 million decrease in fuel and purchased power costs for 1998, compared to 1997, was primarily driven by lower fuel and purchased power costs at EEI as a result of fewer sales. In addition, fuel cost reductions were realized due to lower fuel prices, as well as through the joint dispatch of generation. Upon consummation of the Merger, AmerenUE and AmerenCIPS began jointly dispatching generation, therefore allowing the Company to utilize the most cost efficient plants of both operating companies to serve customers in either service territory. These decreases were partially offset by increased generation to serve native load demand. The decrease in 1997 fuel and purchased power costs was primarily due to reduced purchased power costs, resulting from relatively flat native load sales and lower interchange sales, as well as lower fuel prices, offset by greater generation.

GAS OPERATIONS

Gas revenues in 1999 increased $12 million, compared to 1998, primarily due to Illinois gas rate increases which became effective in February 1999 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information) and higher gas costs recovered through the Company's purchased gas adjustment clauses. These increases were partially offset by an 8% decline in retail sales, resulting primarily from milder weather, as well as a decrease in off-system sales of gas to others. Gas revenues in 1998 decreased $33 million, compared to 1997, primarily due to an 8% decline in retail sales resulting from milder winter weather and lower gas costs reflected in the Company's purchased gas adjustment clauses. These decreases were partially offset by benefits realized from a Missouri gas rate increase effective February 1998 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). Gas revenues in 1997 decreased $4 million, primarily due to a 12% decrease in retail sales. Milder winter weather resulted in a decline in weather-sensitive residential and commercial sales of 15% and 18%, respectively. These decreases were partly offset by a 20% increase in industrial sales and an increase in off-system sales of gas to others.

Gas costs in 1999 increased $13 million compared to 1998. This increase in gas costs was primarily due to higher gas prices, partially offset by lower total sales. Gas costs in 1998 declined $42 million, compared to 1997, due to lower sales and lower gas prices. Gas costs for 1997 remained flat, as compared to those of 1996.

OTHER OPERATING EXPENSES

Other operating expense variations in 1997 through 1999 reflected recurring factors such as growth, inflation, labor and benefit increases, in addition to the capitalization of certain costs as a result of a Missouri Public Service Commission (MoPSC) Order and a charge for the targeted employee separation plan (TSP), as discussed below.

In 1998, the Company announced plans to reduce its other operating expenses, including plans to eliminate approximately 400 employee positions by mid-1999 through a hiring freeze and the TSP. During the third quarter of 1998, a nonrecurring, pretax charge of $25 million was recorded, representing costs incurred to implement the TSP. The elimination of these positions, exclusive of the nonrecurring charge, reduced the Company's operating expenses approximately $15 million in 1998, and approximately $22 million in 1999, and is expected to reduce the Company's operating expenses by approximately $20 million to $25 million each year thereafter. See Note 3 – Targeted Separation Plan under Notes to Consolidated Financial Statements for further information.

Other operating expenses decreased $18 million in 1999, compared to 1998. This decrease was primarily due to the 1998 charge for the TSP and related reduced workforce and the capitalization of certain costs (including computer software costs) that had previously been expensed for the Company's Missouri electric operations. The capitalization was a result of the MoPSC Order received in December 1999 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). These decreases were partially offset by current year expenses associated with electric industry deregulation in Illinois. The $62 million increase in other operations expense in 1998, compared to 1997, was primarily due to the charge for the TSP and increases in injuries and damages expense and information system-related costs. In 1997, other operations expenses increased $41 million, primarily due to increases in information system-related costs, labor, and injuries and damages expenses.

Maintenance expenses increased $59 million in 1999, compared to 1998. This increase was primarily due to increased power plant maintenance and tree-trimming activity. The expenses incurred for the 35-day refueling outage in the fall of 1999 at the Callaway Nuclear Plant were comparable to those for the 31-day spring 1998 refueling outage. No refueling outage is scheduled for 2000. Maintenance expenses increased $2 million in 1998, compared to 1997, due to the refueling outage at the Callaway Nuclear Plant, partially offset by less scheduled fossil power plant maintenance. Maintenance expenses for 1997 increased $8 million, primarily resulting from increased scheduled fossil plant maintenance, partly offset by decreased expenses at the Callaway Plant due to the absence of a refueling outage in 1997.

Depreciation and amortization expense was relatively flat in 1999 and 1998, compared to the prior year periods. Depreciation and amortization expense increased $7 million in 1997, due to increased depreciable property.

TAXES

Income tax expense from operations decreased $9 million in 1999, compared to 1998, due to lower pretax income. Income tax expense from operations increased $33 million in 1998, compared to 1997, due to higher pretax income and a higher effective tax rate. Income tax expense from operations decreased $19 million in 1997, principally due to lower pretax income and a lower effective tax rate.

Other tax expense decreased $26 million in 1999, compared to 1998, primarily due to a decrease in gross receipts taxes related to the Company's Illinois jurisdiction. This decrease is the result of the restructuring of the Illinois public utility tax whereby gross receipts taxes are no longer recorded as electric revenues and gross receipts tax expense.

OTHER INCOME AND DEDUCTIONS

Miscellaneous, net increased $8 million, compared to 1998, primarily due to the write-off of certain nonregulated investments in 1999 and gains on the sale of property realized in 1998 but not in 1999. Miscellaneous, net decreased $8 million for 1998, compared to 1997, due to increased interest income and gains on the sale of property. Miscellaneous, net decreased $11 million for 1997, compared to 1996, primarily due to the capitalization of certain merger-related costs in 1997 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information).

INTEREST

Interest expense decreased $13 million in 1999, primarily due to a lower amount of debt outstanding throughout the year. Interest expense decreased $4 million in 1998, compared to 1997, due to lower interest rates and a decrease in other interest expense, partially offset by an increase in interest on a higher amount of debt outstanding. Interest expense increased $5 million in 1997, primarily due to higher debt outstanding during the year at higher interest rates.

BALANCE SHEET

The $22 million increase in trade accounts receivable and unbilled revenue was due primarily to higher sales and revenues in November and December 1999, compared to the same 1998 period. The $20 million decrease in accounts receivable and unbilled revenues at December 31, 1998, compared to 1997, was due to lower sales and revenues in November and December 1998, compared to the same 1997 time period, due to mild winter weather.

The $84 million increase in other current liabilities was primarily due to the timing of credit payments to electric customers in the Company's Missouri and Illinois jurisdictions, as well as an increase in a liability for an estimated rate reduction for Missouri electric customers retroactive to September 1, 1998 (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). The remaining variance is a result of the timing of various payments to suppliers.

Liquidity and Capital Resources

Cash provided by operating activities totaled $918 million for 1999, compared to $803 million for 1998 and $708 million for 1997.

Cash flows used in investing activities totaled $558 million, $323 million and $387 million, for the years ended December 31, 1999, 1998 and 1997, respectively. Expenditures in 1999 for constructing new or improving existing facilities and purchasing rail cars were $571 million. In addition, the Company spent $22 million to acquire nuclear fuel.

Capital expenditures are expected to approximate $749 million in 2000. For the five-year period 2000 through 2004, construction expenditures are estimated at $3.3 billion. This estimate includes capital expenditures of approximately $1 billion for the purchase of new combustion turbines (CTs) (see Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information), as well as expenditures that will be incurred by the Company to meet new air quality standards for ozone and particulate matter, as discussed below.

Title IV of the Clean Air Act Amendments of 1990 requires the Company to significantly reduce total annual sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions by the year 2000. By switching to low-sulfur coal, early banking of emission credits and installing advanced NOx reduction combustion technology, the Company is meeting these requirements.

In July 1997, the United States Environmental Protection Agency (EPA) issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. In May 1999, the U.S. Court of Appeals for the District of Columbia remanded the regulations back to the EPA for review. Litigation regarding appeals of these regulations is ongoing. New ambient standards may result in significant additional reductions in SO2 and NOx emissions from the Company's power plants by 2007. At this time, the Company is unable to predict the ultimate impact of these revised air quality standards on its future financial condition, results of operations or liquidity.

In an attempt to lower ozone levels across the eastern United States, the EPA issued the implementation of regulations in September 1998 to reduce NOx emissions from coal-fired boilers and other sources in 22 states, including Missouri and Illinois (where all of the Company's coal-fired power plant boilers are located). The implementation of these regulations has been delayed by the U.S. Court of Appeals for the District of Columbia until a legal challenge brought by various industries and states has been resolved. The proposed regulations mandate a 75% reduction from 1990 levels by the year 2003 and require states to develop plans to reduce NOx emissions to help alleviate ozone problem areas. The NOx emissions reductions already achieved on several of the Company's coal-fired power plants will help to reduce the costs of compliance with these regulations. However, preliminary analysis of the regulations indicate that selective catalytic reduction technology may be required for some of the Company's units, as well as other additional controls.

Currently, the Company estimates that its additional capital expenditures to comply with the final NOx regulations could range from $250 million to $300 million over the period from 1999 to 2003. Associated operations and maintenance expenditures could increase $10 million to $15 million annually, beginning in 2003. The Company is exploring alternatives to comply with these new regulations in order to minimize, to the extent possible, its capital costs and operating expenses. The Company is unable to predict the ultimate impact of these standards on its future financial condition, results of operations or liquidity.

In November 1998, the United States signed an agreement with numerous other countries (the Kyoto Protocol) containing certain environmental provisions, which would require decreases in greenhouse gases in an effort to address the "global warming" issue. The Kyoto Protocol has not been ratified by the United States Senate. Implementation of the Kyoto Protocol in its present form would likely result in significantly higher capital costs and operations and maintenance expenses by the Company. At this time, the Company is unable to determine the impact of these proposals on the Company's future financial condition, results of operations or liquidity.

See Note 13 - Callaway Nuclear Plant under Notes to Consolidated Financial Statements for a discussion of Callaway Plant decommissioning costs.

Cash flows used in financing activities were $241 million for 1999, compared to $446 million for 1998 and $302 million for 1997. The Company's principal financing activities during 1999 included the issuance of $210 million of long-term debt, the redemption of $174 million of long-term debt and the payment of dividends.

The Company plans to continue utilizing short-term debt to support normal operations and other temporary requirements. The Company and its subsidiaries are authorized by the Securities and Exchange Commission (SEC) under PUHCA to have up to an aggregate $2.8 billion of short-term unsecured debt instruments outstanding at any one time. Short-term borrowings consist of bank loans (maturities generally on an overnight basis) and commercial paper (maturities generally within 10 to 45 days). At December 31, 1999, the Company had committed bank lines of credit aggregating $180 million, all of which was unused and available at such date, which make available interim financing at various rates of interest based on LIBOR, the bank certificate of deposit rate or other options. The lines of credit are renewable annually at various dates throughout the year. The Company has bank credit agreements, expiring at various dates between 2000 and 2003, that support commercial paper programs totaling $800 million, $500 million of which is available for the Company's own use and for the use of its subsidiaries. The remaining $300 million is available for the use of the Company's regulated subsidiaries. At December 31, 1999, $520 million was unused and available. The Company had $80 million of short-term borrowings outstanding at year-end.

AmerenUE also has a lease agreement that provides for the financing of nuclear fuel. At December 31, 1999, the maximum amount that could be financed under the agreement was $120 million. Cash used in financing for 1999 included issuances under the lease for nuclear fuel of $65 million, offset in part by $15 million of redemptions. At December 31, 1999, $116 million was financed under the lease. See Note 5 - Nuclear Fuel Lease under Notes to Consolidated Financial Statements for further information.

The Company, in the ordinary course of business, explores opportunities to reduce its costs in order to remain competitive in the marketplace. Areas where the Company focuses its review include, but are not limited to, labor costs and fuel supply costs. In the labor area, the Company has recently reached agreements with many of the Company's major collective bargaining units which will permit it to manage its labor costs and practices effectively in the future. The Company also explores alternatives to effectively manage the size of its workforce. These alternatives include utilizing hiring freezes, outsourcing and offering employee separation packages. In the fuel supply area, the Company explores alternatives to effectively manage its overall fuel costs. These alternatives include diversifying fuel sources for use at the Company's fossil power plants (e.g. utilizing low-sulfur versus high-sulfur coal), as well as restructuring or terminating existing contracts with suppliers.

Certain of these reduction alternatives could result in additional investments being made at the Company's power plants in order to utilize different types of coal, or could require nonrecurring payments of employee separation benefits or nonrecurring payments to restructure or terminate existing fuel contracts with a supplier. Management is unable to predict which (if any), and to what extent, these alternatives to reduce its overall cost structure will be executed. Management is unable to determine the impact of these actions on the Company's future financial position, results of operations or liquidity.

Dividends

Common stock dividends paid in 1999 resulted in a payout rate of 90% of the Company's net income. Dividends paid to common stockholders in relation to net cash provided by operating activities for the same period were 38%.

The Board of Directors does not set specific targets or payout parameters for dividend payments; however, the Board considers various issues including the Company's 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 11, 2000, the Ameren Board of Directors declared a quarterly common stock dividend of 63.5 cents per share, payable March 31, 2000.

Rate Matters

See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for a discussion of rate matters.

Electric Industry Restructuring

Steps taken and being considered at the federal and state levels continue to change the structure of the electric industry and utility regulation, and encourage increased competition. At the federal level, the Energy Policy Act of 1992 reduced various restrictions on the operation and ownership of independent power producers and gave the FERC the authority to order electric utilities to provide transmission access to third parties.

In April 1996, the FERC issued Order 888 and Order 889, which are intended to promote competition in the wholesale electric market. The FERC requires transmission-owning public utilities, such as AmerenUE and AmerenCIPS, to provide transmission access and service to others in a manner similar and comparable to that which the utilities have by virtue of ownership. Order 888 requires that a single tariff be used by the utility in providing transmission service. Order 888 also provides for the recovery of strandable costs, under certain conditions, related to the wholesale business.

Order 889 established the standards of conduct and information requirements that transmission owners must adhere to in doing business under the open access rule. Under Order 889, utilities must obtain transmission service for their own use in the same manner their customers will obtain service, thus mitigating market power through control of transmission facilities. In addition, under Order 889, utilities must separate their merchant function (buying and selling wholesale power) from their transmission and reliability functions.

The Company believes that Order 888 and Order 889, which relate to its wholesale business, will not have a material adverse effect on its financial condition, results of operations or liquidity.

In 1998, Ameren's operating utility subsidiaries joined a group of companies that support the formation of the Midwest Independent System Operator (Midwest ISO). An ISO operates, but does not own, electric transmission systems and maintains system reliability and security, while alleviating pricing issues associated with the "pancaking" of rates. The Midwest ISO would be regulated by the FERC. Thirteen transmission-owning utilities have joined the Midwest ISO as of December 31, 1999. The FERC conditionally approved the formation of the Midwest ISO in September 1998, and it is expected to be operational during the year 2001. The MoPSC and the Illinois Commerce Commission (ICC) have authorized AmerenUE and AmerenCIPS to join the Midwest ISO and to transfer control of their transmission facilities to the Midwest ISO. The Midwest ISO covers 14 states, represents portions of 60,000 miles of transmission line and controls $8 billion of assets. The Company believes that the operation of the Midwest ISO will not have a material adverse effect on its financial condition, results of operations or liquidity.

In December 1999, the FERC issued Order 2000 relating to Regional Transmission Organizations (RTOs) that would meet certain characteristics such as size and independence. Order 2000 calls on all transmission owners to join RTOs. In particular, all public utilities that own, operate, or control interstate transmission facilities must file with the FERC by October 15, 2000, a proposal for an RTO, or alternatively a description of efforts by the utility to join an RTO. The Company expects that its participation in the Midwest ISO will satisfy the requirements of Order 2000.

ILLINOIS

Certain states are considering proposals or have adopted legislation that will promote competition at the retail level. In December 1997, the Governor of Illinois signed the Electric Service Customer Choice and Rate Relief Law of 1997 (the Illinois Law) providing for electric utility restructuring in Illinois. This legislation introduces competition into the supply of electric energy at retail in Illinois.

Major provisions of the Illinois Law include the phasing-in through 2002 of retail direct access, which allows customers to choose their electric generation suppliers. The phase-in of retail direct access began on October 1, 1999, with large commercial and industrial customers principally comprising the initial group. The customers in this group represent approximately 10% of the Company's total sales. As of December 31, 1999, the impact of retail direct access on the Company's financial condition, results of operations or liquidity was immaterial. Retail direct access will be offered to the remaining commercial and industrial customers on December 31, 2000, and to residential customers on May 1, 2002.

In addition, the Illinois Law included a 5% rate decrease for residential customers that became effective in August 1998. This rate decrease reduced electric revenues $8 million in 1999 compared to 1998 and is expected to impact electric revenues by approximately $14 million annually, based on estimated levels of sales and assuming normal weather conditions. (See Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). In 1998, the Company eliminated its Uniform Fuel Adjustment Clauses (FACs) as allowed by the Illinois Law, which benefited shareholders in 1998 and 1999 and is expected to benefit shareholders in the future (see Note 1 – Summary of Significant Accounting Policies under Notes to Consolidated Financial Statements for further information). The Illinois Law contains a provision allowing for the potential recovery of a portion of strandable costs, which represent costs that would not be recoverable in a restructured environment, through a transition charge collected from customers who choose an alternate electric supplier. In addition, the Illinois Law contains a provision requiring a portion of excess earnings (as defined under the Illinois Law) for the years 1998 through 2004 to be refunded to customers. As of December 31, 1999, the Company recorded an estimated $5 million credit it expects to return to its Illinois customers under the Illinois Law for the two-year period ended December 31, 1999. See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

In December 1997, after evaluating the impact of the Illinois Law, the Company determined that it was necessary to write-off the generation-related regulatory assets and liabilities of its Illinois retail electric business. This extraordinary charge reduced 1997 earnings $52 million, net of income taxes, or 38 cents per share. The Company has also concluded that its remaining net generation-related assets are not impaired for financial reporting purposes and that no plant writedowns are necessary at this time. See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

In conjunction with another provision of the Illinois Law, in July 1999, AmerenCIPS filed a notice with the ICC that it intends to transfer AmerenCIPS' generating facilities (all in Illinois) to a new nonregulated subsidiary of Ameren. The formation of the new generating subsidiary, as well as the transfer of AmerenCIPS' generating assets and liabilities (at historical net book value) and certain power sales contracts, is subject to various regulatory proceedings. Certain regulatory approvals were received from the ICC, the FERC, and the MoPSC. An additional PUHCA-related determination that will permit the new generating subsidiary to operate as an Exempt Wholesale Generator will be sought from the FERC. The generating subsidiary will include most of the new combustion turbine generators being acquired by Ameren, in addition to the AmerenCIPS facilities (see Note 2 – Regulatory Matters and Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). The new subsidiary is expected to be operational in mid-2000, subject to the outcome of these regulatory proceedings.

Once the transfer is completed, a power sales agreement would be in place between the new generating subsidiary and a nonregulated marketing affiliate for all generation. The marketing affiliate would have a power sales agreement with AmerenCIPS to supply it sufficient generation to meet native load requirements over the term of the agreement. Power will continue to be jointly dispatched between AmerenUE and the new generating subsidiary.

The proposed transfer of AmerenCIPS' generating assets and liabilities had no effect on the Company's financial statements as of December 31, 1999.

MISSOURI

In Missouri, where approximately 73% of the Company's retail electric revenues are derived, a task force appointed by the MoPSC investigated electric industry restructuring and competition. In 1998 the task force issued a report to the MoPSC that addressed many of the restructuring issues, but did not provide a specific recommendation or approach to restructure the industry. In addition, in 1998, the MoPSC staff issued a proposed plan for restructuring Missouri's electric industry. The staff's plan addressed a number of issues of concern if the industry is restructured in Missouri. It also included a proposal for less than full recovery of strandable costs. The staff's plan has not been addressed by the MoPSC. A joint committee of the Missouri legislature is also conducting hearings on these issues. Several restructuring bills were introduced by the Missouri legislature in 1999 and 2000. The Company is unable to predict the timing or ultimate outcome of electric industry restructuring in the state of Missouri.

SUMMARY

In summary, the potential negative consequences associated with electric industry restructuring could be significant and could include the impairment and writedown of certain assets, including generation-related plant and net regulatory assets, lower revenues, reduced profit margins and increased costs of capital and operations expenses. The Company is actively taking steps to mitigate these potential negative consequences. Most importantly, the Company will continue to focus on cost control to ensure that it maintains a competitive cost structure, which includes the recent termination of high-cost coal supply contracts (see Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). Also, in Illinois, the Company's actions include establishing a nonregulated generating subsidiary and expanding its generation assets, strengthening the Company's trading and marketing operations to maintain its current customers and obtain new customers, and enhancing its information systems. The Company believes that these actions will position the Company well in the competitive Illinois marketplace. In Missouri, the Company is actively involved in all major deliberations taking place surrounding electric industry restructuring in an effort to ensure that restructuring legislation, if any, contains an orderly transition and is equitable to the Company's shareholders. The Company is also actively involved in shaping the policies of the Midwest ISO to protect its shareholders' interests. At this time, the Company is unable to predict the ultimate impact of electric industry restructuring on the Company's future financial condition, results of operations or liquidity.

Year 2000 Issue

The Year 2000 Issue relates to how dates are stored and used in computer systems, applications, and embedded systems. As the century date change occurred, certain date-sensitive systems had to recognize the year as 2000 and not as 1900. This inability to recognize and properly treat the year as 2000 could have caused these systems to process critical financial and operational information incorrectly. Management implemented a Year 2000 plan and briefed Ameren's Board of Directors about the Year 2000 Issue and how it might have affected the Company. The Company encountered no significant problems associated with the Year

2000 Issue at year-end. In addressing the Year 2000 Issue, the Company incurred internal labor costs as well as external consulting and other expenses to prepare for the new century. As of December 31, 1999, the Company had expended approximately $8 million in external costs (consulting fees and related costs). The impact of the Year 2000 Issue on the Company's financial condition, results of operations or liquidity was immaterial. The Company will continue to monitor date-sensitive systems as certain key dates occur throughout the year.

Contingencies

See Note 2 – Regulatory Matters, Note 12 - Commitments and Contingencies and Note 13 – Callaway Nuclear Plant under Notes to Consolidated Financial Statements for material issues existing at December 31, 1999.

Market Risk Related to Financial Instruments and Commodity Instruments

Market risk represents the risk of changes in value of a financial instrument, derivative or non-derivative, caused by fluctuations in market variables (e.g., interest rates, equity prices, commodity prices, etc.). The following discussion of the Company's 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. The Company handles market risks in accordance with established policies, which may include entering into various derivative transactions. In the normal course of business, the Company also faces risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational, and credit risk and are not represented in the following analysis.

INTEREST RATE RISK

The Company is exposed to market risk through changes in interest rates through its issuance of both long-term and short-term variable-rate debt, fixed-rate debt, commercial paper and auction market preferred stock. The Company manages its interest rate exposure by controlling the amount of these instruments it holds within its total capitalization portfolio and by monitoring the effects of market changes in interest rates.

If interest rates increase 1% in 2000, as compared to 1999, the Company's interest expense would increase by approximately $9 million, and net income would decrease by approximately $5 million. This amount has been determined using the assumptions that the Company's outstanding variable-rate debt, commercial paper and auction market preferred stock, as of December 31, 1999, continued to be outstanding throughout 2000, and that the average interest rates for these instruments increased 1% over 1999. 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 its 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 the Company's financial structure.

COMMODITY PRICE RISK

The Company is exposed to changes in market prices for natural gas, fuel and electricity. With regard to its natural gas utility business, the Company's exposure to changing market prices is in large part mitigated by the fact that the Company has Purchased Gas Adjustment Clauses (PGAs) in place in both its Missouri and Illinois jurisdictions. The PGAs allow the Company to pass on to its customers its prudently incurred costs of natural gas. With approval of the MoPSC, AmerenUE participated in an experimental program to control the volatility of gas prices paid by its Missouri customers in the 1998-1999 winter months through the purchase of financial instruments. This program concluded in April 1999.

Since the Company does not have a provision similar to the PGA for its electric operations, the Company has entered into several long-term contracts with various suppliers to purchase coal and nuclear fuel to manage its exposure to fuel prices. (See Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). With regard to the Company's exposure to commodity price risk for purchased power and excess electricity sales, the Company has established a subsidiary, AmerenEnergy, whose primary responsibility includes managing market risks associated with changing market prices for electricity purchased and sold on behalf of the Company's operating subsidiaries, AmerenUE and AmerenCIPS.

AmerenEnergy utilizes several techniques to mitigate its market risk for electricity, 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 AmerenEnergy is allowed to utilize (which include forward contracts, futures contracts, and option contracts) are dictated by a risk management policy, which has been reviewed with the Auditing Committee of Ameren's Board of Directors. Compliance with the risk management policy is the responsibility of a risk management steering committee, consisting of Company officers and an independent risk management officer at AmerenEnergy.

As of December 31, 1999, the fair value of derivative financial instruments exposed to commodity price risk was immaterial. AmerenEnergy's primary use of derivatives has been limited to transactions that are either risk-neutral or that reduce price risk exposure of the Company.

EQUITY PRICE RISK

The Company maintains trust funds, as required by the Nuclear Regulatory Commission and Missouri and Illinois state laws, to fund certain costs of nuclear decommissioning (see Note 13 – Callaway Nuclear Plant under Notes to Consolidated Financial Statements for further information). As of December 31, 1999, these funds were invested primarily in domestic equity securities, fixed-rate, fixed-income securities, and cash and cash equivalents. By maintaining a portfolio that includes long-term equity investments, the Company is seeking to maximize the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in the Company's portfolio are exposed to price fluctuations in equity markets, and the fixed-rate, fixed-income securities are exposed to changes in interest rates. The Company actively monitors its portfolio by benchmarking the performance of its investments against certain indices and by maintaining, and periodically reviewing, established target allocation percentages of the assets of its trusts to various investment options. The Company's exposure to equity price market risk is in large part mitigated due to the fact that the Company is currently allowed to recover its decommissioning costs in its rates.

Accounting Matters

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities and requires recognition of all derivatives as either assets or liabilities on the balance sheet measured at fair value. The intended use of the derivatives and their designation as either a fair value hedge, a cash flow hedge, or a foreign currency hedge will determine when the gains or losses on the derivatives are to be reported in earnings and when they are to be reported as a component of other comprehensive income. In June 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No. 133," which delayed the effective date of SFAS 133 to all fiscal quarters of all fiscal years, beginning after June 15, 2000. Earlier application is still encouraged. The Company expects to adopt SFAS 133 in the first quarter of 2001.

The Company is currently evaluating the impact of SFAS 133 on its financial position and results of operations upon adoption. The Company's evaluation includes reviewing existing derivative instruments and contracts to determine the appropriate accounting for these items under SFAS 133. At this time, management believes that adoption of SFAS 133 will not have a material impact on the Company's financial position or results of operations upon adoption based on the derivative instruments which existed as of December 31, 1999. However, changing market conditions, the volume of future transactions which may fall within the scope of SFAS 133, and potential amendments to SFAS 133 could change management's current assessment. As a result, SFAS 133 could increase the volatility of the Company's future earnings and could be material to the Company's financial position and results of operations upon adoption.

Effects of Inflation and Changing Prices

The Company's rates for retail electric and gas utility service are generally regulated by the MoPSC and the ICC. Non-retail electric rates are regulated by the FERC.

The current replacement cost of the Company's utility plant substantially exceeds its 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 plants in future years. Regulatory practice has been modified for the Company's generation portion of its business in its Illinois jurisdiction and may be modified in the future for the Company's Missouri jurisdiction (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). In addition, the impact on common stockholders is mitigated to the extent depreciable property is financed with debt that is repaid with dollars of less purchasing power.

In the Illinois retail jurisdiction, the cost of fuel for electric generation, which was previously reflected in billings to customers through Uniform Fuel Adjustment Clauses, has been added to base rates as provided for in the Illinois Law (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). In the Missouri retail jurisdiction, the cost of fuel for electric generation is reflected in base rates with no provision for changes to be made through a fuel adjustment clause. In Illinois and Missouri, changes in gas costs are generally reflected in billings to customers through Purchased Gas Adjustment Clauses.

Inflation continues to be a factor affecting operations, earnings, stockholders' equity and financial performance.

Safe Harbor Statement

Statements made in this annual report to stockholders 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, financial performance and the Year 2000 Issue. In connection with the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995, the Company is 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 regulatory actions; changes in laws and other governmental actions; the impact on the Company of current regulations related to the phasing-in of the opportunity for some 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 the Company's business at both the state and Federal levels; future market prices for fuel and purchased power, electricity, and natural gas, including the use of financial instruments; average rates for electricity in the Midwest; business and economic conditions; interest rates; weather conditions; fuel prices and availability; generation plant performance; 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; monetary and fiscal policies; future wages and employee benefits costs; and legal and administrative proceedings.

Consolidated Statement of Income

Thousands of Dollars, Except Share and Per Share Amounts *Year Ended December 31,*	*1999*	*1998*	*1997*
Operating Revenues:			
Electric	$3,287,590	$3,094,211	$3,064,177
Gas	228,298	216,681	249,815
Other	7,743	7,316	12,551
Total Operating Revenues	3,523,631	3,318,208	3,326,543
Operating Expenses:			
Operations			
Fuel and purchased power	973,277	780,123	836,445
Gas	131,449	118,846	160,679
Other	629,482	647,157	585,214
	1,734,208	1,546,126	1,582,338
Maintenance	370,873	312,011	310,241
Depreciation and amortization	350,539	348,403	346,000
Income taxes	258,870	267,673	234,179
Other taxes	246,592	272,774	271,711
Total Operating Expenses	2,961,082	2,746,987	2,744,469
Operating Income	562,549	571,221	582,074
Other Income and (Deductions):			
Allowance for equity funds used during construction	7,161	5,001	5,244
Miscellaneous, net	(10,813)	(2,609)	(10,344)
Total Other Income and (Deductions)	(3,652)	2,392	(5,100)
Income Before Interest Charges and Preferred Dividends	558,897	573,613	576,974
Interest Charges and Preferred Dividends:			
Interest	168,275	181,580	185,368
Allowance for borrowed funds used during construction	(7,123)	(7,026)	(7,462)
Preferred dividends of subsidiaries	12,650	12,562	12,532
Net Interest Charges and Preferred Dividends	173,802	187,116	190,438
Income Before Extraordinary Charge	385,095	386,497	386,536
Extraordinary Charge, Net of Income Taxes (Note 2)	-	-	(51,820)
NET INCOME	$ 385,095	$ 386,497	$ 334,716
Earnings per Common Share – Basic and Diluted (based on average shares outstanding)			
Income before extraordinary charge	$2.81	$2.82	$2.82
Extraordinary charge	-	-	(.38)
Net Income	$2.81	$2.82	$2.44
AVERAGE COMMON SHARES OUTSTANDING	137,215,462	137,215,462	137,215,462

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

Thousands of Dollars December 31,	1999	1998
Assets		
Property and Plant, at Original Cost:		
Electric	$12,053,411	$11,761,306
Gas	491,708	469,216
Other	92,696	44,646
	12,637,815	12,275,168
Less accumulated depreciation and amortization	5,891,340	5,602,816
	6,746,475	6,672,352
Construction work in progress:		
Nuclear fuel in process	88,830	108,294
Other	329,880	147,393
Total Property and Plant, Net	7,165,185	6,928,039
Investments and Other Assets:		
Investments	66,476	86,694
Nuclear decommissioning trust fund	186,760	161,877
Other	80,737	78,091
Total Investments and Other Assets	333,973	326,662
Current Assets:		
Cash and cash equivalents	194,882	76,863
Accounts receivable – trade (less allowance for doubtful accounts of $7,136 and $8,393, respectively)	216,344	198,193
Unbilled revenue	154,097	150,481
Other accounts and notes receivable	20,668	76,919
Materials and supplies, at average cost:		
Fossil fuel	123,143	112,908
Other	130,081	132,884
Other	39,791	22,912
Total Current Assets	879,006	771,160
Regulatory Assets:		
Deferred income taxes	622,520	633,529
Other	176,931	188,049
Total Regulatory Assets	799,451	821,578
TOTAL ASSETS	$ 9,177,615	$ 8,847,439

See Notes to Consolidated Financial Statements.

Thousands of Dollars, Except Share and Per Share Amounts	*December 31,*	*1999*	*1998*
Capital and Liabilities			
Capitalization:			
Common stock, $.01 par value, 400,000,000 shares authorized - 137,215,462 shares outstanding (Note 6)		$ 1,372	$ 1,372
Other paid-in capital, principally premium on common stock		1,582,501	1,582,548
Retained earnings (see accompanying statement)		1,505,827	1,472,200
Total Common Stockholders' Equity		3,089,700	3,056,120
Preferred stock not subject to mandatory redemption (Note 6)		235,197	235,197
Long-term debt (Note 8)		2,448,448	2,289,424
Total Capitalization		5,773,345	5,580,741
Minority Interest in Consolidated Subsidiaries		4,010	3,534
Current Liabilities:			
Current maturity of long-term debt (Note 8)		128,867	201,713
Short-term debt		80,165	58,528
Accounts and wages payable		341,274	284,818
Accumulated deferred income taxes		70,719	66,299
Taxes accrued		155,396	114,106
Other		300,747	216,889
Total Current Liabilities		1,077,168	942,353
Commitments and Contingencies (Notes 2, 12 and 13)			
Accumulated deferred income taxes		1,493,634	1,521,417
Accumulated deferred investment tax credits		170,834	178,832
Regulatory liability		188,404	198,937
Other deferred credits and liabilities		470,220	421,625
TOTAL CAPITAL AND LIABILITIES		$9,177,615	$8,847,439

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Thousands of Dollars — *Year Ended December 31,*	*1999*	*1998*	*1997*
Cash Flows From Operating:			
Income before extraordinary charge	$385,095	$386,497	$386,536
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	340,329	338,488	340,079
Amortization of nuclear fuel	36,068	36,855	37,126
Allowance for funds used during construction	(14,284)	(12,027)	(12,706)
Deferred income taxes, net	(22,578)	(24,849)	(24,499)
Deferred investment tax credits, net	(7,998)	(11,428)	(18,967)
Changes in assets and liabilities:			
Receivables, net	34,484	(6,658)	11,476
Materials and supplies	(7,432)	(18,209)	16,523
Accounts and wages payable	56,456	(8,573)	(3,626)
Taxes accrued	41,290	3,540	45,321
Other	76,145	119,608	(68,820)
Net Cash Provided by Operating Activities	917,575	803,244	708,443
Cash Flows From Investing:			
Construction expenditures	(570,807)	(324,905)	(380,593)
Allowance for funds used during construction	14,284	12,027	12,706
Nuclear fuel expenditures	(21,901)	(20,432)	(35,432)
Other	20,218	10,494	16,122
Net Cash Used in Investing Activities	(558,206)	(322,816)	(387,197)
Cash Flows From Financing:			
Dividends on common stock	(348,527)	(348,527)	(331,282)
Redemptions:			
Nuclear fuel lease	(15,138)	(67,720)	(28,292)
Short-term debt	-	(27,738)	-
Long-term debt	(174,444)	(273,444)	(123,444)
Preferred stock	-	-	(63,924)
Issuances:			
Nuclear fuel lease	64,972	16,439	40,337
Short-term debt	21,637	-	17,198
Long-term debt	210,150	255,000	187,000
Net Cash Used in Financing Activities	(241,350)	(445,990)	(302,407)
Net Change in Cash and Cash Equivalents	118,019	34,438	18,839
Cash and Cash Equivalents at Beginning of Year	76,863	42,425	23,586
CASH AND CASH EQUIVALENTS AT END OF YEAR	$194,882	$ 76,863	$ 42,425
Cash paid during the periods:			
Interest (net of amount capitalized)	$162,705	$175,168	$162,459
Income taxes	$247,428	$298,589	$249,477

SUPPLEMENTAL DISCLOSURE OF NONCASH TRANSACTION

An extraordinary charge to earnings was recorded in the fourth quarter of 1997 for the write-off of generation-related regulatory assets and liabilities of the Company's Illinois retail electric business as a result of electric industry restructuring legislation enacted in Illinois in December 1997. The write-off reduced earnings $52 million, net of income taxes. See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

See Notes to Consolidated Financial Statements.

Consolidated Statement of Retained Earnings

Thousands of Dollars *Year Ended December 31,*	*1999*	*1998*	*1997*
Balance at Beginning of Period	$1,472,200	$1,434,658	$1,431,295
Add:			
Net income	385,095	386,497	334,716
Deduct:			
Dividends	351,468	348,955	331,353
Balance at Close of Period	$1,505,827	$1,472,200	$1,434,658

Selected Quarterly Information

(Unaudited)

Thousands of Dollars, Except Per Share Amounts

Quarter Ended	Operating Revenues	Operating Income	Net Income (Loss)	Earnings (Loss) Per Common Share
March 31, 1999 (a)	$ 735,902	$ 99,687	$ 54,359	$ .40
March 31, 1998 (a)	700,810	90,432	39,927	.29
June 30, 1999	859,884	130,512	86,519	.63
June 30, 1998 (b)	821,777	128,158	83,632	.61
September 30, 1999	1,193,462	296,727	249,819	1.82
September 30, 1998 (c)	1,117,118	283,652	236,657	1.73
December 31, 1999 (d)	734,383	35,623	(5,602)	(.04)
December 31, 1998	678,503	68,979	26,281	.19

(a) The first quarter of 1999 and 1998 included credits to Missouri electric customers that reduced net income approximately $11 million, or 8 cents per share, and $6 million, or 4 cents per share, respectively.

(b) The second quarter of 1998 included credits to Missouri electric customers that reduced net income approximately $18 million, or 14 cents per share. Callaway Plant refueling expenses, which decreased net income approximately $18 million, or 13 cents per share, were also included in the second quarter of 1998.

(c) The third quarter of 1998 included a nonrecurring charge related to the targeted employee separation plan that reduced net income $15 million, or 11 cents per share. (See Note 3 – Targeted Separation Plan under Notes to Consolidated Financial Statements for further information).

(d) The fourth quarter of 1999 included adjustments that increased earnings $9 million, or 6 cents per share, as a result of a Report and Order received from the Missouri Public Service Commission relating to the Company's alternative regulation plan. (See Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). The fourth quarter of 1999 also included a charge of $31 million, or 23 cents per share, for coal supply contract terminations. (See Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). In addition, Callaway Plant refueling expenses, which decreased net income approximately $22 million, or 16 cents per share, were included in the fourth quarter of 1999.

Other changes in quarterly earnings are due to the effect of weather on sales and other factors that are characteristic of public utility operations.

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

NOTE 1

Summary of Significant Accounting Policies

BASIS OF PRESENTATION

Ameren Corporation (Ameren) is a holding company registered under the Public Utility Holding Company Act of 1935 (PUHCA). In December 1997, Union Electric Company (AmerenUE) and CIPSCO Incorporated (CIPSCO) combined to form Ameren, with AmerenUE and CIPSCO's subsidiaries, Central Illinois Public Service Company (AmerenCIPS) and CIPSCO Investment Company (CIC), becoming subsidiaries of Ameren (the Merger). The accompanying consolidated financial statements (the financial statements) reflect the accounting for the Merger as a pooling of interests and are presented as if the companies were combined as of the earliest period presented. However, the financial information is not necessarily indicative of the results of operations, financial position or cash flows that would have occurred had the Merger been consummated for the periods for which it is given effect, nor is it necessarily indicative of future results of operations, financial position or cash flows. The outstanding preferred shares of AmerenUE and AmerenCIPS were not affected by the Merger.

The accompanying financial statements include the accounts of Ameren and its consolidated subsidiaries (collectively the Company). All subsidiaries for which the Company owns directly or indirectly more than 50% of the voting stock are included as consolidated subsidiaries. Ameren's primary operating companies, AmerenUE and AmerenCIPS, are engaged principally in the generation, transmission, distribution and sale of electric energy and the purchase, distribution, transportation and sale of natural gas. The operating companies serve 1.5 million electric and 300,000 natural gas customers in a 44,500-square-mile area of Missouri and Illinois. The Company's nonregulated subsidiaries include CIC, an investing subsidiary; AmerenEnergy, Inc., an energy marketing subsidiary; Ameren Development Company, a nonregulated products and services subsidiary; Ameren Intermediate Holding Company, a holding company for the proposed Illinois nonregulated generating subsidiary and its proposed marketing affiliate (see Note 2 – Regulatory Matters for further information); and Ameren Services Company, a shared support services subsidiary. The Company also has a 60% interest in Electric Energy, Inc. (EEI). EEI owns and operates an electric generation and transmission facility in Illinois that supplies electric power primarily to a uranium enrichment plant located in Paducah, Kentucky. All significant intercompany balances and transactions have been eliminated from the consolidated financial statements.

REGULATION

Ameren is subject to regulation by the Securities and Exchange Commission (SEC). AmerenUE is also regulated by the Missouri Public Service Commission (MoPSC), Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). AmerenCIPS is also regulated by the ICC and the FERC. The accounting policies of the Company conform to U.S. generally accepted accounting principles (GAAP). See Note 2 - Regulatory Matters for further information.

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 the Company's regulated assets, and interest during construction is added for nonregulated assets. Maintenance expenditures and the renewal of items not considered units of property are charged to income, as incurred. When units of depreciable property are retired, the original cost and removal cost, less salvage value, are charged to accumulated depreciation.

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 1999, 1998 and 1997 was approximately 3% of the average depreciable cost.

FUEL AND GAS COSTS

In the Missouri and Illinois retail electric jurisdictions, the cost of fuel for electric generation is reflected in base rates with no provision for changes to be made through fuel adjustment clauses. (See Note 2 - Regulatory Matters for further information.) In the Illinois jurisdiction in 1997, changes in fuel costs were generally reflected in billings to electric customers through fuel adjustment clauses. In the Illinois and Missouri retail gas jurisdictions, changes in gas costs are generally reflected in billings to gas customers through purchased gas adjustment clauses.

NUCLEAR FUEL

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.

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.

INCOME TAXES

The Company and its subsidiaries 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.

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 the Company's regulated construction program 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% - 10% during 1999, 6% - 9% during 1998, and 8% - 9% during 1997.

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

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

ENERGY CONTRACTS

The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) Issue 98-10, "Accounting for Energy Trading and Risk Management Activities" became effective on January 1, 1999. EITF 98-10 provides guidance on the accounting for energy contracts entered into for the purchase or sale of electricity, natural gas, capacity and transportation. The EITF reached a consensus in EITF 98-10 that sales and purchase activities being performed need to be classified as either trading or nontrading. Furthermore, transactions that are determined to be trading activities would be recognized on the balance sheet measured at fair value, with gains and losses included in earnings. AmerenEnergy, Inc., an energy marketing subsidiary of Ameren, enters into contracts for the sale and purchase of energy on behalf of AmerenUE and AmerenCIPS. Currently, virtually all of AmerenEnergy's transactions are considered nontrading activities and are accounted for using the accrual or settlement method, which represents industry practice. EITF 98-10 did not have a material impact on the Company's financial position or results of operations upon adoption.

SOFTWARE

Statement of Position (SOP) 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use" became effective on January 1, 1999. SOP 98-1 provides guidance on accounting for the costs of computer software developed or obtained for internal use. Under SOP 98-1, certain costs may be capitalized and amortized over some future period. SOP 98-1 did not have a material impact on the Company's financial position or results of operations upon adoption.

EVALUATION OF ASSETS FOR IMPAIRMENT

Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" prescribes general standards for the recognition and measurement of impairment losses. The Company determines if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount. An impairment loss is recognized if the undiscounted expected future cash flows are less than the carrying amount of the asset. SFAS 121 also requires that regulatory assets which are no longer probable of recovery through future revenues be charged to earnings (see Note 2 - Regulatory Matters for further information). As of December 31, 1999, no impairment was identified.

STOCK COMPENSATION PLANS

The Company applies Accounting Principles Board Opinion (APB) 25, "Accounting for Stock Issued to Employees" in accounting for its plans. See Note 11 - Stock Option Plans for further information.

EARNINGS PER SHARE

The Company's calculation of basic and diluted earnings per share resulted in the same earnings per share amounts for each of the years 1999, 1998 and 1997. The reconciling item in each of the years is comprised of assumed stock option conversions which increased the number of shares outstanding in the diluted earnings per share calculation by 38,786 shares, 29,787 shares and 7,318 shares in 1999, 1998 and 1997, respectively.

USE OF ESTIMATES

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.

RECLASSIFICATIONS

Certain reclassifications have been made to prior-years' financial statements to conform with 1999 reporting.

NOTE 2
Regulatory Matters

MISSOURI ELECTRIC

In July 1995, the MoPSC approved an agreement establishing contractual obligations involving the Company's Missouri retail electric rates. Included was a three-year experimental alternative regulation plan (the Original Plan) that ran from July 1, 1995, through June 30, 1998, which provided that earnings in those years in excess of a 12.61% regulatory return on equity (ROE) be shared equally between customers and stockholders, and earnings above a 14% ROE be credited to customers. The formula for computing the credit used twelve-month results ending June 30, rather than calendar year earnings. In 1996, the Company recorded a $47 million credit for the first year of the Original Plan. This credit reduced earnings $28 million, or 20 cents per share. During 1997, the Company recorded a $20 million credit for the second year of the Original Plan, which reduced earnings $11 million, or 8 cents per share. In 1998, the Company recorded an estimated $43 million credit for the final year of the Original Plan, which reduced earnings $26 million, or 18 cents per share.

Included in the joint agreement approved by the MoPSC in its February 1997 order authorizing the Merger, was a new three-year experimental alternative regulation plan (the New Plan) that runs from July 1, 1998, through June 30, 2001. Like the Original Plan, the New Plan requires that earnings over a 12.61% ROE up to a 14% ROE be shared equally between customers and shareholders. The New Plan also returns to customers 90% of all earnings above a 14% ROE up to a 16% ROE. Earnings above a 16% ROE are credited entirely to customers. In addition, the joint agreement provides for a Missouri electric rate decrease, retroactive to September 1, 1998, based on the weather-adjusted average annual credits to customers under the Original Plan. The Company estimated that its Missouri electric rate decrease should approximate $20 million on an annualized basis and reduced revenues accordingly since September 1998.

In November 1998, the MoPSC staff proposed adjustments to the customer credit for the third year of the Original Plan. In addition, the MoPSC staff proposed adjustments to the Company's estimated Missouri electric rate decrease based upon their methodology of calculating the weather-adjusted credits. The determination of the credit for the third year of the Original Plan, as well as the determination of the Missouri electric rate decrease, were subject to regulatory proceedings before the MoPSC in 1999.

On December 23, 1999, the MoPSC issued a Report and Order (Order) related to the customer credit for the third year of the Original Plan. Certain of the MoPSC staff's proposed adjustments were accepted by the MoPSC in the Order. In addition, the Order requires the Company to capitalize and amortize certain costs (including computer software costs) that had previously been expensed for its Missouri electric operations.

Based on the provisions of the Order, the Company estimates that the credit for the third year of the Original Plan will approximate $31 million. In addition, with regard to the Missouri electric rate decrease, the Company, the MoPSC staff, and other parties reached a settlement related to the calculation of the weather-adjusted credits. As a result, the Company estimates that the annualized Missouri electric rate decrease will approximate $17 million. Both of these estimates are subject to final approval of the MoPSC.

The provisions of the Order also have an impact on the estimated credit to electric customers recorded by the Company for the first year of the New Plan. As a result, the Company recorded an estimated credit of $25 million for the plan year ended June 30, 1999. In addition, the Company recorded an estimated $20 million credit for the 1999 portion of the second year of the New Plan. Also, the provision of the Order which requires the Company to capitalize and amortize certain costs (including computer software costs) that had been previously expensed resulted in the capitalization of approximately $20 million of costs in the fourth quarter of 1999.

In summary, the provisions of the Order and the resulting changes in the Company's estimates of credits and Missouri electric rate decrease for the open years under the Original Plan and the New Plan resulted in an increase in earnings of approximately $9 million, or 6 cents per share in the fourth quarter of 1999.

On December 30, 1999, the Company filed a request for rehearing with the MoPSC, asking that it reconsider its decision to adopt certain of the MoPSC staff's adjustments. On January 25, 2000, the MoPSC denied the Company's request. The Company plans to file an appeal with the courts.

GAS

In February 1999, the ICC approved a $9 million total annual rate increase for natural gas service in AmerenUE's and AmerenCIPS' Illinois jurisdictions. The increase became effective in February 1999.

In December 1997, the MoPSC approved a $12 million annual rate increase for natural gas service in AmerenUE's Missouri jurisdiction. The rate increase became effective in February 1998.

MIDWEST ISO

In 1998, Ameren's operating subsidiaries joined a group of companies that support the formation of the Midwest Independent System Operator (Midwest ISO). An ISO operates, but does not own, electric transmission systems and maintains system reliability and security while alleviating pricing issues associated with the "pancaking" of rates. The Midwest ISO would be regulated by the FERC. Thirteen transmission-owning utilities have joined the Midwest ISO, as of December 31, 1999. The FERC conditionally approved the formation of the Midwest ISO in September 1998, and it is expected to be operational during the year 2001. The MoPSC and the ICC have authorized AmerenUE and AmerenCIPS to join the Midwest ISO and to transfer control of their transmission facilities to the Midwest ISO. The Midwest ISO covers 14 states, represents portions of 60,000 miles of transmission line and controls $8 billion in assets. The Company believes that the operation of the Midwest ISO will not have a material adverse effect on its financial condition, results of operations or liquidity.

In December 1999, the FERC issued its Order 2000 relating to Regional Transmission Organizations (RTOs) that would meet certain characteristics such as size and independence. Order 2000 calls on all transmission owners to join RTOs. In particular, all public utilities that own, operate, or control interstate transmission facilities must file with the FERC by October 15, 2000, a proposal for an RTO, or alternatively a description of efforts by the utility to join an RTO. The Company expects that its participation in the Midwest ISO will satisfy the requirements of Order 2000.

ILLINOIS ELECTRIC RESTRUCTURING

Certain states are considering proposals or have adopted legislation that will promote competition at the retail level. In December 1997, the Governor of Illinois signed the Electric Service Customer Choice and Rate Relief Law of 1997 (the Illinois Law) providing for electric utility restructuring in Illinois. This legislation introduces competition into the supply of electric energy at retail in Illinois.

Under the Illinois Law, retail direct access, which allows customers to choose their electric generation suppliers, will be phased in over several years. Access for commercial and industrial customers will occur over a period from October 1999 to December 2000, and access for residential customers will occur after May 1, 2002.

As a requirement of the Illinois Law, in March 1999, AmerenUE and AmerenCIPS filed delivery service tariffs with the ICC. These tariffs would be used by electric customers who choose to purchase their power from alternate suppliers. On August 25, 1999, the ICC issued an order approving the delivery services tariffs, with an allowed rate of return on equity of 10.45%. AmerenUE and AmerenCIPS filed a joint petition for rehearing of that order requesting the ICC to alter its conclusions on a number of issues. On October 13, 1999, the ICC granted a rehearing on certain issues. An order on this reopened proceeding is expected in early 2000.

The Illinois Law included a 5% residential electric rate decrease for the Company's Illinois electric customers, effective August 1, 1998. This rate decrease reduced electric revenues approximately $8 million in 1999. The Company may be subject to additional 5% residential electric rate decreases in each of 2000 and 2002, to the extent its rates exceed the Midwest utility average at that time. The Company's rates are currently below the Midwest utility average.

As a result of the Illinois Law, AmerenUE and AmerenCIPS filed proposals with the ICC to eliminate their electric fuel adjustment clauses for Illinois retail customers, thereby including historical levels of fuel costs in base rates. The ICC approved AmerenUE's and AmerenCIPS' filings in early 1998.

The Illinois Law also contains a provision requiring that one-half of excess earnings from the Illinois jurisdiction for the years 1998 through 2004 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 US Treasury bonds, plus prescribed percentages ranging from 4% to 7%. Filings must be made with the ICC on, or before, March 31 of each year 2000 through 2005. As of December 31, 1999, the Company recorded an estimated $5 million credit it expects to return to its customers under the Illinois Law for the two-year period ended December 31, 1999.

In conjunction with another provision of the Illinois Law, in July 1999, AmerenCIPS filed a notice with the ICC that it intends to transfer AmerenCIPS' generating facilities (all in Illinois) to a new nonregulated subsidiary of Ameren. The formation of the new generating subsidiary, as well as the transfer of AmerenCIPS' generating assets and liabilities (at historical net book value) and certain power sales contracts, are subject to various regulatory proceedings. Certain regulatory approvals were received from the ICC, the FERC, and the MoPSC. An additional PUHCA-related determination that will permit the new generating subsidiary to operate as an Exempt Wholesale Generator will be sought from the FERC. The generating subsidiary will include most of the new combustion turbine generators being acquired by Ameren in addition to the AmerenCIPS facilities. (See Note 12 – Commitments and Contingencies for further information.) The new generating subsidiary is expected to be operational in mid-2000, subject to the outcome of these regulatory proceedings. The proposed transfer of AmerenCIPS' generating assets and liabilities had no effect on Ameren's financial statements as of December 31, 1999.

Once the transfer is completed, a power sales agreement would be in place between the new generating subsidiary and a nonregulated marketing affiliate for all generation. The marketing affiliate would have a power sales agreement with AmerenCIPS to supply it sufficient generation to meet native load requirements over the term of the agreement. Power will continue to be jointly dispatched between AmerenUE and the new generating subsidiary.

Other provisions of the Illinois Law include (1) potential recovery of a portion of strandable costs, which represent costs which would not be recoverable in a restructured environment, through a transition charge collected from customers who choose another electric supplier; (2) a mechanism to securitize certain future revenues; and (3) a provision relieving the Company of the requirement to file electric rate cases or alternative regulatory plans in Illinois, following the consummation of the Merger to reflect the effects of net merger savings.

The Company's accounting policies and financial statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Such effects concern mainly the time at which various items enter into the determination of net income in order to follow the principle of matching costs and revenues. For example, SFAS 71 allows the Company to record certain assets and liabilities (regulatory assets and regulatory liabilities) that are expected to be recovered or settled in future rates and would not be recorded under GAAP for nonregulated entities. In addition, reporting under SFAS 71 allows companies whose service obligations and prices are regulated to maintain assets on their balance sheets representing costs they reasonably expect to recover from customers, through inclusion of such costs in future rates. SFAS 101, "Accounting for the Discontinuance of Application of FASB Statement No. 71," specifies how an enterprise that ceases to meet the criteria for application of SFAS 71 for all or part of its operations should report that event in its financial statements. In general, SFAS 101 requires that the enterprise report the discontinuance of SFAS 71 by eliminating from its balance sheet all regulatory assets and liabilities related to the portion of the business that no longer meets the SFAS 71 criteria. The EITF has concluded that application of SFAS 71 accounting should be discontinued once sufficiently detailed deregulation legislation is issued for a separable portion of a business for which a plan of deregulation has been established. However, the EITF further concluded that regulatory assets associated with the deregulated portion of the business, which will be recovered through tariffs charged to customers of a regulated portion of the business, should be associated with the regulated portion of the business from which future cash recovery is expected (not the portion of the business from which the costs originated). Those assets can therefore continue to be carried on the regulated entity's balance sheet to the extent such assets are recoverable. In addition, SFAS 121 establishes accounting standards for the impairment of long-lived assets.

Due to the enactment of the Illinois Law, prices for the retail supply of electric generation are expected to transition from cost-based, regulated rates to rates determined in large part by competitive market forces in the state of Illinois. As a result, the Company discontinued application of SFAS 71 for the Illinois retail portion of its generating business (i.e., the portion of the Company's business related to the supply of electric energy in Illinois) in the fourth quarter of 1997. The Company evaluated the impact of the Illinois Law on the future recoverability of its regulatory assets and liabilities related to the generation portion of its business and determined that it was not probable that such assets and liabilities would be recovered through the cash flows from the regulated portion of its business. Accordingly, the Company's generation-related regulatory assets and liabilities of its Illinois retail electric business were written off in the fourth quarter of 1997, resulting in an extraordinary charge to earnings of $52 million, net of income taxes, or 38 cents per share. These regulatory assets and liabilities included previously incurred costs originally expected to be collected/refunded in future revenues, such as coal contract restructuring costs, deferred charges related to a generating plant, costs associated with an abandoned scrubber at a generating plant, and income tax-related regulatory assets and liabilities. In addition, the Company has evaluated whether the recoverability of the costs associated with its remaining net generation-related assets has been impaired as defined under SFAS 121. The Company has concluded that impairment, as defined under SFAS 121, does not exist and that no plant writedowns are necessary at this time. At December 31, 1999, the Company's net investment in generation facilities related to its Illinois retail jurisdiction approximated $861 million and was included in electric plant in-service on the Company's consolidated balance sheet.

In August 1999, the Company filed a transmission system rate case with the FERC. This filing was primarily designed to implement rates, terms and conditions for transmission service for those retail customers in Illinois who choose other suppliers as allowed under the Illinois Law. On October 14, 1999, the FERC issued an order suspending the proposed rates until March 25, 2000. In January 2000, a settlement in principle was reached with the FERC trial staff and other interested parties. The settlement establishes the rates for transmission service that are to go into effect in the first quarter of 2000. The settlement is subject to approval by the FERC. The Company expects that the FERC will approve the settlement in 2000.

The provisions of the Illinois Law could also result in lower revenues, reduced profit margins and increased costs of capital and operations expense. At this time, the Company is unable to determine the impact of the Illinois Law on the Company's future financial condition, results of operations or liquidity.

MISSOURI ELECTRIC RESTRUCTURING

In Missouri, where approximately 73% of the Company's retail electric revenues are derived, a task force appointed by the MoPSC investigated electric industry restructuring and competition. In 1998, the task force issued a report to the MoPSC that addressed many of the restructuring issues but did not provide a specific recommendation or approach to restructure the industry. In addition, in 1998, the MoPSC staff issued a proposed plan for restructuring Missouri's electric industry. The staff's plan addressed a number of issues of concern if the industry is restructured in Missouri. It also included a proposal for less than full recovery of strandable costs. The staff's plan has not been addressed by the MoPSC. A joint committee of the Missouri legislature is also conducting hearings on these issues. Several restructuring bills were introduced by the Missouri legislature in 1999 and 2000.

The Company is unable to predict the timing or ultimate outcome of electric industry restructuring in the state of Missouri, as well as the impact of potential electric industry restructuring matters on the Company's future financial condition, results of operations or liquidity. The potential negative consequences of electric industry restructuring could be significant and include the impairment and write-down of certain assets, including generation-related plant and net regulatory assets, lower revenues, reduced profit margins and increased costs of capital and operations expense. At December 31, 1999, the Company's net investment in generation facilities related to its Missouri jurisdiction approximated $2.6 billion and was included in electric plant in-service on the Company's balance sheet. In addition, at December 31, 1999, the Company's Missouri net generation-related regulatory assets approximated $454 million.

REGULATORY ASSETS AND LIABILITIES

In accordance with SFAS 71, the Company has deferred certain costs pursuant to actions of its regulators, and is currently recovering such costs in electric rates charged to customers.

At December 31, the Company had recorded the following regulatory assets and regulatory liability:

In Millions	*1999*	*1998*
Regulatory Assets:		
Income taxes	$623	$634
Callaway costs	92	95
Unamortized loss on reacquired debt	31	33
Merger costs	27	24
Other	26	36
Regulatory Assets	$799	$822
Regulatory Liability:		
Income taxes	$188	$199
Regulatory Liability	$188	$199

Income Taxes: See Note 9 - Income Taxes.
Callaway Costs: 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 (through 2024).
Unamortized Loss on Reacquired Debt: 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.
Merger Costs: Represents the portion of merger-related expenses applicable to the Missouri retail jurisdiction. These costs are being amortized within 10 years, based on a MoPSC order.

The Company continually assesses the recoverability of its 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. However, as noted in the above paragraphs, electric industry restructuring legislation may impact the recoverability of regulatory assets in the future.

NOTE 3
Targeted Separation Plan

In July 1998, the Company offered separation packages to employees whose positions were eliminated through a targeted separation plan (TSP). During the third quarter of 1998, a nonrecurring, pretax charge of $25 million was recorded, reducing earnings $15 million, or 11 cents per share. This represented costs incurred to implement the TSP.

NOTE 4
Concentration of Risk

MARKET RISK

The Company engages in price risk management activities related to electricity and fuel. In addition to buying and selling these commodities, the Company uses derivative financial instruments to manage market risks and reduce exposure resulting from fluctuations in interest rates and the prices of electricity and fuel. Derivative instruments used include futures, forward contracts and options. The use of these types of contracts allows the Company to manage and hedge its contractual commitments and reduce exposure related to the volatility of commodity market prices.

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 guaranteed by NYMEX and have nominal credit risk. On all other transactions, the Company is exposed to credit risk in the event of nonperformance by the counterparties in the transaction.

The Company's financial instruments subject to credit risk consist primarily of trade accounts receivables and forward contracts. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising the Company's customer base. The Company's revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. For each counterparty in forward contracts, the Company analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis through a credit risk management program.

NOTE 5
Nuclear Fuel Lease

The Company has a lease agreement that provides for the financing of nuclear fuel. At December 31, 1999, the maximum amount that could be financed under the agreement was $120 million. Pursuant to the terms of the lease, the Company has assigned 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.

The Company is obligated to reimburse the lessor for all expenditures for nuclear fuel, interest and related costs. Obligations under this lease become due as the nuclear fuel is consumed at the Company's Callaway Nuclear Plant. The Company reimbursed the lessor $16 million in 1999, $23 million during 1998 and $31 million during 1997.

The Company has capitalized the cost, including certain interest costs, of the leased nuclear fuel and has recorded the related lease obligation. Total interest charges under the lease were $5 million in 1999 and 1998 and $6 million in 1997. Interest charges for these years were based on average interest rates of approximately 6%. Interest charges of $4 million were capitalized in 1999 and $3 million were capitalized in 1998 and 1997.

NOTE 6
Shareholder Rights Plan and Preferred Stock of Subsidiaries

In October 1998, the Company's 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 Ameren is acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of the Company's 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.

At December 31, 1999 and 1998, AmerenUE and AmerenCIPS had 25 million shares and 4.6 million shares respectively, of authorized preferred stock.

Outstanding preferred stock is entitled to cumulative dividends and is redeemable at the prices shown in the following table:

Preferred Stock Outstanding Not Subject to Mandatory Redemption:

Dollars In Millions	*Redemption Price (per share)*	*December 31, 1999*	*1998*
Without par value and stated value of $100 per share —			
$7.64 Series - 330,000 shares	$103.82 – note (a)	$ 33	$ 33
$5.50 Series A - 14,000 shares	110.00	1	1
$4.75 Series - 20,000 shares	102.176	2	2
$4.56 Series - 200,000 shares	102.47	20	20
$4.50 Series - 213,595 shares	110.00 – note (b)	21	21
$4.30 Series - 40,000 shares	105.00	4	4
$4.00 Series - 150,000 shares	105.625	15	15
$3.70 Series - 40,000 shares	104.75	4	4
$3.50 Series - 130,000 shares	110.00	13	13
With par value of $100 per share —			
4.00% Series - 150,000 shares	101.00	15	15
4.25% Series - 50,000 shares	102.00	5	5
4.90% Series - 75,000 shares	102.00	8	8
4.92% Series - 50,000 shares	103.50	5	5
5.16% Series - 50,000 shares	102.00	5	5
1993 Auction - 300,000 shares	100.00 – note (c)	30	30
6.625% Series - 125,000 shares	100.00	12	12
Without par value and stated value of $25 per share —			
$1.735 Series - 1,657,500 shares	25.00	42	42
Total Preferred Stock Outstanding Not Subject to Mandatory Redemption		$235	$235

(a) Beginning February 15, 2003, eventually declining to $100 per share.
(b) In the event of voluntary liquidation, $105.50.
(c) Dividend rates, and the periods during which such rates apply, vary depending on the Company's selection of certain defined dividend period lengths. The average dividend rate during 1999 was 3.89%.

NOTE 7
Short-Term Borrowings

Short-term borrowings of the Company consist of bank loans (maturities generally on an overnight basis) and commercial paper (maturities generally within 10-45 days). At December 31, 1999 and 1998, $80 million and $59 million, respectively, of short-term borrowings were outstanding. The weighted average interest rates on borrowings outstanding at December 31, 1999 and 1998, were 6.3% and 4.9%, respectively.

At December 31, 1999, the Company had committed bank lines of credit aggregating $180 million (all of which was unused and available at such date) which make available interim financing at various rates of interest based on LIBOR, the bank certificate of deposit rate, or other options. These lines of credit are renewable annually at various dates throughout the year.

The Company also has a $300 million, short-term, bank credit agreement due in 2000, which permits the Company to borrow or to support a portion of the Company's commercial paper program. At December 31, 1999, all was unused and $240 million of such borrowing was available.

The Company has money pool agreements among its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained between regulated and nonregulated 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 intercompany balances, which are eliminated at the Ameren Corporation consolidated level.

NOTE 8
Long-Term Debt

In Millions	December 31, 1999	1998
First Mortgage Bonds – note (a)		
6¾% Series paid in 1999	$ –	$ 100
7⅛% Series W paid in 1999	–	50
8.33% Series due 2002	75	75
6⅜% Series Z due 2003	40	40
7.65% Series due 2003	100	100
6⅞% Series due 2004	188	188
7⅜% Series due 2004	85	85
7½% Series X due 2007	50	50
6¾% Series due 2008	148	148
7.61% 1997 Series due 2017	40	40
7.40% Series due 2020 – note (b)	60	60
8¾% Series due 2021	125	125
8¼% Series due 2022	104	104
8% Series due 2022	85	85
7.15% Series due 2023	75	75
7% Series due 2024	100	100
6.125% Series due 2028	60	60
5.45% Series due 2028 – note (b)	44	44
Other 5.375% - 7.05% due 2000 through 2008	158	168
	1,537	1,697
Environmental Improvement/Pollution Control Revenue Bonds		
1985 Series A due 2015 – note (c)	70	70
1985 Series B due 2015 – note (c)	57	57
1990 Series B 7.60% due 2013	32	32
1991 Series due 2020 – note (c)	43	43
1992 Series due 2022 – note (c)	47	47
1993 Series A 6⅜% due 2028	35	35
1993 Series C-1 due 2026 – note (c)	35	35
1998 Series A due 2033 – note (c)	60	60
1998 Series B due 2033 – note (c)	50	50
1998 Series C due 2033 – note (c)	50	50
Other 5.40% - 7.60% due 2014 through 2028	80	80
	559	559
Subordinated Deferrable Interest Debentures		
7.69% Series A due 2036 – note (d)	66	66
Unsecured Loans		
Commercial paper – note (e)	152	–
Credit agreements – note (f)	68	10
1991 Senior Medium Term Notes 8.60% due through 2005	41	47
1994 Senior Medium Term Notes 6.61% due through 2005	46	54
	307	111
Nuclear Fuel Lease	116	66
Unamortized Discount and Premium on Debt	(8)	(8)
Maturities Due Within One Year	(129)	(202)
Total Long-Term Debt	$2,448	$2,289

(a) At December 31, 1999, substantially all of the property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued.

(b) Environmental Improvement Series

(c) Interest rates, and the periods during which such rates apply, vary depending on the Company's selection of certain defined rate modes. The average interest rates for the year 1999 are as follows:

1985 Series A	*3.21%*
1985 Series B	*3.29%*
1991 Series	*3.65%*
1992 Series	*3.55%*
1993 Series	*3.34%*
1998 Series A	*3.49%*
1998 Series B	*3.48%*
1998 Series C	*3.46%*

(d) During the terms of the debentures, the Company may, under certain circumstances, defer the payment of interest for up to five years.

(e) A bank credit agreement, due 2002, permits AmerenUE to borrow or to support commercial paper borrowings up to $300 million. Interest rates will vary depending on market conditions.

(f) A bank credit agreement, due 2002, permits the Company to borrow up to $200 million. Interest rates will vary depending on market conditions and the Company's selection of various options under the agreement. At December 31, 1999, the average annualized interest rate was 6.4%.

Maturities of long-term debt through 2004 are as follows:

In Millions	*Principal Amount*
2000	$129
2001	45
2002	275
2003	160
2004	288

Amounts for years subsequent to 2000 do not include nuclear fuel lease payments since the amounts of such payments are not currently determinable.

NOTE 9
Income Taxes

Total income tax expense for 1999 resulted in an effective tax rate of 39% on earnings before income taxes (40% in 1998 and 38% in 1997).

Principal reasons such rates differ from the statutory federal rate:

	1999	*1998*	*1997*
Statutory federal income tax rate:	35%	35%	35%
Increases (Decreases) from:			
Depreciation differences	1	1	1
State tax	4	4	4
Other	(1)	–	(2)
Effective income tax rate	39%	40%	38%

Income tax expense components:

In Millions	*1999*	*1998*	*1997*
Taxes currently payable (principally federal):			
Included in operating expenses	$287	$303	$261
Included in other income — Miscellaneous, net	(3)	(6)	–
	284	297	261

Income tax expense components (continued):

In Millions	*1999*	*1998*	*1997*
Deferred taxes (principally federal):			
Included in operating expenses —			
Depreciation differences	3	(10)	(11)
Other	(23)	(17)	(7)
Included in other income —			
Other	(2)	2	10
	(22)	(25)	(8)
Deferred investment tax credit amortization:			
Included in operating expenses	(8)	(8)	(9)
Total income tax expense	$254	$264	$244

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.

The Company adjusts its 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:

In Millions	*1999*	*1998*
Net accumulated deferred income tax liabilities:		
Depreciation	$1,038	$1,036
Regulatory assets, net	433	433
Capitalized taxes and expenses	130	155
Deferred benefit costs	(58)	(48)
Other	21	12
Total net accumulated deferred income tax liabilities	$1,564	$1,588

NOTE 10
Retirement Benefits

The Company has a defined-benefit retirement plan covering substantially all of its employees. Benefits are based on the employees' years of service and compensation. The Company's plan is funded in compliance with income tax regulations and federal funding requirements.

On January 1, 1999, the AmerenUE and the AmerenCIPS pension plans combined to form the Ameren Retirement Plan. The AmerenUE and AmerenCIPS pension plans' information for 1998 and 1997 is presented separately. The Ameren plan covers qualified employees of the Company. Following is the pension plan information related to Ameren's plan as of December 31, 1999:

Pension costs for 1999 were $24 million, of which approximately 18% was charged to construction accounts.

FUNDED STATUS OF AMEREN'S PENSION PLAN:

In Millions	*1999*
Change in benefit obligation	
Net benefit obligation at beginning of year	$1,321
Service cost	33
Interest cost	91
Actuarial gain	(95)
Benefits paid	(93)
Net benefit obligation at end of year	1,257
Change in plan assets*	
Fair value of plan assets at beginning of year	1,372
Actual return on plan assets	146
Employer contributions	2
Benefits paid	(93)
Fair value of plan assets at end of year	1,427
Funded status – excess	(170)
Unrecognized net actuarial gain	310
Unrecognized prior service cost	(62)
Unrecognized net transition asset	7
Accrued pension cost at December 31	$ 85

* *Plan assets consist principally of common stocks and fixed income securities.*

COMPONENTS OF AMEREN'S NET PERIODIC BENEFIT COST:

In Millions	*1999*
Service cost	$ 33
Interest cost	91
Expected return on plan assets	(104)
Amortization of:	
Transition asset	(1)
Prior service cost	7
Actuarial gain	(2)
Net periodic benefit cost	$ 24

WEIGHTED-AVERAGE ASSUMPTIONS FOR ACTUARIAL PRESENT VALUE OF PROJECTED BENEFIT OBLIGATIONS:

	1999
Discount rate at measurement date	7.75%
Expected return on plan assets	8.50%
Increase in future compensation	4.75%

AmerenUE's plan covers qualified employees of AmerenUE as well as certain employees of Ameren Services Company. Following is the pension plan information related to AmerenUE's plan as of December 31:

Pension costs for the years 1998 and 1997, were $28 million and $24 million, respectively, of which approximately 19% and 17%, respectively, was charged to construction accounts.

FUNDED STATUS OF AMERENUE'S PENSION PLAN:

In Millions	*1998*
Change in benefit obligation	
Net benefit obligation at beginning of year	$ 999
Service cost	24
Interest cost	70
Amendments	10
Actuarial loss	38
Special termination benefit charge	7
Benefits paid	(88)
Net benefit obligation at end of year	1,060
Change in plan assets*	
Fair value of plan assets at beginning of year	1,006
Actual return on plan assets	122
Employer contributions	1
Benefits paid	(88)
Fair value of plan assets at end of year	1,041
Funded status – deficiency	19
Unrecognized net actuarial gain	121
Unrecognized prior service cost	(73)
Unrecognized net transition asset	6
Accrued pension cost at December 31	$ 73

* *Plan assets consist principally of common stocks and fixed income securities.*

COMPONENTS OF AMERENUE'S NET PERIODIC BENEFIT COST:

In Millions	*1998*	*1997*
Service cost	$ 24	$ 22
Interest cost	70	69
Expected return on plan assets	(75)	(71)
Amortization of:		
Transition asset	(1)	(1)
Prior service cost	6	7
Actuarial gain	(3)	(2)
Special termination benefit charge	7	–
Net periodic benefit cost	$ 28	$ 24

WEIGHTED-AVERAGE ASSUMPTIONS FOR ACTUARIAL PRESENT VALUE OF PROJECTED BENEFIT OBLIGATIONS:

	1998
Discount rate at measurement date	6.75%
Expected return on plan assets	8.5%
Increase in future compensation	4%

AmerenCIPS' plan covers substantially all employees of AmerenCIPS as well as certain employees of Ameren Services Company. In 1998, AmerenCIPS changed its measurement date for valuation of plan assets and liabilities to December 31. Following is the pension plan information related to AmerenCIPS' plan as of December 31:

Pension costs for the years 1998 and 1997 were $9 million and $5 million, respectively, of which approximately 19% in 1998 and 15% in 1997 was charged to construction accounts.

FUNDED STATUS OF AMERENCIPS' PENSION PLAN:

In Millions	*1998*
Change in benefit obligation	
Net benefit obligation at beginning of year	$249
Service cost	8
Interest cost	17
Amendments	5
Actuarial loss	8
Special termination benefit charge	5
Benefits paid	(31)
Net benefit obligation at end of year	261
Change in plan assets*	
Fair value of plan assets at beginning of year	319
Actual return on plan assets	38
Employer contributions	5
Benefits paid	(31)
Fair value of plan assets at end of year	331
Funded status – excess	(70)
Unrecognized net actuarial gain	73
Unrecognized prior service cost	(13)
Unrecognized net transition asset	2
Prepaid pension cost at December 31	$ (8)

* *Plan assets consist principally of common and preferred stocks, bonds, money market instruments and real estate.*

COMPONENTS OF AMERENCIPS' NET PERIODIC BENEFIT COST:

In Millions	*1998*	*1997*
Service cost	$ 8	$ 7
Interest cost	17	16
Expected return on plan assets	(22)	(19)
Amortization of prior service cost	1	1
Special termination benefit charge	5	-
Net periodic benefit cost	$ 9	$ 5

WEIGHTED-AVERAGE ASSUMPTIONS FOR ACTUARIAL PRESENT VALUE OF PROJECTED BENEFIT OBLIGATIONS:

	1998
Discount rate at measurement date	6.75%
Expected return on plan assets	8.5%
Increase in future compensation	4%

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees. The Company accrues the expected postretirement benefit costs during employees' years of service.

AmerenUE's plans cover qualified employees of AmerenUE as well as certain employees of Ameren Services Company. The following is information related to AmerenUE's postretirement benefit plans as of December 31:

AmerenUE's funding policy is to annually contribute the net periodic cost to a Voluntary Employee Beneficiary Association trust (VEBA). Postretirement benefit costs were $46 million for 1999, $43 million in 1998 and $44 million in 1997, of which approximately 18% in 1999 and 17% in 1998 and 1997 were charged to construction accounts. AmerenUE's transition obligation at December 31, 1999, is being amortized over the next 13 years.

The MoPSC and the ICC allow the recovery of postretirement benefit costs in rates to the extent that such costs are funded. In December 1995, AmerenUE established two external trust funds for retiree health care and life insurance benefits. In 1999, 1998 and 1997, claims were paid out of the plan trust funds.

FUNDED STATUS OF AMERENUE'S POSTRETIREMENT PLANS:

In Millions	*1999*	*1998*
Change in benefit obligation		
Net benefit obligation at beginning of year	$ 360	$ 333
Service cost	15	14
Interest cost	25	24
Actuarial (gain)/loss	(20)	9
Benefits paid	(26)	(20)
Net benefit obligation at end of year	354	360
Change in plan assets*		
Fair value of plan assets at beginning of year	110	81
Actual return on plan assets	4	8
Employer contributions	46	44
Unincorporated business income tax	–	(3)
Benefits paid	(26)	(20)
Fair value of plan assets at end of year	134	110
Funded status – deficiency	220	250
Unrecognized net actuarial gain	29	11
Unrecognized prior service cost	(3)	(3)
Unrecognized net transition obligation	(162)	(175)
Postretirement benefit liability at December 31	$ 84	$ 83

* *Plan assets consist principally of common stocks and fixed income securities.*

COMPONENTS OF AMERENUE'S NET PERIODIC BENEFIT COST:

In Millions	*1999*	*1998*	*1997*
Service cost	$ 15	$ 14	$ 12
Interest cost	25	24	23
Expected return on plan assets	(6)	(5)	(2)
Amortization of:			
Transition obligation	12	12	12
Actuarial gain	–	(2)	(1)
Net periodic benefit cost	$ 46	$ 43	$ 44

ASSUMPTIONS FOR THE OBLIGATION MEASUREMENTS:

	1999	*1998*
Discount rate at measurement date	7.75%	6.75%
Expected return on plan assets	8.5%	8.5%
Medical cost trend rate – initial	–	5.75%
– ultimate	5.25%	4.75%
Ultimate medical cost trend rate expected in year	2000	2000

A 1% increase in the medical cost trend rate is estimated to increase the net periodic cost and the accumulated postretirement benefit obligation approximately $4 million and $31 million, respectively. A 1% decrease in the medical cost trend rate is estimated to decrease the net periodic cost and the accumulated postretirement benefit obligation approximately $4 million and $31 million, respectively.

AmerenCIPS' plans cover substantially all employees of AmerenCIPS as well as certain employees of Ameren Services Company. The following is information related to AmerenCIPS' postretirement benefit plans as of December 31:

AmerenCIPS' funding policy is to fund the two VEBAs and the 401(h) account established within the AmerenCIPS retirement income trust with the lesser of the net periodic cost or the amount deductible for federal income tax purposes. In 1998, AmerenCIPS changed its measurement date for valuation of plan assets and liabilities to December 31. Postretirement benefit costs were $3 million for 1999, $6 million for 1998 and $12 million for 1997, of which approximately 10% was charged to construction accounts in 1999, 20% in 1998, and 17% in 1997. AmerenCIPS' transition obligation at December 31, 1999 is being amortized over the next 13 years.

The ICC allows the recovery of postretirement benefit costs in rates to the extent that such costs are funded.

FUNDED STATUS OF AMERENCIPS' POSTRETIREMENT PLANS:

In Millions	*1999*	*1998*
Change in benefit obligation		
Net benefit obligation at beginning of year	$ 152	$ 140
Service cost	3	3
Interest cost	9	10
Actuarial (gain)/loss	(22)	4
Benefits paid	(4)	(5)
Net benefit obligation at end of year	138	152
Change in plan assets*		
Fair value of plan assets at beginning of year	128	115
Actual return on plan assets	10	16
Employer contributions	1	4
401(h) transfer	–	(2)
Benefits paid	(4)	(5)
Fair value of plan assets at end of year	135	128
Funded status – deficiency	3	24
Unrecognized net actuarial gain	75	58
Unrecognized net transition obligation	(71)	(76)
Postretirement benefit liability at December 31	$ 7	$ 6

* *Plan assets consist principally of common and preferred stocks, bonds, money market instruments and real estate.*

COMPONENTS OF AMERENCIPS' NET PERIODIC BENEFIT COST:

In Millions	*1999*	*1998*	*1997*
Service cost	$ 3	$ 3	$ 4
Interest cost	9	10	10
Expected return on plan assets	(9)	(8)	(5)
Amortization of:			
Transition obligation	6	5	5
Actuarial gain	(6)	(4)	(2)
Net periodic benefit cost	$ 3	$ 6	$12

ASSUMPTIONS FOR THE OBLIGATION MEASUREMENTS:

	1999	1998
Discount rate at measurement date	7.75%	6.75%
Expected return on plan assets	8.5%	8.5%
Medical cost trend rate - initial	-	5.75%
- ultimate	5.25%	4.75%
Ultimate medical cost trend rate expected in year	2000	2000

A 1% increase in the medical cost trend rate is estimated to increase the net periodic cost and the accumulated postretirement benefit obligation approximately $2 million and $20 million, respectively. A 1% decrease in the medical cost trend rate is estimated to decrease the net periodic cost and the accumulated postretirement benefit obligation approximately $2 million and $20 million, respectively.

NOTE 11

Stock Option Plans

In 1998, the Company adopted a long-term incentive plan (the Plan) for eligible employees, replacing the plan previously in place at AmerenUE. The Plan provides for the grant of options, performance awards, restricted stock, dividend equivalents and stock appreciation rights. Under the terms of the Plan, 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 acceleration of exercisability of the options upon the occurrence of certain events, including retirement. Outstanding options expire on various dates through 2009. Under the Plan, subject to adjustment as provided in the Plan, four million shares have been authorized to be issued or delivered under the Company's Plan. In accordance with APB 25, no compensation cost has been recognized for the Company's stock compensation plans. The Company has adopted the disclosure-only method of fair value data under SFAS 123, "Accounting for Stock-Based Compensation." If the fair value-based accounting method under this statement had been used to account for stock-based compensation cost, the effects on 1999, 1998, and 1997 net income and earnings per share would have been immaterial.

The following table summarizes stock option activity during 1999, 1998 and 1997:

	1999	
	Shares	*Weighted Average Exercise Price*
Outstanding at beginning of year	1,095,180	$39.41
Granted	768,100	36.63
Exercised	11,162	37.20
Cancelled or expired	18,010	42.45
Outstanding at end of year	1,834,108	38.22
Exercisable at end of year	391,456	39.06

	1998		*1997*	
	Shares	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*
Outstanding at beginning of year	496,070	$39.24	307,390	$39.71
Granted	700,600	39.25	195,880	38.50
Exercised	72,390	36.81	-	-
Cancelled or expired	29,100	39.28	7,200	39.56
Outstanding at end of year	1,095,180	39.41	496,070	39.24
Exercisable at end of year	173,653	39.91	134,785	38.55

Additional information about stock options outstanding at December 31, 1999:

Exercise Price	*Outstanding Shares*	*Weighted Average Life (Years)*	*Exercisable Shares*
$35.50	800	5.6	600
35.875	79,225	4.8	59,375
36.625	768,100	8.5	60,700
38.50	175,853	6.0	68,701
39.25	662,500	7.2	111,150
39.8125	5,300	8.5	-
43.00	142,330	4.8	90,930

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*
2/12/99	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 12

Commitments and Contingencies

The Company is engaged in a capital program under which expenditures averaging approximately $653 million, including AFC, are anticipated during each of the next five years. This estimate includes capital expenditures for the purchase of new combustion turbine generators, as well as expenditures that will be incurred by the Company to meet new air quality standards for ozone and particulate matter, as discussed later in this Note.

The Company has committed to purchase combustion turbine generators (CTs), which will add more than 2,700 megawatts to its net peaking capacity and are expected to cost approximately $1.2 billion. CTs with a total capacity of approximately 590 megawatts are planned to be installed in 2000, 560 megawatts in 2001, 590 megawatts in 2002, and 325 megawatts each in 2003 through 2005. Except for nearly 200 megawatts, the new capacity is expected to be operated by the Company's proposed new nonregulated generating subsidiary (see Note 2 – Regulatory Matters for further information).

The Company has commitments for the purchase of coal under long-term contracts. Coal contract commitments, including transportation costs, for 2000 through 2004 are estimated to total $2.1 billion. Total coal purchases, including transportation costs, for 1999, 1998 and 1997 were $603 million, $567 million and $547 million, respectively. The Company also has existing contracts with pipeline and natural gas suppliers to provide, transport and store natural gas for distribution and electric generation. Gas-related contract cost commitments for 2000 through 2004 are estimated to total $122 million. Total delivered natural gas costs were $131 million for 1999, $119 million for 1998, and $161 million for 1997. The Company's nuclear fuel commitments for 2000 through 2004, including uranium concentrates, conversion, enrichment and fabrication, are expected to total $73 million, and are expected to be substantially financed under the nuclear fuel lease. Nuclear fuel expenditures for 1999, 1998 and 1997, were $22 million, $20 million and $35 million, respectively. Additionally, the Company has long-term contracts with other utilities to purchase electric capacity. These commitments for 2000 through 2004 are estimated to total $241 million. During 1999, 1998 and 1997, electric capacity purchases were $44 million, $38 million and $36 million, respectively.

In the fourth quarter 1999, AmerenCIPS and two of its coal suppliers executed agreements to terminate their existing coal supply contracts, effective December 31, 1999. Under these agreements, AmerenCIPS has made termination payments to the suppliers totaling approximately $52 million. These termination payments were recorded as a nonrecurring charge in the fourth quarter of 1999, equivalent to $31 million, after income taxes, or 23 cents per share. Total pretax fuel cost savings from these termination agreements are estimated to be $183 million (or $131 million net of the termination payments) through 2010, which is the maximum period that would have remained on any of the terminated coal supply contracts. Approximately $66 million of pretax fuel cost savings is expected to be realized over the next three years.

During 1996, AmerenCIPS restructured its contract with one of its major coal suppliers. In 1997, the Company paid a $70 million restructuring payment to the supplier, which allowed it to purchase at market prices low-sulfur, non-Illinois coal through the supplier (in substitution for the high-sulfur Illinois coal AmerenCIPS was obligated to purchase under the original contract). Under the 1997 restructuring, the Company received options for future purchases of low-sulfur, non-Illinois coal from the supplier through 1999 at set negotiated prices.

By switching to low-sulfur coal, the Company was able to discontinue operating a generating plant scrubber. The benefits of the 1999 restructuring include lower cost coal, avoidance of significant capital expenditures to renovate the scrubber, and elimination of scrubber operating and maintenance costs (offset by scrubber retirement expenses). The net benefits of restructuring are expected to exceed $100 million through 2007. In December 1996, the ICC entered an order approving the switch to non-Illinois coal, recovery of the restructuring payment plus associated carrying costs (Restructuring Charges) through the retail Fuel Adjustment Clause (FAC) over six years, and continued recovery in rates of the undepreciated scrubber investment, plus costs of removal. Additionally, in May 1997 the FERC approved recovery of the wholesale portion of the Restructuring Charges through the wholesale FAC. As a result of the ICC and FERC orders, the Company classified $72 million of the Restructuring Charges as a regulatory asset and, through December 1997, recovered approximately $10 million of the Restructuring Charges through the retail FAC and from wholesale customers. In November 1997, the ICC order was reversed on appeal by the Illinois Third District Appellate Court. The Illinois Supreme Court issued a final decision in December 1998 reversing the Appellate Court's opinion and affirming the ICC's order allowing the recovery of the Restructuring Charges through the retail FAC.

The recoverability of the Restructuring Charges under the retail FAC in Illinois was impacted by the Illinois Law. Among other things, the Illinois Law provides utilities with the option to eliminate the retail FAC and limits the ability of utilities to file a full rate case for its aggregate revenue requirements. After evaluating the impact of the Illinois Law on the future recoverability of the Company's Restructuring Charges through future rates, the Company wrote off the unamortized balance of the Illinois retail portion of its Restructuring Charges as of December 31, 1997 ($34 million, net of income taxes). See Note 2 - Regulatory Matters for further information.

The Company's insurance coverage for Callaway Nuclear Plant at December 31, 1999 was as follows:

TYPE AND SOURCE OF COVERAGE

In Millions	*Maximum Coverages*	*Maximum Assessments for Single Incidents*
Public Liability:		
American Nuclear Insurers	$ 200	$ –
Pool Participation	9,338	88 (a)
	$9,538 (b)	$88
Nuclear Worker Liability:		
American Nuclear Insurers	$ 200 (c)	$ 3
Property Damage:		
Nuclear Electric Insurance Ltd.	$2,750 (d)	$11
Replacement Power:		
Nuclear Electric Insurance Ltd.	$ 490 (e)	$ 2

(a) Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended, (Price-Anderson). Subject to retrospective assessment with respect to loss from an incident at any U.S. reactor, payable at $10 million per year. Price-Anderson expires in 2002.
(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 12 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, the Company will self-insure the risk. Although the Company has no reason to anticipate a serious nuclear incident, if one did occur, it could have a material, but indeterminable, adverse effect on the Company's financial position, results of operations or liquidity.

Under Title IV of the Clean Air Act Amendments of 1990, the Company is required to significantly reduce total annual sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions by the year 2000. By switching to low-sulfur coal, early banking of emissions credits and installing advanced NOx reduction combustion technology, the Company is meeting these requirements.

In July 1997, the United States Environmental Protection Agency (EPA) issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. In May 1999, the U.S. Court of Appeals for the District of Columbia remanded the regulations back to the EPA for review. Litigation regarding appeals of these regulations is ongoing. New ambient standards may result in additional significant reductions in SO2 and NOx emissions from the Company's power plants by 2007. At this time, the Company is unable to predict the ultimate impact of these revised air quality standards on its future financial condition, results of operations or liquidity.

In an attempt to lower ozone levels across the eastern United States, the EPA issued the implementation of regulations in September 1998 to reduce NOx emissions from coal-fired boilers and other sources in 22 states, including Missouri and Illinois (where all of the Company's coal-fired power plant boilers are located). The implementation of these regulations has been delayed by the U.S. Court of Appeals for the District of Columbia until a legal challenge brought by various industries and states has been resolved. The proposed regulations mandate a 75% reduction from 1990 levels by the year 2003 and require states to develop plans to reduce NOx emissions to help alleviate ozone problem areas. The NOx emissions reductions already achieved on several of the Company's coal-fired power plants will help to reduce the costs of compliance with these regulations. However, preliminary analysis of the regulations indicate that selective catalytic reduction technology may be required for some of the Company's units, as well as other additional controls.

Currently, the Company estimates that its additional capital expenditures to comply with the final NOx regulations could range from $250 million to $300 million over the period from 1999 to 2003. Associated operations and maintenance expenditures could increase $10 million to $15 million annually, beginning in 2003. The Company is exploring alternatives to comply with these new regulations in order to minimize, to the extent possible, its capital costs and operating expenses. The Company is unable to predict the ultimate impact of these standards on its future financial condition, results of operations or liquidity.

In November 1998, the United States signed an agreement with numerous other countries (the Kyoto Protocol) containing certain environmental provisions, which would require decreases in greenhouse gases in an effort to address the "global warming" issue. The Kyoto Protocol has not been ratified by the United States Senate. Implementation of the Kyoto Protocol in its present form would likely result in significantly higher capital costs and operations and maintenance expenses by the Company. At this time, the Company is unable to determine the impact of these proposals on the Company's future financial condition, results of operations or liquidity.

As of December 31, 1999, the Company's utility operating subsidiaries were designated as potentially responsible parties (PRP) by federal and state environmental protection agencies at seven hazardous waste sites. Other hazardous waste sites have been identified for which the Company may be responsible but has not been designated a PRP.

Costs relating to studies and remediation and associated legal and litigation expenses at the former manufactured gas plant sites located in Illinois are being accrued and deferred rather than expensed currently, pending recovery through environmental adjustment clause rate riders approved by the ICC. Through December 31, 1999, the total of the costs deferred, net of recoveries from insurers and through environmental adjustment clause riders, was $13 million.

The ICC has instituted reconciliation proceedings to review the Company's environmental remediation activities to determine whether the revenues collected from customers under its environmental adjustment clause rate riders were consistent with the amount of remediation costs prudently and properly incurred. Amounts found to have been incorrectly included under the riders would be subject to refund. Rulings from the ICC are pending with respect to these proceedings applicable to the years 1993 through 1998. The reconciliation proceedings relating to the Company's 1999 environmental remediation activities will commence by the ICC in 2000.

The Company continually reviews remediation costs that may be required for all of these sites. Any unrecovered environmental costs are not expected to have a material adverse effect on the Company's financial position, results of operations or liquidity.

The International Union of Operating Engineers Local 148 and the International Brotherhood of Electrical Workers Local 702 filed unfair labor practice charges with the National Labor Relations Board (NLRB), relating to the legality of the 1993 lockout of both unions by AmerenCIPS. The NLRB issued complaints against AmerenCIPS concerning its lockout. Both unions sought, among other things, back pay and other benefits for the period of the lockout. At that time, the Company estimated the amount of back pay and other benefits for both unions to be approximately $17 million. In August 1998, a three-member panel of the NLRB reversed the May 1996 decision of its administrative law judge and ruled in favor of AmerenCIPS holding that the lockout was lawful. In April 1999, the unions filed petitions for review with the U.S. Court of Appeals for the District of Columbia Circuit of the NLRB's August 1998 decision. This appeal is pending. The Company continues to believe that the lockout was both lawful and reasonable and that the final resolution of the dispute will not have a material adverse effect on its financial position, results of operations or liquidity.

Certain employees of the Company are represented by the International Brotherhood of Electrical Workers and the International Union of Operating Engineers. These employees comprise approximately 70% of the Company's workforce. New contracts with collective bargaining units representing approximately 60% of these employees were ratified in 1999 with terms expiring in 2002. Negotiations with collective bargaining units representing approximately 38% of those union employees are currently underway. The current collective bargaining agreements which expired in July 1999 have been extended to facilitate those negotiations. At this time, the Company is unable to predict the impact of these negotiations on its future financial condition, results of operations or cash flows. The collective bargaining agreement covering the remaining 2% of represented employees expires in 2000.

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, the Company is unable to predict the impact of these changes on the Company's future financial condition, results of operations or liquidity. See Note 2 - Regulatory Matters for further information.

The Company is involved in other legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business, some of which involve substantial amounts. The Company believes that the final disposition of these proceedings will not have a material adverse effect on its financial position, results of operations or liquidity.

NOTE 13
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 per nuclear-generated kilowatthour sold for future disposal of spent fuel. Electric 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. The Company has sufficient storage capacity at the Callaway Plant site until 2020 and has 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 the Callaway Plant.

Electric rates charged to customers provide for recovery of Callaway Plant 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 using the DECON (immediate dismantlement) method. Decommissioning costs, including decontamination, dismantling and site restoration, are estimated to be $509 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 1999, 1998 and 1997. Every three years, the MoPSC and ICC require the Company 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 1999. 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% annually through the date of decommissioning. If the assumed return on trust assets is not earned, the Company believes 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 staff of the SEC has questioned certain current accounting practices of the electric utility industry, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the Financial Accounting Standards Board has agreed to review the accounting for removal costs, including decommissioning. The Company does not expect that changes in the accounting for nuclear decommissioning costs will have a material effect on its financial position, results of operations or liquidity.

NOTE 14
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 the Company 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, time value of money and volatility factors.

Carrying amounts and estimated fair values of the Company's financial instruments at December 31:

	1999		*1998*	
In Millions	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Marketable securities	$ –	$ –	$ 14	$ 14
Preferred stock	235	192	235	235
Long-term debt (including current portion)	2,577	2,552	2,491	2,659

The Company has investments in debt and equity securities that are held in trust funds for the purpose of funding the nuclear decommissioning of Callaway Nuclear Plant (see Note 13 - Callaway Nuclear Plant). The Company has classified these investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1999 and 1998. In 1999, 1998 and 1997, the proceeds from the sale of investments were $83 million, $29 million and $24 million, respectively. Using the specific identification method to determine cost, the gross realized gains on those sales were approximately $11 million for 1999, and $2 million for 1998 and 1997. 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 used by the Company to account for the decommissioning costs recovered in rates.

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

1999 In Millions Security Type	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
Debt securities	$ 67	$ –	$ –	$ 67
Equity securities	45	73	–	118
Cash equivalents	2	–	–	2
	$114	$73	$ –	$187

1998 In Millions Security Type	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
Debt securities	$ 48	$ 4	$ –	$ 52
Equity securities	46	62	–	108
Cash equivalents	2	–	–	2
	$ 96	$66	$ –	$162

The contractual maturities of investments in debt securities at December 31, 1999 were as follows:

In Millions	Cost	Fair Value
1 year to 5 years	$ 6	$ 6
5 years to 10 years	30	30
Due after 10 years	31	31
	$67	$ 67

NOTE 15
Segment Information

In 1998, the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information." Ameren's principal business segment is comprised of the two regulated utility operating companies that provide electric and gas service in portions of Missouri and Illinois. The other reportable segment includes the nonregulated subsidiaries, as well as the Company's 60% interest in Electric Energy, Inc.

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. The Company evaluates the performance of its segments and allocates resources to them, based on revenues, operating income and net income.

The table below presents information about the reported revenues, operating income, net income, and total assets of Ameren for the years ended December 31:

1999 In Millions	Regulated Utilities	All Other	Reconciling Items	Total
Revenues	$ 3,455	$243	$(174)*	$3,524
Net income	384	1	–	385
Total assets	8,825	435	(82)	9,178

1998 In Millions	Regulated Utilities	All Other	Reconciling Items	Total
Revenues	$3,230	$190	$(102)*	$3,318
Net income	380	6	–	386
Total assets	8,594	237	16	8,847
1997 In Millions				
Revenues	$3,139	$243	$(55)*	$3,327
Net income	321	14	–	335
Total assets	8,591	243	(6)	8,828

*Elimination of intercompany revenues.

Specified items included in segment profit/loss for the year ended December 31:

1999 In Millions	Regulated Utilities	All Other	Total
Interest expense	$163	$9	$172
Depreciation, depletion and amortization expense	337	12	349
Income tax expense	261	(2)	259
1998 In Millions			
Interest expense	$170	$9	$179
Depreciation, depletion and amortization expense	334	14	348
Income tax expense	263	5	268
1997 In Millions			
Interest expense	$168	$10	$178
Depreciation, depletion and amortization expense	331	15	346
Income tax expense	226	8	234
Extraordinary items	(52)	–	(52)

Specified items related to segment assets as of December 31:

1999 In Millions	Regulated Utilities	All Other	Total
Expenditures for additions to long-lived assets	$342	$179	$521
1998 In Millions			
Expenditures for additions to long-lived assets	$290	$31	$321
1997 In Millions			
Expenditures for additions to long-lived assets	$375	$6	$381

Selected Consolidated Financial Information

Millions of Dollars Except Share and Per Share Amounts and Ratios	*1999*	*1998*	*1997*	*1996*	*1995*	*1994*
Results of Operations *Year ended December 31,*						
Operating revenues	$3,524	$3,318	$3,327	$3,328	$3,236	$3,270
Operating expenses	2,961	2,747	2,744	2,752	2,658	2,685
Operating income	563	571	582	576	578	585
Income before extraordinary charge	385	386	387	372	373	391
Extraordinary charge, net of income taxes	–	–	52	–	–	–
Net income	385	386	335	372	373	391
Average common shares outstanding	137,215,462	137,215,462	137,215,462	137,215,462	137,215,462	137,253,617
Assets, Obligations and Equity Capital *December 31,*						
Total assets	$9,178	$8,847	$8,828	$8,933	$8,788	$8,629
Long-term debt obligations	2,448	2,289	2,506	2,335	2,373	2,413
Preferred stock subject to mandatory redemption	–	–	–	1	1	1
Preferred stock not subject to mandatory redemption	235	235	235	298	298	298
Common equity	3,090	3,056	3,019	3,016	2,971	2,917
Financial Indices *Year ended December 31,*						
Earnings per share of common stock before extraordinary charge	$2.81	$2.82	$2.82	$2.71	$2.72	$2.85
Extraordinary charge, net of income taxes	–	–	$(.38)	–	–	–
Earnings per share of common stock (based on average shares outstanding)	$2.81	$2.82	$2.44	$2.71	$2.72	$2.85
Dividend payout ratio	90%	90%	99%	88%	86%	80%
Return on average common stock equity	12.56%	12.82%	11.14%	12.51%	12.76%	13.69%
Ratio earnings to fixed charges						
AmerenUE	5.64	4.99	4.70	4.68	4.78	4.68
AmerenCIPS	2.98	4.13	3.64	4.30	4.41	4.93
Book value per common share	$22.52	$22.27	$22.00	$21.98	$21.65	$21.25
Capitalization Ratios *December 31,*						
Common equity	53.5%	54.8%	52.4%	53.4%	52.6%	51.8%
Preferred stock	4.1	4.2	4.1	5.3	5.3	5.3
Long-term debt	42.4	41.0	43.5	41.3	42.1	42.9
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Electric Operating Statistics

Year Ended December 31,	*1999*	*1998*	*1997*	*1996*	*1995*	*1994*
Electric Operating Revenues *Millions*						
Residential	$1,097	$1,125	$1,064	$1,070	$1,073	$1,014
Commercial	956	966	927	920	906	884
Industrial	505	511	500	500	496	487
Wholesale	90	91	91	91	87	84
Other	24	23	24	28	28	22
Native	2,672	2,716	2,606	2,609	2,590	2,491
Interchange	417	240	224	280	230	243
EEI	177	152	207	198	201	276
Miscellaneous	60	29	47	22	20	20
Credit to customers	(38)	(43)	(20)	(47)	(33)	—
TOTAL ELECTRIC OPERATING REVENUES	$3,288	$3,094	$3,064	$3,062	$3,008	$3,030
Kilowatthour Sales *Millions*						
Residential	14,863	15,188	14,325	14,418	14,086	13,282
Commercial	15,418	15,555	14,990	14,872	14,464	14,043
Industrial	11,549	11,582	11,404	11,191	10,971	10,728
Wholesale	2,492	2,446	2,323	2,328	2,248	2,137
Other	303	303	317	305	316	301
Native	44,625	45,074	43,359	43,114	42,085	40,491
Interchange	12,881	8,075	9,402	10,768	8,176	8,080
EEI	9,270	8,296	11,220	10,554	10,850	14,594
TOTAL KILOWATTHOUR SALES	66,776	61,445	63,981	64,436	61,111	63,165
Electric Customers *End of Year*						
Residential	1,298,008	1,289,548	1,282,042	1,275,534	1,267,976	1,258,757
Commercial	188,503	181,678	180,206	176,621	173,810	171,072
Industrial	6,188	5,926	6,554	6,660	6,782	6,750
Wholesale	20	20	21	20	21	21
Miscellaneous	2,388	2,193	2,381	2,398	2,434	2,406
TOTAL ELECTRIC CUSTOMERS	1,495,107	1,479,365	1,471,204	1,461,233	1,451,023	1,439,006
Residential Customer Data *Average*						
Kilowatthours used	11,827	11,986	11,215	11,354	11,152	10,606
Annual electric bill	$859.53	$873.28	$833.34	$842.82	$849.62	$809.27
Revenue per kilowatthour	7.27¢	7.29¢	7.38¢	7.30¢	7.62¢	7.63¢
Gross Instantaneous Peak Demand *Megawatts*						
AmerenUE	8,831	8,429	8,055	8,085	7,965	7,430
AmerenCIPS	2,217	2,163	1,923	1,892	1,940	1,854
Capability at Time of Peak, Including Net Purchases and Sales *Megawatts*						
AmerenUE	9,141	9,027	8,950	9,120	8,714	8,469
AmerenCIPS	2,556	2,417	2,491	2,519	2,489	2,510
Generating Capability at Time of Peak *Megawatts*						
AmerenUE	8,352	8,282	8,279	8,244	8,184	8,057
AmerenCIPS	3,027	3,040	3,033	3,033	3,018	3,018
Coal Burned *Tons*	23,638,000	22,959,000	21,392,000	20,062,000	17,715,000	16,885,000
Price per Ton of Coal *Average*	$20.34	$21.29	$23.54	$25.25	$26.86	$28.02
Source of Energy Supply						
Coal	85.4%	83.5%	83.8%	79.6%	76.3%	76.2%
Nuclear	17.9	17.7	19.3	19.2	18.3	23.0
Hydro	3.1	3.8	2.7	2.8	3.6	3.9
Purchased and interchanged, net	(6.4)	(5.0)	(5.8)	(1.6)	1.8	(3.1)
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Gas Operating Statistics

Year Ended December 31	1999	1998	1997	1996	1995	1994
Natural Gas Operating Revenues *Millions*						
Residential	$146	$135	$150	$161	$137	$138
Commercial	52	50	55	61	51	53
Industrial	18	19	22	21	18	24
Off system sales	4	3	13	–	–	–
Miscellaneous	8	10	10	11	11	10
TOTAL NATURAL GAS OPERATING REVENUES	$228	$217	$250	$254	$217	$225
MMBtu Sales *Millions*						
Residential	21	21	23	27	24	23
Commercial	8	8	9	11	10	10
Industrial	4	6	6	5	5	6
Off system sales	1	1	5	–	–	–
TOTAL MMBTU SALES	34	36	43	43	39	39
Natural Gas Customers *End of Year*						
Residential	267,086	265,405	263,588	260,989	257,848	254,328
Commercial	29,247	30,245	30,147	29,911	29,446	29,037
Industrial	436	407	412	402	378	351
TOTAL NATURAL GAS CUSTOMERS	296,769	296,057	294,147	291,302	287,672	283,716
Peak Day Throughput *Thousands of MMBtus*						
AmerenCIPS	247	229	281	302	270	303
AmerenUE	184	157	181	189	159	179
TOTAL PEAK DAY THROUGHPUT	431	386	462	491	429	482

Ameren Corporation and Subsidiaries Officers and Directors

Officers

AMEREN CORPORATION

Charles W. Mueller
Chairman, President and Chief Executive Officer

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Senior Vice President, Finance

Steven R. Sullivan
Vice President, General Counsel and Secretary

Warner L. Baxter
Vice President and Controller

Jerre E. Birdsong
Treasurer

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Vice President, Power Plants

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Vice President, Nuclear Operations

William C. Shores
Vice President, Customer Services - Metropolitan

AMERENCIPS

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President and Chief Executive Officer

Gilbert W. Moorman
Vice President, Regional Operations

Jerry L. Simpson
Vice President, Power Operations

AMEREN SERVICES

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Senior Vice President

Daniel F. Cole
Senior Vice President

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Senior Vice President, Customer Services

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Vice President, Information Technology

Donald W. Capone
Vice President, Engineering & Construction
(retired December 31, 1999)

William J. Carr
Vice President, Customer Services - Regional/Distribution Services Support

Jimmy L. Davis
Vice President, Customer Services - Gas Support

Jean M. Hannis
Vice President, Human Resources

R. Alan Kelley
Vice President, Energy Supply

Michael J. Montana
Vice President, Supply Services

Craig D. Nelson
Vice President, Corporate Planning

Gregory L. Nelson
Vice President, Tax

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

David A. Whiteley
Vice President, Engineering & Construction
(effective January 1, 2000)

Samuel E. Willis
Vice President, Industrial Relations

Ronald C. Zdellar
Vice President, Customer Services - Division Support

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President

Baxter A. Gillette
Vice President, Risk Management

Clarence J. Hopf, Jr.
Vice President, Energy Trading

Brian Rettenmaier
Controller

Board of Directors

AMEREN CORPORATION

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Retired Chairman and Chief Executive Officer - Union Electric Company

Clifford L. Greenwalt [1]
Retired President and Chief Executive Officer - CIPSCO Incorporated

Thomas A. Hays [1]
Retired Deputy Chairman - The May Department Stores Company

Richard A. Liddy [2]
Chairman, President and Chief Executive Officer - GenAmerica Corporation, a provider of insurance products and services

Gordon R. Lohman [1]
Retired Chairman, President and Chief Executive Officer - AMSTED Industries Incorporated

Richard A. Lumpkin [2]
Chairman, President and Chief Executive Officer - Illinois Consolidated Telephone Company, a diversified telecommunications company

John Peters MacCarthy [1]
Retired Chairman and Chief Executive Officer - Boatmen's Trust Company

Hanne M. Merriman
Principal - Hanne Merriman Associates, a retail business consulting firm

Paul L. Miller, Jr. [2]
President and Chief Executive Officer - P.L. Miller and Associates, a management consulting firm

Charles W. Mueller [1]
Chairman of the Board, President & Chief Executive Officer - Ameren Corporation

Robert H. Quenon
Retired Chairman of the Board - Peabody Holding Company, Inc

Harvey Saligman [2]
Retired Managing Partner - Cynwyd Investments

Janet McAfee Weakley [1,2]
President - Janet McAfee, Inc., a residential real estate company

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

1 Member of Executive Committee
2 Member of Auditing Committee

ADVISERS TO THE BOARD

Charles J. Dougherty
Retired Chairman and Chief Executive Officer - Union Electric Company

Thomas H. Jacobsen
Chairman-Firstar Corporation, a bank holding company

Investor Information

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 116,922 for Ameren at December 31, 1999. The following includes the price ranges and dividends paid per common share for AEE during 1999 and 1998.

AEE 1999

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$ $42\ ^{15}/_{16}$	$ $36\ ^{3}/_{16}$	$ $36\ ^{3}/_{16}$	$63\ ^{1}/_{2}$¢
June 30	$40\ ^{15}/_{16}$	$35\ ^{13}/_{16}$	$38\ ^{3}/_{8}$	$63\ ^{1}/_{2}$
September 30	$40\ ^{3}/_{4}$	$36\ ^{7}/_{8}$	$37\ ^{13}/_{16}$	$63\ ^{1}/_{2}$
December 31	$39\ ^{7}/_{8}$	32	$32\ ^{3}/_{4}$	$63\ ^{1}/_{2}$

AEE 1998

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$ $43\ ^{1}/_{8}$	$ $35\ ^{9}/_{16}$	$ $42\ ^{1}/_{8}$	$63\ ^{1}/_{2}$¢
June 30	$42\ ^{9}/_{16}$	$37\ ^{5}/_{8}$	$39\ ^{3}/_{4}$	$63\ ^{1}/_{2}$
September 30	$42\ ^{1}/_{4}$	37	$41\ ^{15}/_{16}$	$63\ ^{1}/_{2}$
December 31	$44\ ^{5}/_{16}$	$39\ ^{1}/_{16}$	$42\ ^{11}/_{16}$	$63\ ^{1}/_{2}$

Annual Meeting

The annual meeting of Ameren, Union Electric Company and Central Illinois Public Service Company stockholders will convene at 9 a.m., Tuesday, April 25, 2000, at Powell Symphony Hall, 718 North Grand Boulevard, St. Louis, Missouri.

DRPlus

Through DRPlus — Ameren's dividend reinvestment and stock purchase plan — stockholders, customers and employees of Ameren and its subsidiaries can:

- make cash investments by check or automatic direct debit to their bank accounts to purchase Ameren common stock, totalling 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.

If you have not yet exchanged your Union Electric Company or CIPSCO Incorporated common stock certificates for Ameren stock certificates, please contact the Investor Services Department. 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 and Central Illinois Public Service Company preferred stockholders can have their cash dividends automatically credited 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, visit Ameren's home page on the Internet. 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 standard time). Please write or call:

Ameren Services Company
Investor Services Department
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.

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Design and Photography: Obata Design, Inc.
Printed on Recycled Paper

Ameren

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