AMEREN CORP
Form 8-K
February 14, 2002

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported):
February 14, 2002

AMEREN CORPORATION
(Exact name of registrant as specified in its charter)

Missouri	1-14756	43-1723446
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

1901 Chouteau Avenue, St. Louis, Missouri 63103
(Address of principal executive offices and Zip Code)

Registrant's telephone number, including area code: (314) 621-3222

ITEM 5. OTHER EVENTS AND REGULATION FD DISCLOSURE

On February 13, 2002, Ameren Corporation (the "Registrant") filed the following with the Securities and Exchange Commission as exhibits to this Current Report on Form 8-K: (i) consolidated financial statements as of December 31, 2001 and 2000, and for each of the three years in the period ended December 31, 2001, and the report thereon of PricewaterhouseCoopers LLP, independent accountants, and (ii) the related Management's Discussion and

Analysis of Financial Condition and Results of Operations.

ITEM 7. EXHIBITS

(c) Exhibits.

23	Consent of Independent Accountants.
99.1	The Registrant's consolidated financial statements as of December 31, 2001 and 2000, and for each of the three years in the period ended December 31, 2001, and the report thereon of PricewaterhouseCoopers LLP, independent accountants.
99.2	The Registrant's Management's Discussion and Analysis of Financial Condition and Results of Operations.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AMEREN CORPORATION
(Registrant)

By /s/ Martin J. Lyons

Martin J. Lyons
Controller
(Principal Accounting Officer)

Date: February 14, 2002

Exhibit Index

Exhibit No.	Description
23	- Consent of Independent Accountants.
99.1	- The Registrant's consolidated financial statements as of December 31, 2001 and 2000, and for each of the three years in the period ended December 31, 2001, and the report thereon of PricewaterhouseCoopers LLP, independent

accountants.

99.2 - The Registrant's Management's Discussion and Analysis of Financial Condition and Results of Operations.

EXHIBIT 23

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-43737, 333-43743, 333-50793 and 333-72156) and the Registration Statement on Form S-3 (No. 333-39400) of Ameren Corporation of our report dated February 1, 2002 relating to the consolidated financial statements, which appears in the Current Report on Form 8-K of Ameren Corporation dated February 14, 2002.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 14, 2002

EXHIBIT 99.1

Report of Independent Accountants

To the Board of Directors and Shareholders
of Ameren Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of cash flows and of common stockholders' equity present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 2001, and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 1, 2002

AMEREN CORPORATION
CONSOLIDATED BALANCE SHEET
(Thousands of Dollars, Except Share Amounts)

ASSETS	December 31, 2001	December 31, 2000
Property and plant, at original cost:		
Electric	$ 13,664,168	$ 12,684,366
Gas	532,346	509,746
Other	104,790	97,214
	14,301,304	13,291,326
Less accumulated depreciation and amortization	6,535,693	6,204,367
	7,765,611	7,086,959
Construction work in progress:		
Nuclear fuel in process	96,676	117,789
Other	564,275	500,924
Total property and plant, net	8,426,562	7,705,672
Investments and other assets:		
Investments	39,432	40,235
Nuclear decommissioning trust fund	186,937	190,625
Other	113,493	97,630
Total investments and other assets	339,862	328,490
Current assets:		
Cash and cash equivalents	67,092	125,968
Accounts receivable - trade (less allowance for doubtful accounts of $8,783 and $8,028, respectively)	389,127	474,425
Other accounts and notes receivable	71,234	56,529
Materials and supplies, at average cost:		
Fossil fuel	158,800	107,572
Other	136,322	119,478
Other	40,939	37,210

Total current assets	863,514	921,182
Regulatory assets:		
Deferred income taxes	604,092	600,100
Other	166,545	158,986
Total regulatory assets	770,637	759,086
Total Assets	$ 10,400,575	$ 9,714,430
CAPITAL AND LIABILITIES		
Capitalization:		
Common stock, $.01 par value, 400,000,000 shares authorized -shares outstanding of 138,045,639 and 137,215,462, respectively (Note 5)	$1,380	$1,372
Other paid-in capital, principally premium on common stock	1,614,206	1,581,339
Retained earnings	1,733,558	1,613,960
Accumulated other comprehensive income	4,417	-
Other	(4,801)	-
Total common stockholders' equity	3,348,760	3,196,671
Preferred stock of subsidiaries not subject to mandatory redemption (Note 5)	235,197	235,197
Long-term debt (Note 7)	2,835,378	2,745,068
Total capitalization	6,419,335	6,176,936
Minority interest in consolidated subsidiaries	3,534	3,940
Current liabilities:		
Current maturity of long-term debt (Note 7)	138,961	44,444
Short-term debt	641,336	203,260
Accounts and wages payable	392,169	462,924
Accumulated deferred income taxes	57,787	49,829
Taxes accrued	132,246	124,706
Other	218,525	300,798
Total current liabilities	1,581,024	1,185,961

Commitments and contingencies (Notes 2, 11 and 12)		
Accumulated deferred income taxes	1,562,916	1,540,536
Accumulated deferred investment tax credits	157,936	164,120
Regulatory liability	172,290	183,541
Other deferred credits and liabilities	503,540	459,396
Total Capital and Liabilities	$ 10,400,575	$ 9,714,430

See Notes to Consolidated Financial Statements.

AMEREN CORPORATION
CONSOLIDATED STATEMENT OF INCOME
(Thousands of Dollars, Except Share and Per Share Amounts)

For the year ended	December 31, 2001	December 31, 2000	
OPERATING REVENUES:			
Electric	$ 4,155,240	$ 3,526,578	$
Gas	342,168	323,886	
Other	8,459	6,366	
Total operating revenues	4,505,867	3,856,830	
OPERATING EXPENSES:			
Operations:			
Fuel and purchased power	1,562,164	1,025,221	
Gas	221,842	209,467	
Other	708,096	664,544	
	2,492,102	1,899,232	
Maintenance	382,105	367,921	
Depreciation and amortization	405,804	383,110	
Income taxes	300,052	301,192	
Other taxes	260,817	265,065	
Total operating expenses	3,840,880	3,216,520	
OPERATING INCOME	664,987	640,310	
OTHER INCOME AND (DEDUCTIONS):			
Allowance for equity funds used during construction	12,893	5,298	
Miscellaneous, net	674	(4,400)	
Total other income and (deductions)	13,567	898	
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	678,554	641,208	
INTEREST CHARGES AND PREFERRED DIVIDENDS:			
Interest	198,648	179,706	
Allowance for borrowed funds used during construction	(7,925)	(8,292)	
Preferred dividends of subsidiaries	12,445	12,700	
Net interest charges and preferred dividends	203,168	184,114	
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	475,386	457,094	
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAXES	(6,841)	-	
NET INCOME	$ 468,545	$ 457,094	$
EARNINGS PER COMMON SHARE - BASIC			
Income before cumulative effect of change in accounting principle	$ 3.46	$ 3.33	$
Cumulative effect of change in accounting principle, net			

of income taxes	(.05)	-	-
EARNINGS PER COMMON SHARE - BASIC	$ 3.41	$ 3.33	$
EARNINGS PER COMMON SHARE - DILUTED			
Income before cumulative effect of change in accounting principle	$ 3.45	$ 3.33	$
Cumulative effect of change in accounting principle, net of income taxes	(.05)	-	
EARNINGS PER COMMON SHARE - DILUTED	$ 3.40	$ 3.33	$
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (Note 1)	137,320,692	137,215,462	

See Notes to Consolidated Financial Statements.

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AMEREN CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Thousands of Dollars)

For the year ended	December 31, 2001	December 31, 2000	Dec
Cash Flows From Operating:			
Net income	$ 468,545	$ 457,094	$ 3
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of change in accounting principle	6,841	-	
Depreciation and amortization	393,088	370,776	3
Amortization of nuclear fuel	29,370	37,101	
Allowance for funds used during construction	(20,818)	(13,590)	(
Deferred income taxes, net	28,018	1,699	(
Deferred investment tax credits, net	(6,184)	(6,714)	
Changes in assets and liabilities:			
Receivables, net	70,593	(139,845)	
Materials and supplies	(68,072)	26,174	
Accounts and wages payable	(70,755)	121,650	
Taxes accrued	7,540	(30,690)	
Other, net	(100,124)	31,927	
Net cash provided by operating activities	738,042	855,582	9
Cash Flows From Investing:			
Construction expenditures	(1,102,586)	(928,727)	(5
Allowance for funds used during construction	20,818	13,590	
Nuclear fuel expenditures	(24,359)	(21,527)	(
Other	803	26,241	
Net cash used in investing activities	(1,105,324)	(910,423)	(5
Cash Flows From Financing:			
Dividends on common stock	(348,819)	(348,527)	(3
Redemptions -			
Nuclear fuel lease	(64,122)	(11,356)	(

Long-term debt	(63,544)	(420,994)	(1
Issuances -			
Common stock	33,397	-	
Nuclear fuel lease	13,418	9,109	
Short-term debt	438,076	55,095	
Long-term debt	300,000	702,600	1
Net cash provided by (used in) financing activities	308,406	(14,073)	(2
Net change in cash and cash equivalents	(58,876)	(68,914)	1
Cash and cash equivalents at beginning of year	125,968	194,882	
Cash and cash equivalents at end of year	$ 67,092	$ 125,968	$ 1
Cash paid during the periods:			
Interest (net of amount capitalized)	$ 187,121	$ 168,650	$ 16
Income taxes	266,352	311,848	24

See Notes to Consolidated Financial Statements.

AMEREN CORPORATION
CONSOLIDATED STATEMENT OF COMMON STOCKHOLDERS' EQUITY
(Thousands of Dollars)

For the year ended	December 31, 2001	December 31, 2000	Decemb 199
Common stock			
Beginning balance	$ 1,372	$ 1,372	$ 1,
Shares issued	8	-	-
	1,380	1,372	1,
Other paid-in capital			
Beginning balance	1,581,339	1,582,501	1,582,
Shares issued	33,389	-	-
Employee stock awards	(522)	(1,162)	
	1,614,206	1,581,339	1,582,
Retained earnings			
Beginning balance	1,613,960	1,505,827	1,472,
Net income	468,545	457,094	385,
Dividends	(348,947)	(348,961)	(351,
	1,733,558	1,613,960	1,505,
Accumulated other comprehensive income			
Beginning balance	-	-	-
Change in current period	4,417	-	-
	4,417	-	-

Other			
Beginning balance	-	-	-
Unamortized restricted stock compensation	(5,704)	-	-
Compensation amortized and mark-to-market adjustments	903	-	-
	(4,801)	-	-
Total common stockholders' equity	$ 3,348,760	$ 3,196,671	$ 3,089,
Comprehensive income, net of taxes			
Net income	$ 468,545	457,094	385,
Cumulative effect of accounting change	(11,258)	-	-
Unrealized net gain on derivative hedging instruments	15,675	-	-
	$ 472,962	$ 457,094	$ 385,

See Notes to Consolidated Financial Statements.

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AMEREN CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001

NOTE 1 - Summary of Significant Accounting Policies

Basis of Presentation
Ameren Corporation (Ameren or the Company) 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 outstanding preferred shares of AmerenUE and AmerenCIPS were not affected by the Merger.

The accompanying consolidated financial statements include the accounts of Ameren and its 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, AmerenCIPS, and AmerenEnergy Generating Company (Generating Company), a wholly-owned subsidiary of AmerenEnergy Resources Company (Resources Company), 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 other principal subsidiaries include: CIC, an investing subsidiary; AmerenEnergy, Inc., an energy trading and marketing subsidiary; Ameren Development Company, a nonregulated products and services subsidiary; Resources Company, a holding company for the Company's nonregulated generating operations; and Ameren Services Company, a shared support services subsidiary. The Company also has a 60% interest in Electric Energy, Inc. (EEI). EEI owns and/or operates electric generation and transmission facilities in Illinois that supply 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.

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 among their different business activities.

Regulation

Ameren is subject to regulation by the Securities and Exchange Commission (SEC). Certain of Ameren's subsidiaries are also regulated by the Missouri Public Service Commission (MoPSC), Illinois Commerce Commission (ICC), Nuclear Regulatory Commission (NRC) and the Federal Energy Regulatory Commission (FERC). 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 2001, 2000, and 1999 was approximately 3% of the average depreciable cost.

Fuel and Gas Costs

In the Company's retail electric utility jurisdictions, the cost of fuel for electric generation is reflected in base rates with no provision for changes in such cost to be reflected in billings to customers through fuel adjustment clauses. In the Company's retail gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through purchased gas adjustment clauses.

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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 4% - 10% during 2001, 6% - 10% during 2000, and 5% - 10% during 1999.

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
Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," became effective on January 1, 2001. 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 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 stockholders' equity. See Note 3 - Risk Management and Derivative Financial Instruments for further information.

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 non-trading. Furthermore, transactions that are determined to be trading activities would be recognized on the balance sheet measured at fair value, with changes in fair market value included in earnings.

AmerenEnergy, Inc. enters into contracts, some of which are derivatives, for the sale and purchase of energy on behalf of AmerenUE and Generating Company. Derivatives are accounted for under SFAS 133 or EITF 98-10 based on the Company's intent when entering into the contract. Virtually all non-derivative contracts are accounted for using the accrual or settlement method.

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.

Evaluation of Assets for Impairment
SFAS 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, 2001, no impairment was identified.

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS 121. SFAS 144 retains the guidance related to calculating and recording impairment losses, but adds guidance on the accounting for discontinued operations, previously accounted for under Accounting Principles Board Opinion No. 30. SFAS 144 was adopted by the Company on January 1, 2002, and did not have a material effect on the Company's financial position, results of operations or liquidity.

Asset Retirement Obligations

In July 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires an entity to record a liability and corresponding asset representing the present value of legal obligations associated with the retirement of tangible, long-lived assets. SFAS 143 is effective for fiscal years beginning after June 15, 2002. At this time, the Company is assessing the impact of SFAS 143 on its financial position, results of operations and liquidity upon adoption. However, SFAS 143 is expected to result in significant increases to the Company's reported assets and liabilities as a result of its ongoing collection through rates of and obligations associated with Callaway Nuclear Plant decommissioning costs. See Note 12 - Callaway Nuclear Plant for further information.

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 10 - Stock-Based Compensation for further information.

Earnings Per Share

The Company's calculation of diluted earnings per share resulted in dilution of $.01 for 2001. There was no difference between the basic and diluted earnings per share amounts in 2000 and 1999. 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 331,813 shares, 183,201 shares, and 38,786 shares in 2001, 2000 and 1999, 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.

New Accounting Pronouncements

In July 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS 141 requires business combinations to be accounted for under the purchase method of accounting, which requires one party in the transaction to be identified as the acquiring enterprise and for that party to allocate the purchase price to the assets and

liabilities of the acquired enterprise based on fair market value. It prohibits use of the pooling-of-interests method of accounting for business combinations.

SFAS 141 is effective for all business combinations initiated after June 30, 2001, or transactions completed using the purchase method after June 30, 2001. SFAS 142 requires goodwill recorded in the financial statements to be tested for impairment at least annually, rather than amortized over a fixed period, with impairment losses recorded in the income statement. SFAS 142 became effective for the Company on January 1, 2002. SFAS 141 and SFAS 142 did not have a material effect on the Company's financial position, results of operations or liquidity upon adoption.

Reclassifications

Certain reclassifications have been made to prior years' financial statements to conform with 2001 reporting.

NOTE 2 - Regulatory Matters

Missouri Electric

In July 1995, the MoPSC approved an agreement establishing contractual obligations involving AmerenUE'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.

The MoPSC staff proposed adjustments to AmerenUE's estimated customer credit of $43 million for the final year of the Original Plan ended June 30, 1998, which were the subject of regulatory proceedings before the MoPSC in 1999. In December 1999, the MoPSC issued a Report and Order (Order) concerning these proposed adjustments. Based on the provisions of that Order, AmerenUE revised its estimated final year credit of the Original Plan to $31 million in the quarter ended December 31, 1999. Subsequently, AmerenUE filed a request for rehearing of the Order with the MoPSC, asking that it reconsider its decision to adopt certain of the MoPSC staff's adjustments. The request was denied by the MoPSC and in February 2000, AmerenUE filed a Petition for Writ of Review with the Circuit Court of Cole County, Missouri, requesting that the Order be reversed. The appeal is pending and the ultimate outcome cannot be predicted; however, the final decision is not expected to materially impact the financial condition, results of operations or liquidity of the Company. A partial stay of the Order was granted by the Court pending the appeal.

A new three-year experimental alternative regulation plan (the New Plan) was included in the joint agreement authorized by the MoPSC in its February 1997 order approving the Merger. Like the Original Plan, the New Plan required an earnings over a 12.61% ROE up to a 14% ROE be shared equally between customers and stockholders. The New Plan also returned to customers 90% of all earnings above a 14% ROE up to a 16% ROE. Earnings above a 16% ROE were credited entirely to customers. The New Plan ran from July 1, 1998 through June 30, 2001. In May 2001, the MoPSC approved a stipulation and agreement of the parties regarding the credit for the plan year ended June 30, 2000 of $28 million, which was paid. At December 31, 2001, the Company recorded an estimated credit that AmerenUE expects to pay its Missouri electric customers of $40 million for the plan year ended June 30, 2001. During the year ended December 31, 2001, the Company reduced the estimated credit previously recorded for the plan year ended June 30, 2001 by $10 million, compared to estimated credits of $65 million recorded in the year ago period for plan years ended June 30, 2001 and 2000. These credits were reflected as a reduction in electric revenues. The final amount of the 2001 credit will depend on several factors, including approval by the MoPSC.

With the New Plan's expiration on June 30, 2001, on July 2, 2001, the MoPSC staff filed with the MoPSC an excess earnings complaint against AmerenUE that proposed to reduce its annual electric revenues ranging from $213 million to

$250 million. Factors contributing to the MoPSC staff's recommendation included return on equity (ROE), revenues and customer growth, depreciation rates and other cost of service expenses. The ROE incorporated into the MoPSC staff's recommendation ranged from 9.04% to 10.04%. The MoPSC is not bound by the MoPSC staff's recommendation. In January 2002, the MoPSC issued an order that established the test year to be used to determine rates as July 1, 2000 through June 30, 2001, with updates to that test year permitted through September 30, 2001. The MoPSC staff had utilized a test year of July 1, 1999 through June 30, 2000 in its original complaint. In addition, the MoPSC order stated that AmerenUE would be permitted to propose an incentive regulation plan in this proceeding.

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The MoPSC order also included a revised procedural schedule to allow all parties additional time to review data and file testimony, due to the utilization of a more current test year. Under the new schedule, the MoPSC staff will file direct testimony on March 1, 2002, with AmerenUE and the Office of Public Counsel filing rebuttal testimony on May 10, 2002. Evidentiary hearings on the MoPSC staff's recommendation are scheduled to be conducted before the MoPSC beginning in July 2002. In the event that the MoPSC ultimately determines that a rate decrease is warranted in this case, that rate reduction would be retroactive to April 1, 2002, regardless of when the MoPSC issues its decision. A final decision on this matter may not occur until the fourth quarter of 2002. Depending on the outcome of the MoPSC's decision, further appeals in the courts may be warranted.

In the interim, the Company expects to continue negotiations with all pertinent parties with the intent to continue with an incentive regulation plan, similar in form to the New Plan. The Company cannot predict the outcome of these negotiations and their impact on the Company's financial position, results of operations or liquidity; however, the impact could be material.

Gas
In October 2000, the MoPSC approved a $4 million annual rate increase for natural gas service in AmerenUE's Missouri jurisdiction. The rate increase became effective November 1, 2000. 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.

Midwest ISO and Alliance RTO
In 1998, AmerenUE and AmerenCIPS joined a group of companies that originally supported 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 facilitating wholesale and retail competition through the elimination of "pancaked" transmission rates. The Midwest ISO is regulated by the FERC. The FERC conditionally approved the formation of the Midwest ISO in September 1998.

In December 1999, the FERC issued Order 2000 relating to Regional Transmission Organizations (RTOs) that would meet certain characteristics such as size and independence. RTOs, including ISOs, are entities that ensure comparable and non-discriminatory access to regional electric transmission systems. Order 2000 calls on all transmission owners to join RTOs.

In the fourth quarter of 2000, the Company announced its intention to withdraw from the Midwest ISO and to join the Alliance RTO, and recorded a pretax charge to earnings of $25 million ($15 million after taxes, or 11 cents per share), which related to the Company's estimated obligation under the Midwest ISO agreement for costs incurred by the Midwest ISO, plus estimated exit costs. In

2001, the Company announced that it had signed an agreement to join the Alliance RTO. In a proceeding before the FERC, the Alliance RTO and the Midwest ISO reached an agreement that would enable Ameren to withdraw from the Midwest ISO and to join the Alliance RTO. This settlement agreement was approved by the FERC. The Company's withdrawal from the Midwest ISO remains subject to MoPSC approval. In July 2001, the FERC conditionally approved the formation, including the rate structure, of the Alliance RTO. However, on December 20, 2001, the FERC issued an order that reversed its position and rejected the formation of the Alliance RTO. Instead, the FERC granted RTO status to the Midwest ISO and ordered the Alliance RTO Companies and the Midwest ISO to discuss how the Alliance RTO business model could be accommodated within the Midwest ISO. The Alliance RTO members have until February 19, 2002 to respond to the FERC's December 2001 order. At this time, the Company is evaluating its alternatives, including the possible appeal of the FERC's December 2001 order, and is unable to determine the impact that the FERC's latest ruling will have on its future financial condition, results of operations or liquidity.

Illinois Electric Restructuring and Related Matters
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 occurred 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. In August 1999, the ICC issued an order approving the delivery service tariffs, with an allowed rate of return on equity of 10.45%. In December 2000, AmerenUE and AmerenCIPS filed revised Illinois delivery service tariffs with the ICC. The purpose of the filing was to update financial information that was used to establish the initial rates and to propose new rates. Additionally, the filing establishes tariffs for residential customers who may choose to purchase their power from alternate suppliers beginning in May 2002. In December 2001, the ICC issued an Order approving the delivery service tariffs, with an allowed rate of return on equity of 11.35%.

Under the Illinois Law, the Company is subject to a residential electric rate decrease of up to 5% in 2002, to the extent its rates exceed the Midwest utility average at that time. In 2001, the Company's Illinois electric rates were below the Midwest utility average.

The Illinois Law also contains a provision requiring that one-half of excess earnings from the Illinois jurisdiction for the years 1998 through 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 U.S. 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. The Company did not record any estimated refunds to Illinois customers in 2001.

In conjunction with another provision of the Illinois Law, on May 1, 2000, following the receipt of all required state and federal regulatory approvals, AmerenCIPS transferred its electric generating assets and liabilities, at historical net book value, to Generating Company, in exchange for a promissory note from Generating Company in the principal amount of approximately $552 million and Generating Company common stock (the Transfer). The promissory note bears interest at 7% and has a term of five years payable based on a 10-year amortization. The transferred assets represent a generating capacity of approximately 2,900 megawatts. Approximately 45% of AmerenCIPS' employees were transferred to Generating Company as part of the transaction.

In conjunction with the Transfer, an electric power supply agreement was entered into between Generating Company and its newly created nonregulated affiliate, AmerenEnergy Marketing Company (Marketing Company), also a wholly-owned subsidiary of Resources Company. Under this agreement, Marketing Company is entitled to purchase all of the Generating Company's energy and capacity. This agreement may not be terminated until at least December 31, 2004. In addition, Marketing Company entered into an electric power supply agreement with AmerenCIPS to supply it sufficient energy and capacity to meet its obligations as a public utility. This agreement expires December 31, 2004. Power will continue to be jointly dispatched between AmerenUE and Generating Company.

The creation of the new subsidiaries and the transfer of AmerenCIPS' generating assets and liabilities had no effect on the consolidated financial statements of Ameren as of the date of the Transfer.

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 wholesale customers and those retail customers in Illinois who choose other suppliers as allowed under the Illinois Law. In January 2000, the Company and other parties to the rate case entered into a settlement agreement resolving all issues pending before the FERC. In May 2000, the FERC approved the settlement and allowed the settlement rates to become effective as of the first quarter of 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 70% of the Company's retail electric revenues are derived, restructuring bills have been introduced but no legislation has been passed. Furthermore, no restructuring legislation is expected to be passed by the Missouri state legislature in 2002. 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, 2001, the Company's net investment in generation facilities related to its Missouri jurisdiction approximated $2.8 billion and was included in electric plant in-service on the Company's balance sheet. In addition, at December 31, 2001, the Company's Missouri net generation-related regulatory assets approximated $449 million.

Regulatory Assets and Liabilities

In accordance with SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation," 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	2001	2000
Regulatory Assets:		
Income taxes (a)	$604	$600
Callaway costs (b)	84	88
Unamortized loss on reacquired debt(c)	28	31
Recoverable costs - contaminated facilities (d)	26	6
Merger costs (e)	12	17
Other	17	17
Regulatory Assets	$771	$759
Regulatory Liability:		
Income taxes	$172	$184
Regulatory Liability	$172	$184

(a) See Note 8 - Income Taxes.
(b) Represents Callaway Nuclear Plant operations and maintenance expenses, property taxes and carrying costs incurred between the plant in-service date and the date the plant was reflected in rates. These costs are being amortized over the remaining life of the plant (through 2024).
(c) Represents losses related to refunded debt. These amounts are being amortized over the lives of the related new debt issues or the remaining lives of the old debt issues if no new debt was issued.
(d) Represents the recoverable portion of accrued environmental site liabilities.
(e) 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 - Risk Management and Derivative Financial Instruments

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

Market Risk

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

Credit Risk

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

The Company's physical and financial instruments are subject to credit risk consisting of trade accounts receivables and executory contracts with market risk exposures. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising the Company's customer base. No customer represents greater than 10% of the Company's accounts receivable. The Company's revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. The Company analyzes each counterparty's financial condition prior to entering into forwards, swaps, futures or option contracts. The Company also establishes credit limits for these counterparties and monitors the appropriateness of these limits on an ongoing basis through a credit risk management program which involves daily exposure reporting to senior management, master trading and netting agreements, and credit support management (e.g., letters of credit and parental guarantees).

Derivative Financial Instruments

In January 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The impact of that adoption resulted in the Company recording a cumulative effect charge of $7 million after taxes to the income statement, and a cumulative effect adjustment of $11 million after income taxes to Accumulated Other Comprehensive Income (OCI), which reduced stockholders' equity. In June 2001, the Derivatives Implementation Group (DIG), a committee of the FASB responsible for providing guidance on the implementation of SFAS 133, reached a conclusion regarding the appropriate accounting treatment of certain types of energy contracts under SFAS 133. Specifically, the DIG concluded that power purchase or sales agreements (both forward contracts and option contracts) may be accounted for as normal purchases and sales if certain criteria are met. This guidance was effective beginning July 1, 2001, and did not have a material impact on the Company's financial condition, results of operations or liquidity. However, in October and again in December 2001, the DIG revised this guidance, with the revisions generally effective April 1, 2002. The Company does not expect the impact of the DIG's revisions to have a material effect on the Company's financial condition, results of operations, or liquidity upon adoption.

SFAS 133 requires all derivatives to be recognized on the balance sheet at their fair value. On the date that the Company enters into a derivative contract, it designates the derivative as (1) a hedge of the fair value of a recognized asset or liability or an unrecognized firm commitment (a "fair value" hedge); (2) a hedge of a forecasted transaction or the variability of cash flows that are to be received or paid in connection with a recognized asset or liability (a "cash flow" hedge); or (3) an instrument that is held for trading or non-hedging purposes (a "non-hedging" instrument). The Company reevaluates its classification of individual derivative transactions daily.

Changes in the fair value of derivatives are recorded each period in current earnings or OCI, depending on whether a derivative is designated as part of a hedge transaction and, if it is, the type of hedge transaction. For fair-value hedge transactions, changes in the fair value of the derivative instrument are offset in the income statement by changes in the hedged item's fair value. For cash-flow hedge transactions, changes in the fair value of the derivative instrument are reported in OCI. The gains and losses on the derivative instrument that are reported in OCI will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges is recognized in current-period earnings.

The Company utilizes derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause (1) an unrealized appreciation or depreciation of the Company's firm commitments to purchase or sell when purchase or sales prices under the firm commitment are compared with current commodity prices; (2) market values of fuel and natural gas inventories or purchased power to differ from the cost of those commodities under the firm commitment; and (3) actual cash outlays for the purchase of these commodities to differ from anticipated cash outlays. The derivatives that the Company uses to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. Ameren primarily uses derivatives to optimize the value of its physical and contractual positions. Ameren continually assesses its supply and delivery commitment positions against forward market prices and internally forecasts forward prices and modifies its exposure to market, credit and operational risk by entering into various offsetting transactions. In general, these transactions serve to reduce price risk for the Company.

As of December 31, 2001, the Company has recorded the fair value of derivative financial instrument assets of $17 million in Other Assets and the fair value of derivative financial instrument liabilities of $18 million in Other Deferred Credits and Liabilities.

Cash Flow Hedges

The Company routinely enters into forward purchase and sales contracts for electricity based on forecasted levels of economic generation and load requirements. The relative balance between load and economic generation varies throughout the year. The contracts typically cover a period of twelve months or less. The purpose of these contracts is to hedge against possible price fluctuations in the spot market for the period covered under the contracts. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions.

As of December 31, 2001, a gain of $7 million ($4.3 million, after tax) associated with interest rate swaps for debt to be issued was in OCI and will be amortized over the life of the debt ultimately issued or will be recognized immediately to the income statement if a determination is made that debt will not be issued.

For the year ended December 31, 2001, the pretax net gain, which represented the impact of discontinued cash flow hedges, the ineffective portion of cash flow hedges, as well as the reversal of amounts previously recorded in OCI due to transactions going to delivery, was approximately $15 million.

As of December 31, 2001, the entire net gain on derivative instruments accumulated in OCI is expected to be recognized in earnings during the next twelve months upon delivery of the commodity being hedged.

Other Derivatives

The Company enters into option transactions to manage the Company's positions in sulfur dioxide (SO_2) allowances, coal, heating oil, and electricity. These transactions are treated as non-hedge transactions under SFAS 133. The net change in the market value of SO_2 options is recorded as electric revenues, while the net change in the market value of coal, heating oil, and electricity options is recorded as fuel and purchased power in the income statement.

The Company has entered into fixed-price forward contracts for the purchase of fuel. While these contracts meet the definition of a derivative under SFAS 133, the Company records these transactions as normal purchases and normal sales because the contracts are expected to result in physical delivery. In September 2001, the DIG issued guidance regarding the accounting treatment for fuel

contracts that combine a forward contract and a purchased option contract. The DIG concluded that contracts containing both a forward contract and a purchased option contract that extends the quantity to be purchased at a fixed price are not eligible to qualify for the normal purchases and sales exception under SFAS 133. This guidance is effective as of April 1, 2002. The Company continues to evaluate the impact of this guidance on its future financial condition, results of operations or liquidity; however, the impact is not expected to be material.

NOTE 4 - Nuclear Fuel Lease

The Company has a lease agreement that provides for the financing of a portion of its nuclear fuel. At December 31, 2001, 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 expenditures for nuclear fuel, interest and related costs under the lease. Obligations under this lease become due as any leased nuclear fuel is consumed at the Company's Callaway Nuclear Plant. No leased nuclear fuel was consumed in 2001. The Company reimbursed the lessor $13 million in 2000 and $16 million during 1999 for amounts consumed under the lease.

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 $4 million in 2001, $8 million in 2000, and $5 million in 1999. Interest charges for these years were based on average interest rates of approximately 5% for 2001 and 7% for 2000 and 1999. Interest charges of $4 million in 2001, $6 million in 2000, and $4 million in 1999 were capitalized.

NOTE 5 - 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, 2001 and 2000, AmerenUE and AmerenCIPS had 25 million shares and 4.6 million shares respectively, of authorized preferred stock.

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

Preferred Stock of Subsidiaries Not Subject to Mandatory Redemption:

Dollars in Millions at December 31,

	Redemption Price (per share)	2001	2000
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 OF SUBSIDIARIES 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 2001 was 3.63%.

NOTE 6 - Short-Term Borrowings

Short-term borrowings of the Company consist of bank loans and commercial paper (maturities generally within 1-45 days). At December 31, 2001 and 2000, $641 million and $203 million, respectively, of short-term borrowings were outstanding. The weighted average interest rates on short-term borrowings outstanding at December 31, 2001 and 2000, were 1.9% and 6.7%, respectively.

At December 31, 2001, the Company had committed bank lines of credit, aggregating $156 million, all of which were unused and available at such date. These lines 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 also has bank credit agreements totaling $700 million, expiring at various dates between 2002 and 2003, that support the Company's commercial paper programs. At December 31, 2001, all of the bank credit agreements were unused; however, due to commercial paper borrowings and other commitments, $126 million of such borrowing capacity was available.

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The Company has money pool agreements with and 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 7 - Long-Term Debt

Long-term debt outstanding at December 31,	2001	2000
In Millions		
First Mortgage Bonds - note (a)		
8.33% Series due 2002	$75	$75
6 3/8% Series Z due 2003	40	40
7.65% Series due 2003	100	100
6 7/8% Series due 2004	188	188
7 3/8% Series due 2004	85	85
7 1/2% Series X due 2007	50	50
6 3/4% Series due 2008	148	148
6.625% Series due 2011	150	-
7.61% 1997 Series due 2017	40	40
8 3/4% Series due 2021	125	125
8 1/4% 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 2002 through 2008	93	123

	1,562	1,442
Environmental Improvement/Pollution Control Revenue Bonds		
1991 Series due 2020 - note (c)	43	43
1992 Series due 2022 - note (c)	47	47
1993 Series A 6 3/8% due 2028	35	35
1993 Series C-1 5.95% due 2026 (h)	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
2000 Series A 5.5% due 2014 (h)	51	51
2000 Series A due 2035 - note (c)	64	64
2000 Series B due 2035 - note (c)	63	63
2000 Series C due 2035 - note (c)	60	60
Other 5%-5.90% due 2026 through 2028	60	60
	618	618
Subordinated Deferrable Interest Debentures		
7.69% Series A due 2036 - note (d)	66	66
Unsecured Loans		
Commercial Paper	-	19
1991 Senior Medium Term Notes 8.60% due through 2005	27	33
1994 Senior Medium Term Notes 6.61% due through 2005	31	39
2000 Senior Notes 7.61% due 2004	40	40
2000 Senior Notes Series C 7 3/4% due 2005 - note (e)	225	225
2000 Senior Notes Series D 8.35% due 2010 - note (f)	200	200
2001 Floating Rate Notes due 2003 - note (g)	150	-
	673	556
Nuclear Fuel Lease	63	114
Unamortized Discount and Premium on Debt	(8)	(7)
Maturities Due Within One Year	(139)	(44)
Total Long-Term Debt	$2,835	$2,745

(a) At December 31, 2001, a majority 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 2001 are as follows: 1991 Series 3.15%

1992 Series	3.11%
1998 Series A	3.07%
1998 Series B	3.07%
1998 Series C	3.04%
2000 Series A	2.99%
2000 Series B	2.97%
2000 Series C	3.03%

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

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

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

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

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

Maturities of long-term debt through 2006 are as follows:

(In Millions)	Principal Amount
2002	$139
2003	340
2004	344
2005	259
2006	20

In January 2002, Ameren Corporation issued 5.70% Notes totaling $100 million. Interest is payable semi-annually on February 1 and August 1 of each year, beginning August 1, 2002, and on the date of maturity, February 1, 2007. Ameren Corporation received net proceeds of $99.1 million after a discount to the public and deduction of underwriters' commissions. With the proceeds, Ameren Corporation reduced its short-term borrowings.

The Company anticipates securing additional financing in 2002. In January 2002, Ameren Corporation filed a shelf registration statement with the SEC on Form S-3 which, upon its effective date, will allow the offering from time to time of various forms of debt and equity securities, up to an aggregate offering price of $1 billion. The proceeds from any sale of such securities may be used to finance the Company's subsidiaries' ongoing construction and maintenance programs, to redeem, repurchase, repay or retire outstanding indebtedness, including indebtedness of the Company's subsidiaries, to finance strategic investments in or future acquisitions of other entities or other assets and for other general corporate purposes. At this time, the Company is unable to determine the amount of the additional financing, as well as the additional financing's impact on the Company's financial position, results of operations or liquidity.

NOTE 8 - Income Taxes

Total income tax expense for 2001 resulted in an effective tax rate of 39% on earnings before income taxes (39% in 2000 and 1999).

Principal reasons such rates differ from the statutory federal rate:

	2001	2000	1999
Statutory federal income tax rate:	35%	35%	35%
Increases (Decreases) from:			
Depreciation differences	2	2	1
State tax	3	3	4
Other	(1)	(1)	(1)

Effective income tax rate	39%	39%	39%

Income tax expense components:

In Millions	2001	2000	1999
Taxes currently payable (principally Federal):			
Included in operating expenses	$ 280	$ 307	$ 287
Included in other income--			
Miscellaneous, net	6	(2)	(3)
	286	305	284
Deferred taxes (principally federal):			
Included in operating expenses--			
Depreciation differences	9	(5)	3
Other	19	7	(23)
Included in other income--			
Other	-	-	(2)
	28	2	(22)
Deferred investment tax credits, Amortization:			
Included in operating expenses	(8)	(8)	(8)
Total income tax expense	$ 306	$ 299	$ 254

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	2001	2000
Accumulated Deferred Income Taxes:		
Depreciation	$1,040	$1,043
Regulatory assets, net	434	417
Capitalized taxes and expenses	184	181
Deferred benefit costs	(68)	(73)
Other	31	22

Total net accumulated deferred income tax liabilities	$1,621	$1,590

NOTE 9 - Retirement Benefits

The Company has defined benefit retirement plans covering substantially all employees of AmerenUE, AmerenCIPS, and Ameren Services Company and certain employees of Resources Company and its subsidiaries. Benefits are based on the employees' years of service and compensation. The Company's plans are funded in compliance with income tax regulations and federal funding requirements.

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

Funded Status of Ameren's Pension Plans:

In Millions	2001	2000
Change in benefit obligation		
Net benefit obligation at beginning of year	$ 1,362	$1,257
Service cost	32	30
Interest cost	100	98
Plan amendments	-	28
Actuarial loss	14	38
Benefits paid	(90)	(89)
Net benefit obligation at end of year	1,418	1,362
Change in plan assets *		
Fair value of plan assets at beginning of year	1,359	1,427
Actual return on plan assets	45	(20)
Employer contributions	1	1
Benefits paid	(90)	(89)
Fair value of plan assets at end of year	1,225	1,359
Funded status - deficiency/(excess)	193	3
Unrecognized net actuarial gain/(loss)	(33)	160
Unrecognized prior service cost	(77)	(82)
Unrecognized net transition asset	5	6
Accrued pension cost at December 31	$ 88	$ 87

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

Components of Ameren's Net Periodic Pension Benefit Cost:

In Millions	2001	2000	1999
Service cost	$ 32	$ 30	$ 33
Interest cost	100	98	91

Expected return on plan assets	(115)	(110)	(104)
Amortization of:			
Transition asset	(1)	(1)	(1)
Prior service cost	9	7	7
Actuarial gain	(21)	(2)	(21)
Net periodic benefit cost	$ 4	$ 3	$ 24

Weighted-average Assumptions for Actuarial Present Value of Projected Benefit Obligations:

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

On January 1, 2000, the AmerenUE and the AmerenCIPS postretirement benefit plans combined to form the Ameren Plans. The Ameren Plans cover substantially all employees of AmerenUE, AmerenCIPS, and Ameren Services Company and certain employees of Resources Company and its subsidiaries. The AmerenUE and AmerenCIPS postretirement plans' information for 1999 is presented separately. Following is the postretirement plan information related to Ameren's plans as of December 31.

Ameren's funding policy is to annually fund the Voluntary Employee Beneficiary Association trusts (VEBA) with the lesser of the net periodic cost or the amount deductible for federal income tax purposes. Postretirement benefit costs were $63 million and $58 million for 2001 and 2000, respectively, of which approximately 18% and 17%, respectively were charged to construction accounts. Ameren's transition obligation at December 31, 2001 is being amortized over the next 12 years.

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

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Funded Status of Ameren's Postretirement Benefit Plans:

In Millions	2001	2000
Change in benefit obligation		
Net benefit obligation at beginning of year	$ 589	$ 492
Service cost	23	20
Interest cost	47	43
Plan amendments	-	(26)
Actuarial loss	80	94
Benefits paid	(38)	(34)
Net benefit obligation at end of year	701	589
Change in plan assets *		
Fair value of plan assets at beginning of year	290	269
Actual return on plan assets	(17)	(4)
Employer contributions	65	59
Benefits paid	(38)	(34)

Fair value of plan assets at end of year	300	290
Funded status - deficiency	401	299
Unrecognized net actuarial gain	(134)	(14)
Unrecognized prior service cost	2	2
Unrecognized net transition obligation	(180)	(196)
Postretirement benefit liability at December 31	$ 89	$ 91

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

Components of Ameren's Net Periodic Postretirement Benefit Cost:

In Millions	2001	2000
Service cost	$ 23	$ 19
Interest cost	47	43
Expected return on plan assets	(25)	(18)
Amortization of:		
Transition obligation	16	16
Actuarial (gain)/loss	2	(2)
Net periodic benefit cost	$ 63	$ 58

Assumptions for the Obligation Measurements:

	2001	2000
Discount rate at measurement date	7.25%	7.50%
Expected return on plan assets	8.50%	8.50%
Medical cost trend rate	5.25%	5.00%

A 1% increase in the medical cost trend rate is estimated to increase the net periodic cost and the accumulated postretirement benefit obligation approximately $7 million and $55 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 $7 million and $51 million, respectively.

AmerenUE's plans cover substantially all employees of AmerenUE as well as certain employees of Ameren Services Company. Postretirement benefit costs were $46 million for 1999, of which approximately 18% was charged to construction accounts.

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Components of AmerenUE's Net Periodic Postretirement Benefit Cost:

In Millions	1999
Service cost	$15
Interest cost	25
Expected return on plan assets	(6)

Amortization of transition obligation	12
Net periodic benefit cost	$46

AmerenCIPS' plans cover substantially all employees of AmerenCIPS as well as certain employees of Ameren Services Company. Postretirement benefit costs were $3 million for 1999, of which approximately 10% was charged to construction accounts.

Components of AmerenCIPS' Net Periodic Postretirement Benefit Cost:

In Millions	1999
Service cost	$3
Interest cost	9
Expected return on plan assets	(9)
Amortization of:	
Transition obligation	6
Actuarial gain	(6)
Net periodic benefit cost	$3

NOTE 10 - Stock-Based Compensation

The Company has a long-term incentive plan (the Plan) for eligible employees, which provides for the grant of options, performance awards, restricted stock, dividend equivalents and stock appreciation rights. The Company applies APB 25 in accounting for its stock-based compensation. The Company has adopted the disclosure-only method of fair value data under SFAS 123, "Accounting for Stock-Based Compensation."

Under the Plan, 141,788 restricted shares of the Company's stock were granted at $39.60 in 2001. Upon the achievement of certain Company performance levels, the restricted stock award vests over a period of seven years, beginning at the date of grant, and include provisions requiring certain stock ownership levels. An accelerated vesting provision is also included in the Plan, which reduces the vesting period from seven years to three years. The Company records unearned compensation (as a component of stockholders' equity) equal to the market value of the restricted stock on the date of grant and charges the unearned compensation to expense over the vesting period. In accordance with APB 25 and under SFAS 123, the Company's compensation expense relating to restricted stock awards totaled $903,000 in 2001.

Also 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 2010. 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 expense has been recognized for the Company's stock options. If the fair value method set forth under SFAS 123 had been used to account for options, the effects on net income and earnings would have been immaterial.

The following table summarizes stock option activity during 2001, 2000 and 1999:

	2001		2000		
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Sh
Outstanding at beginning of year	2,430,532	$35.38	1,834,108	$38.22	1,0
Granted	-	-	957,100	31.00	7
Exercised	106,416	38.31	295,693	38.41	
Cancelled or expired	83,009	35.77	64,983	37.38	
Outstanding at end of year	2,241,107	$35.23	2,430,532	$35.38	1,8
Exercisable at end of year	572,092	$38.74	312,736	$39.58	3

Additional information about stock options outstanding at December 31, 2001:

Exercise Price	Outstanding Shares	Weighted Average Life (Years)	Exercisable Shares
$31.00	908,500	8.1	8,000
35.50	800	3.6	800
35.875	35,880	3.3	35,880
36.625	633,050	7.0	148,550
38.50	102,985	5.1	71,170
39.25	464,616	6.2	215,066
39.8125	5,300	6.5	2,650
43.00	89,976	3.8	89,976

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

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

NOTE 11 - Commitments and Contingencies

The Company is engaged in a capital program under which expenditures of apprxomately $3.5 billion, including AFC and capitalized interest, are anticipated over the next five years. This estimate includes capital expenditures for the purchase of new combustion turbine generating facilities and for the replacement of four steam generators at its Callaway Nuclear Plant. In addition, this estimate includes capital expenditures for transmission, distribution and other generation related activities, as well as for compliance with new NOx control regulations, as discussed later in this Note. Commitments have been made with regard to certain of these capital expenditures.

The Company has committed to purchase combustion turbine generator equipment, which will add nearly 1,400 megawatts to its net peaking capacity and are expected to cost approximately $630 million. The Company plans to add 710 megawatts (approximately 470 megawatts at Resources Company and 240 megawatts at AmerenUE) of combustion turbine generating capacity during 2002. Total costs expected to be incurred for these combustion turbine generating units approximate $340 million. Due to expected increased demand, and the need to

maintain appropriate reserve margins, the Company believes it will need additional regulated generating capacity in the future. In 2002, AmerenUE expects to purchase up to 500 megawatts of capacity for the summer. Additional future resource options under consideration by the Company include the transfer of AmerenUE's Illinois-based electric and gas business to AmerenCIPS. Other alternatives include the addition of 650 megawatts of combustion turbine generating units. These units are estimated to cost $280 million and would be added subsequent to 2004. As of December 31, 2001, the Company had noncancelable reservation commitments of $22 million related to the potential purchase of these units. The Company continually reviews its genertion portfolio and expected electrical neeeds, and as result, could modify its plan for generation asset purchases, which could include the timing of when certain assets will be added to, or removed from its portfolio, whether the generation will be added to the regulated or nonregulated portfolio, the type of generation asset technology that will be employed, or whether capacity may be purchased, among other things. Changes to the Company's plans for future generating needs could result in losses being incurred by the Company, which could be material.

The Company has commitments for the purchase of coal under long-term contracts. Coal contract commitments, including transportation costs, for 2002 through 2006 are estimated to total $2.0 billion. Total coal purchases, including transportation costs, for 2001, 2000 and 1999 were $562 million, $507 million, and $603 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 2002 through 2006 are estimated to total $253 million. Total delivered natural gas costs were $222 million for 2001, $209 million for 2000, and $131 million for 1999. The Company's nuclear fuel commitments for 2002 through 2006, including uranium concentrates, conversion, enrichment and fabrication, are expected to total $76 million, and are expected to be substantially financed under the nuclear fuel lease. Nuclear fuel expenditures were $24 million for 2001, and $22 million in each of the years 2000 and 1999. Additionally, the Company has long-term contracts with other utilities to purchase electric capacity. These commitments for 2002 through 2006 are estimated to total $301 million. During 2001, 2000 and 1999, electric capacity purchases were $31 million, $40 million, and $44 million, respectively.

In 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 an unusual charge in the fourth quarter of 1999, equivalent to $31 million, after income taxes, or 23 cents per share.

The Company's insurance coverage for Callaway Nuclear Plant at December 31, 2001, 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)	$ 23	
Replacement Power:				
Nuclear Electric Insurance Ltd.	$ 490	(e)	$ 5	

(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.

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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.

The State of Illinois has developed a NOx control regulation for utility boilers in the State consistent with a United States Environmental Protection Agency (EPA) program aimed at reducing ozone levels in the Eastern United States. As a result of these state requirements, Generating Company anticipates a 75% reduction from current levels of NOx emissions from its power plant boilers in Illinois by the year 2004. Generating Company estimates spending approximately $210 million for capital expenditures to comply with these rules, of which approximately $50 million was spent in 2001. On February 13, 2002, the EPA proposed similar rules for Missouri which require an approximate 64% reduction from current levels of NOx emissions. AmerenUE estimates approximately $140 million will be required to be spent to comply with these rules for NOx control on the AmerenUE generating system by 2005. The Company is still evaluating the impact of the EPA's regulations as applied to its Missouri operations and may challenge certain aspects of those rules. In summary, the Company currently estimates that its capital expenditures to comply with the final NOx regulations could range from $300 million to $350 million. This estimate includes the assumption that the regulations will require the installation of Selective Catalytic Reduction (SCR) technology on some of the Company's units, as well as additional controls.

Under both Illinois and Missouri regulatory programs, Generating Company and AmerenUE have applied for Early Reduction NOx credits which would allow the companies to manage compliance strategies by either purchasing NOx control equipment or utilizing credits. Generating Company and AmerenUE may be eligible for such credits due to the current low NOx emission rates of some of the Companies' boilers under current state regulations.

In July 1997, the EPA issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. The standards were challenged by industry and some states, and arguments were eventually heard by the U. S. Supreme Court. On February 27, 2001, the Supreme Court upheld the standards in large part, but remanded a number of significant implementation issues back to the EPA for resolution. The EPA is currently working on a new rulemaking to address the issues raised by the Supreme Court. New ambient standards may require significant additional reductions in SO2 and NOx emissions from the Company's power plants by 2008. 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 December 1999, the EPA issued a decision to regulate mercury emissions from coal-fired power plants by 2008. The EPA is scheduled to propose regulations by 2004. These regulations have the potential to add significant capital and/or operating costs to the Ameren generating systems after 2005. On July 20, 2001, the EPA issued proposed Best Available Retrofit Technology (BART) guidelines to address visibility impairment (so called "Regional Haze") across the United States from sources of air pollution, including coal-fired power plants. The guidelines are to be used by States to mandate pollution control measures for SO2 and NOx emissions. These rules could also add significant pollution control costs to the Ameren generating systems between 2008 and 2012.

In addition, the United States Congress has been working on legislation to consolidate the numerous air pollution regulations facing the utility industry. This "multi-pollutant" legislation is expected to be deliberated in Congress in 2002. While the cost to comply with such legislation, if enacted, could be significant, it is anticipated that the costs would be less than the combined impact of the new National Ambient Air Quality Standards, mercury and Regional Haze regulations, discussed above. Pollution control costs under such legislation are expected to be incurred in phases from 2007 through 2015. At this time, the Company is unable to predict the ultimate impact of the above expected regulations and this legislation on its future financial condition, results of operations, or liquidity; however, the impact could be material.

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

The Company owns or is otherwise responsible for 14 former manufactured gas plant (MGP) sites in Illinois. The ICC permits the recovery of remediation and litigation costs associated with certain former MGP sites located in Illinois from the Company's Illinois electric and natural gas utility customers through environmental adjustment clause rate riders. To be recoverable, such costs must be prudently and properly incurred and are subject to annual reconciliation review by the ICC. Through December 31, 2001, the total costs deferred, net of recoveries from insurers and through environmental adjustment clause rate riders, was $26 million.

In addition, the Company owns or is otherwise responsible for 10 MGP sites in Missouri and 1 in Iowa. Unlike Illinois, the Company does not have in effect in Missouri a rate rider mechanism which permits remediation costs associated with MGP sites to be recovered from utility customers, and the Company has no retail utility operations in Iowa.

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

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

With respect to Sauget Area 2, AmerenUE has joined with other PRPs to evaluate the extent of potential contamination. At this time, the Company is unable to predict the ultimate impact of the Sauget Area 2 site on its financial position, results of operations or liquidity.

On September 13, 2001, the EPA proposed in the Federal Register that Sauget Area 1 and Sauget Area 2 be listed on the National Priorities List (NPL). The inclusion of a site on the NPL allows the EPA to access Superfund trust monies to fund site remediations.

In addition, the Company's operations, or that of its predecessor companies, involve the use, disposal and, in appropriate circumstances, the cleanup of substances regulated under environmental protection laws. The Company is unable to determine the impact these actions may have on the Company's 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 66% of the Company's workforce. Contracts with collective bargaining units representing approximately 30% of these employees will expire in 2002. In addition, contracts with collective bargaining units representing approximately 70% of these employees will expire in 2003.

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 12 - 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 utility rates charged to customers provide for recovery of such costs. The DOE is not expected to have its permanent storage facility for spent fuel available until at least 2015. The Company has sufficient storage capacity at the Callaway Nuclear 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 Nuclear Plant.

Electric utility rates charged to customers provide for recovery of Callaway Nuclear 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 $585 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 2001, 2000 and 1999. 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 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 FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 1 - Summary of Significant Accounting Policies).

NOTE 13 - 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, and time value of money and volatility factors.

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

	2001		2000	
In Millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including current portion)	$2,974	$3,052	$2,789	$2,841
Preferred stock	235	207	235	186

The Company has investments in debt and equity securities that are held in trust funds for the purpose of funding the nuclear decommissioning of its Callaway Nuclear Plant (see Note 12 - 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, 2001 and 2000. In 2001, 2000 and 1999, the proceeds from the sale of investments were $230 million, $61 million, and $83 million, respectively. Using the specific identification method to determine cost, the gross realized gains on those sales were approximately $4 million for 2001, $1 million for 2000, and $11 million for 1999. 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:

2001 (In Millions) Security Type	Cost	Gross Unrealized Gain	(Loss)	Fair Value
Debt Securities	$57	$2	$ -	$59
Equity Securities	78	44	-	122
Cash Equivalents	6	-	-	6
	$141	$46	$ -	$187

2000 (In Millions) Security Type	Cost	Gross Unrealized Gain	(Loss)	Fair Value
Debt Securities	$71	$3	$ -	$74
Equity Securities	52	61	-	113
Cash Equivalents	4	-	-	4
	$127	$64	$ -	$191

The contractual maturities of investments in debt securities at December 31, 2001 were as follows:

(In Millions)	Cost	Fair Value
Less than 5 years	$20	$21
5 years to 10 years	22	23
Due after 10 years	15	15
	$57	$59

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NOTE 14 - Segment Information

Ameren's principal business segment is comprised of the utility operating companies that provide electric and gas service in portions of Missouri and Illinois. The other reportable segment includes the nonutility subsidiaries, as well as 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, net income, and total assets of Ameren for the years ended December 31:

(In Millions)	Utility Operations	Other	Reconciling Items	Total
2001				
Revenues	$5,063	$248	$(805)*	$4,506
Net income	467	2	-	469
Total assets	11,171	240	(1,010)	10,401
2000				
Revenues	$4,120	$294	$(557)*	$3,857
Net income	457	-	-	457
Total assets	10,777	287	(1,350)	9,714
1999				
Revenues	$3,467	$243	$(174)*	$3,536
Net income	384	1	-	385
Total assets	8,825	435	(82)	9,178

* Elimination of intercompany revenues.

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

(In Millions)	Utility Operations	Other	Reconciling Items	Total
2001				
Interest expense	$231	$11	$(43)*	$199
Depreciation and amortization expense	382	12	12	406
Income tax expense	289	7	4	300
2000				
Interest expense	$205	$12	$(37)*	$180
Depreciation and amortization expense	360	13	10	383
Income tax expense	297	4	-	301
1999				
Interest expense	$163	$9	$(4)*	$168
Depreciation and amortization expense	349	12	2	363

Income tax expense	261	(2)	-	259

*Elimination of intercompany interest charges

Specified item related to segment assets as of December 31:

(In Millions)	Utility Operations	Other	Reconciling Items	Total
2001				
Expenditures for additions to long-lived assets	$1,059	$10	$34	$1,103
2000				
Expenditures for additions to long-lived assets	$872	$45	$12	$929
1999				
Expenditures for addition to long-lived asset	$342	$179	$50	$571

SELECTED QUARTERLY INFORMATION (Unaudited)

(Thousands of Dollars, Except Per Share Amounts)

Quarter Ended:		Operating Revenues	Operating Income	Net Income (Loss)	Earnings Per Common Share
March 31, 2001	(a)	$1,024,528	$ 116,086	$ 58,492	$ .43
March 31, 2000	(a)	825,376	108,578	61,393	.45
June 30, 2001	(b)	1,057,016	145,203	94,630	.69
June 30, 2000	(b)	940,708	159,206	113,585	.83
September 30, 2001		1,431,613	310,422	266,576	1.94
September 30, 2000	(c)	1,195,723	305,685	256,137	1.87
December 31, 2001		992,710	93,276	48,847	.35
December 31, 2000	(d)	895,023	66,841	25,979	.19

(a) The first quarter of 2001 and 2000 included credits to Missouri electric customers that reduced net income approximately $9 million, or 6 cents per share and $6 million, or 4 cents per share, respectively. The first quarter of 2001 also included an unusual charge for the adoption of a new accounting standard related to derivatives that reduced net income $7 million, or 5 cents per share.

(b) The second quarter of 2001 included a reduction to previously recorded credits to Missouri electric customers that increased net income approximately $15 million, or 10 cents per share. The second quarter of

2000 included credits to Missouri electric customers that reduced net income approximately $3 million, or 2 cents per share.

(c) The third quarter of 2000 included credits to Missouri electric customers that reduced net income approximately $11 million, or 8 cents per share.

(d) The fourth quarter of 2000 included credits to Missouri electric customers that reduced net income approximately $17 million, or 12 cents per share. The fourth quarter of 2000 also included an unusual charge related to the withdrawal from the Midwest ISO that reduced net income $15 million, or 11 cents per share. (See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information).

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

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EXHIBIT 99.2

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Ameren Corporation (Ameren or the Company) 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), which is consolidated for financial reporting purposes. Since the Merger, Ameren has formed several new subsidiaries, including AmerenEnergy, Inc. (AmerenEnergy), Ameren Development Company, AmerenEnergy Resources Company (Resources Company), and Ameren Services Company. AmerenEnergy, an energy trading and marketing subsidiary, primarily serves as a power marketing agent for AmerenUE and AmerenEnergy Generating Company (Generating Company), the nonregulated electric generating subsidiary of Resources Company, and provides a range of energy and risk management services to targeted customers. Ameren Development Company is a nonregulated subsidiary encompassing various nonregulated energy products and services. Resources Company holds Ameren's nonregulated generating operations. Ameren Services Company provides shared support services to Ameren and all of its subsidiaries.

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

RESULTS OF OPERATIONS

Earnings

Earnings for 2001, 2000 and 1999, were $469 million ($3.41 per share before dilution), $457 million ($3.33 per share) and $385 million ($2.81 per share), respectively. Earnings and earnings per share increased over the three-year period primarily due to: the rate of sales growth, weather variations, credits to electric customers, electric rate reductions, gas rate changes, competitive market forces, fluctuating operating costs (including Callaway Nuclear Plant refueling outages), expenses relating to the withdrawal from the electric transmission related Midwest Independent System Operator (Midwest ISO), charges for coal contract terminations, adoption of a new accounting standard, changes in interest expense, and changes in income and property taxes.

In 2001, the Company recorded an after-tax, unusual charge of $7 million, or 5 cents per share, representing the impact of the required adoption of a new accounting standard related to derivative financial instruments (see Note 3 - Risk Management and Derivative Financial Instruments under Notes to Consolidated Financial Statements for further information). In 2000, the Company recorded a $25 million unusual charge to earnings in connection with its withdrawal from the Midwest ISO. The charge reduced earnings $15 million, net of income taxes, or 11 cents per share (see discussion below under "Electric Industry Restructuring" and Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). In 1999, the Company recorded a $52 million 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 11 - Commitments and Contingencies under Notes to Consolidated Financial Statements for further information).

The Company estimates that ongoing earnings per share for the year ending December 31, 2002, will range between $3.15 and $3.45 per share. This estimate incorporates significant assumptions, including resolution of the regulatory issues associated with the Company's Missouri retail electric operations (see discussion below under "Rate Matters" and Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). This estimate assumes a future form of incentive regulation relative to the Company's Missouri electric operations, which could include electric rate reductions and additional customer credits. This estimate is also subject to, among other things, changing energy markets, and economic and weather conditions. Actual results could differ materially from the assumptions used in the Company's 2002 earnings per share estimate.

Electric Operations

Electric Revenues

	Variations from Prior Year		
In Millions	2001	2000	1999
Rate variations	$ -	$ -	$(17)
Credit to customers	75	(27)	5
Effect of abnormal weather	10	(4)	(53)
Growth and other	117	136	78
Interchange sales	480	135	159
EEI sales	(53)	(13)	24
	$ 629	$ 227	$ 196

Electric revenues for 2001 increased $629 million, compared to the prior year period, primarily driven by a 19% increase in total kilowatthour sales. Interchange sales increased 85%; however, lower electric margins were realized on these sales due to lower energy prices in the wholesale markets. Residential sales were comparable to the prior year while commercial sales rose 1%. Industrial sales rose 11% primarily due to a new electric service industrial contract effective August 2000. Revenues were also favorably impacted by a reduction in the estimated credits to Missouri electric customers (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). These increases were partially offset by reduced EEI sales.

Electric revenues for 2000 increased $227 million, compared to the prior year period, primarily due to an 8% increase in total kilowatthour sales. This increase was primarily driven by a 35% increase in interchange sales reflecting the marketing efforts of AmerenEnergy. In addition, residential and commercial sales rose 6% and 8%, respectively, while industrial and wholesale sales rose 3% and 41%, respectively. These increases were offset in part by an increase in the credits to Missouri electric customers (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information).

Electric revenues for 1999 increased $196 million, compared to 1998, primarily due to a 9% increase in total kilowatthour sales. This increase was primarily driven by a 53% increase in interchange sales, due to strong marketing efforts at 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).

Fuel and Purchased Power	Variations from Prior Year		
In Millions	2001	2000	1999
Fuel:			
Generation	$ (19)	$ 49	$ 10
Price	28	(33)	(15)
Generation efficiencies and other	(6)	(13)	(8)
Coal contract termination payments	-	(52)	52
Purchased power	579	92	117
EEI	(45)	9	37
	$ 537	$ 52	$ 193

The $537 million increase in fuel and purchased power costs for 2001, compared to 2000, was primarily due to increased purchased power, resulting from higher interchange sales and the spring 2001 refueling outage at the Company's Callaway Nuclear Plant, in addition to higher blended fuel costs.

The $52 million increase in fuel and purchased power costs for 2000, compared to 1999, was primarily due to increased generation and purchased power, resulting from higher sales volume, partially offset by lower fuel costs, due to the termination of certain coal contracts in the fourth quarter of 1999.

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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 an unusual charge in the fourth quarter of 1999. See Note 11 - Commitments and Contingencies under Notes to Consolidated Financial Statements for further information.

Gas Operations

Gas revenues in 2001 increased $18 million, compared to 2000, primarily due to higher gas costs recovered through the Company's purchased gas adjustment clauses, partially offset by lower total sales of 9% resulting from unusually warm winter weather. Gas revenues in 2000 increased $96 million, compared to 1999, primarily due to increases in retail sales, due to unusually cold weather, and an annualized $4 million Missouri gas rate increase, which became effective in November 2000. Gas revenues in 1999 increased $12 million, compared to 1998, primarily due to an annualized $9 million Illinois gas rate increase, 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.

Gas costs in 2001 increased $12 million, compared to 2000, primarily due to higher gas prices, partially offset by lower total sales. Gas costs in 2000 increased $78 million, compared to 1999, primarily due to higher sales and higher gas prices. Gas costs in 1999 increased $13 million, compared to 1998, primarily due to higher gas prices, partially offset by lower total sales.

Other Operating Expenses

Other operating expense variations in 1999 through 2001 reflected recurring factors, such as growth, inflation, labor and benefit variations, the capitalization of certain costs as a result of a Missouri Public Service Commission (MoPSC) Order and charges for estimated costs relating to withdrawal from the Midwest ISO as discussed below.

Other operating expenses increased $44 million in 2001, compared to 2000, primarily due to higher employee benefit costs in 2001, resulting from increasing healthcare costs, changes in actuarial assumptions and investment performance of employee benefit plans' assets and increased professional services. Other operating expenses, excluding the Midwest ISO-related unusual charge, increased $10 million in 2000, compared to 1999. This increase was primarily due to increases in injuries and damages expense, and higher labor expenses, offset in part by lower employee benefit costs in 2000, resulting from changes in actuarial assumptions. Other operating expenses decreased $18 million in 1999, compared to 1998. This decrease was primarily due to the 1998 charge for a targeted employee separation plan 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 1999 expenses associated with electric industry deregulation in Illinois.

In November 2000, the Company announced that it was withdrawing from the Midwest ISO to become a member of the Alliance Regional Transmission Organization (Alliance RTO). In the fourth quarter of 2000, the Company recorded a pretax unusual charge to earnings of $25 million ($15 million after income taxes, or 11 cents per share) as a result of the Company's decision to withdraw from the Midwest ISO. This charge related to Ameren's estimated obligation under the Midwest ISO agreement for costs incurred by the Midwest ISO, plus estimated exit costs. See discussion below under "Electric Industry Restructuring" and Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

Maintenance expenses increased $14 million in 2001, compared to 2000, primarily due to a refueling outage at the Callaway Nuclear Plant in 2001. The spring 2001 refueling was completed in 45 days. There was not a refueling in 2000. The next refueling is scheduled for the fall of 2002. Maintenance expenses decreased $3 million in 2000, compared to 1999. This decrease was primarily the result of no Callaway Nuclear Plant refueling outage in 2000, partially offset by increased scheduled fossil power plant maintenance and tree-trimming activity. Maintenance expenses increased $59 million in 1999, compared to 1998. This increase was primarily due to increased fossil power plant maintenance and tree-trimming activity.

Depreciation and amortization expense increased $23 million and $20 million in 2001 and 2000, respectively, compared to prior year periods, due to increased depreciable property, primarily resulting from the addition of combustion turbine generating facilities (see discussion below under "Liquidity and Capital Resources" and "Electric Industry Restructuring" for further information). Depreciation and amortization expense in 1999 was comparable to 1998.

Taxes

Income tax expense for 2001 was comparable to 2000. Income tax expense increased $42 million in 2000, compared to 1999, due to higher pretax income. Income tax expense decreased $9 million in 1999, compared to 1998, due to lower pretax income.

Other tax expense decreased $4 million in 2001, compared to 2000, primarily due to a decrease in gross receipts taxes related to the Company's Illinois jurisdiction. Other tax expense increased $18 million in 2000, compared to 1999, primarily due to a change in the property tax assessment in the state of Illinois. 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.

Other Income and Deductions

Miscellaneous, net decreased $5 million in 2001, compared to 2000, primarily due to decreased charitable contributions. Miscellaneous, net decreased $6 million in 2000, compared to 1999, due to the prior period write-off of certain nonregulated investments, partially offset by increased charitable contributions in 2000. Miscellaneous, net increased $8 million in 1999, compared to 1998, 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.

Interest

Interest expense increased $19 million and $11 million in 2001 and 2000, respectively, compared to prior year periods, primarily due to increased debt levels related to the construction and purchase of combustion turbine generating facilities (see discussion below under "Liquidity and Capital Resources"), partially offset by lower interest rates. Interest expense decreased $13 million in 1999, compared to 1998, primarily due to a lower amount of debt outstanding throughout the year.

LIQUIDITY AND CAPITAL RESOURCES

Cash provided by operating activities totaled $738 million for 2001, compared to $856 million for 2000, and $918 million for 1999. Cash flow from operations decreased over the three-year period principally due to the timing of credits provided to the Company's Missouri electric customers and changes in working capital requirements, partially offset by increased earnings.

Cash flows used in investing activities totaled $1.1 billion, $910 million and $558 million, for the years ended December 31, 2001, 2000 and 1999, respectively. Expenditures in 2001 for constructing new or improving existing facilities, net of allowance for funds used during construction, were $1.1 billion, $915 million for 2000, and $557 million for 1999. Included in these amounts were approximately $424 million for the purchase of new combustion turbine generating facilities in 2001 and $350 million in 2000. The Company added 820 megawatts and 692 megawatts of combustion turbine generating capacity during 2001 and 2000, respectively. In addition, the Company spent $24 million in 2001 and $22 million in both 2000 and 1999, to acquire nuclear fuel.

Capital expenditures are expected to approximate $800 million in 2002. For the five-year period 2002 through 2006, construction expenditures are estimated to approximate $3.5 billion. This estimate includes capital expenditures related to the purchase of new combustion turbine generating facilities (see Note 11 - Commitments and Contingencies under Notes to Consolidated Financial Statements for further information), and the replacement of four steam generators at its Callaway Nuclear Plant. In addition, this estimate includes capital expenditures for transmission, distribution and other generation-related activities, as well as for compliance with new NOx control regulations, as

discussed below. The Company plans to add 710 megawatts (approximately 470 megawatts at Resources Company and 240 megawatts at AmerenUE) of combustion turbine generating capacity during 2002. Total costs expected to be incurred for these combustion turbine generating units approximate $340 million. Due to expected increased demand, and the need to maintain appropriate reserve margins, the Company believes it will need additional regulated generating capacity in the future. In 2002, AmerenUE expects to purchase up to 500 megawatts of capacity for the summer. Additional future resource options under consideration by the Company include the transfer of AmerenUE's Illinois-based electric and gas business to AmerenCIPS. Other alternatives include the addition of 650 megawatts of combustion turbine generating units. These units are estimated to cost $280 million and would be added subsequent to 2004. As of December 31, 2001, the Company had noncancelable reservation commitments of $22 million related to the potential purchase of these units. The Company continually reviews its generation portfolio and expected electrical needs, and as a result, could modify its plan for generation asset purchases, which could include the timing of when certain assets will be added to, or removed from its portfolio, whether the generation will be added to the regulated or nonregulated portfolio, the type of generation asset technology that will be employed, or whether capacity may be purchased, among other things. Changes to the Company's plans for future generating needs could result in losses being incurred by the Company, which could be material.

In the ordinary course of business, the Company evaluates several strategies to enhance its financial position, earnings, and liquidity. These strategies may include potential acquisitions, divestitures, opportunities to reduce costs or increase revenues, and other strategic initiatives in order to increase shareholder value. The Company is unable to predict which, if any of these initiatives will be executed, as well as the impact these initiatives may have on the Company's future financial position, results of operations or liquidity.

Environmental

The State of Illinois has developed a NOx control regulation for utility boilers in the State consistent with a United States Environmental Protection Agency (EPA) program aimed at reducing ozone levels in the Eastern United States. As a result of these state requirements, Generating Company anticipates a 75% reduction from current levels of NOx emissions from its power plant boilers in Illinois by the year 2004. Generating Company estimates spending approximately $210 million for capital expenditures to comply with these rules, of which approximately $50 million was spent in 2001. On February 13, 2002, the EPA proposed similar rules for Missouri which require an approximate 64% reduction from current levels of NOx emissions. AmerenUE estimates approximately $140 million will be required to be spent to comply with these rules for NOx control on the AmerenUE generating system by 2005. The Company is still evaluating the impact of the EPA's regulations as applied to its Missouri operations and may challenge certain aspects of those rules. In summary, the Company currently estimates that its capital expenditures to comply with the final NOx regulations could range from $300 million to $350 million. This estimate includes the assumption that the regulations will require the installation of Selective Catalytic Reduction (SCR) technology on some of the Company's units, as well as additional controls.

Under both Illinois and Missouri regulatory programs, Generating Company and AmerenUE have applied for Early Reduction NOx credits which would allow the companies to manage compliance strategies by either purchasing NOx control equipment or utilizing credits. Generating Company and AmerenUE may be eligible for such credits due to the current low NOx emission rates of some of the Companies' boilers under current regulations.

In July 1997, the EPA issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. The standards were challenged by industry and some states, and arguments were eventually heard by the U. S. Supreme Court. On February 27, 2001, the Supreme Court upheld the standards in large part, but remanded a number of significant implementation issues back to the EPA for resolution. The EPA is currently working on a new rulemaking to address the issues raised by the Supreme Court. New ambient standards may require significant additional reductions in sulfur dioxide (SO2) and NOx emissions from the Company's power plants by 2008. 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.

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In December 1999, the EPA issued a decision to regulate mercury emissions from coal-fired power plants by 2008. The EPA is scheduled to propose regulations by 2004. These regulations have the potential to add significant capital and/or operating costs to the Ameren generating system after 2005. On July 20, 2001, the EPA issued proposed Best Available Retrofit Technology (BART) guidelines to address visibility impairment (so called "Regional Haze") across the United States from sources of air pollution, including coal-fired power plants. The guidelines are to be used by States to mandate pollution control measures for SO2 and NOx emissions. These rules could also add significant pollution control costs to the Ameren generating systems between 2008 and 2012.

In addition, the United States Congress has been working on legislation to consolidate the numerous air pollution regulations facing the utility industry. This "multi-pollutant" legislation is expected to be deliberated in Congress in 2002. While the cost to comply with such legislation, if enacted, could be significant, it is anticipated that the costs would be less than the combined impact of the new National Ambient Air Quality Standards, mercury and Regional Haze regulations, discussed above. Pollution control costs under such legislation are expected to be incurred in phases from 2007 through 2015. At this time, the Company is unable to predict the ultimate impact of the above expected regulations and this legislation on its future financial condition, results of operations, or liquidity; however, the impact could be material.

See Note 11 - Commitments and Contingencies under Notes to Consolidated Financial Statements for further discussion of environmental matters and Note 12 - Callaway Nuclear Plant under Notes to Consolidated Financial Statements for a discussion of Callaway Nuclear Plant decommissioning costs.

Financing Activities
Cash flows provided by financing activities were $308 million for 2001, compared

to cash flows used in financing activities of $14 million for 2000 and $241 million for 1999. The Company's principal financing activities during 2001 included the issuance of $300 million of long-term debt and $438 million of short-term debt, offset by the redemption of $64 million of long-term debt and the payment of dividends on common stock. The Company's principal financing activities during 2000 and 1999 included the issuances of $703 million and $152 million of long-term debt, the redemptions of $421 million and $174 million of long-term debt and the payment of dividends on common stock, respectively.

In December 2001, Ameren Corporation issued Floating Rate Notes (FRNs) totaling $150 million. Interest accrues on the FRNs at three month LIBOR (reset quarterly) plus 0.95% and is payable quarterly commencing in March 2002. Principal of the FRNs is payable in December 2003. With the proceeds of the FRNs, Ameren Corporation reduced its short-term borrowings. See Note 7 - Long-Term Debt under Notes to Consolidated Financial Statements for further discussion.

In September 2001, the Company began issuing new shares of common stock to satisfy requirements under the Ameren dividend reinvestment and stock purchase plan (DRPlus) and in December 2001, it began issuing new shares of common stock in connection with its 401(k) plans. Previously, these requirements were met by purchasing outstanding shares. Under these plans, the Company issued 830,177 new shares of common stock in 2001.

In January 2002, Ameren Corporation issued 5.70% Notes totaling $100 million. Interest is payable semi-annually on February 1 and August 1 of each year, beginning August 1, 2002, and on the date of maturity, February 1, 2007. The net proceeds were used to reduce short-term borrowings.

In December 2001, the interest rate mode on AmerenCIPS' three series of variable rate tax-exempt pollution control indebtedness totaling $104 million was converted to long-term fixed rates. Terms of the indebtedness ranged from 5% to 5.95% with maturities through 2026.

In April 2001, AmerenCIPS filed with the Securities and Exchange Commission (SEC) a shelf registration statement on Form S-3 authorizing the offering from time to time of senior notes in one or more series with an offering price not to exceed $250 million. The SEC declared the registration statement effective in May 2001. In June 2001, AmerenCIPS issued $150 million of the senior notes with an interest rate of 6.625% due June 2011. Until the release date as described in the registration statement, the senior notes will be secured by a related series of AmerenCIPS' first mortgage bonds. The proceeds of these senior notes were used to repay short-term debt and first mortgage bonds maturing in June 2001.

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In November 2000, Generating Company issued $225 million principal amount 7.75% Senior Notes, Series A due 2005 (Series A Notes) and $200 million principal amount 8.35% Senior Notes, Series B due 2010 (Series B Notes) (collectively, the Senior Notes). Generating Company filed an S-4 registration statement with the SEC in 2001 to register the Senior Notes under the Securities Act of 1933, as amended, to permit an exchange offer of the Senior Notes. In 2001, all holders completed their exchange of the Senior Notes for new Series C and D Notes which are identical in all material respects to the Series A Notes and Series B Notes, respectively, except that the new series of notes do not contain transfer restrictions and are registered. With the proceeds of the Senior Notes, Generating Company reduced its short-term borrowings incurred in conjunction with the construction of completed combustion turbine generating facilities, paid for the construction of certain combustion turbine facilities, and funded working capital and other capital expenditure needs. See Note 7 - Long-Term Debt under Notes to Consolidated Financial Statements for further discussion.

In 2002, Generating Company expects to issue additional debt to permanently finance generating capacity additions. This additional debt issuance could be up to $250 million and is expected to be issued in early 2002.

The Company anticipates securing additional financing in 2002. In January 2002, Ameren Corporation filed a shelf registration statement with the SEC on Form S-3 which, upon its effectiveness, will allow the offering from time to time of various forms of debt and equity securities, up to an aggregate offering price of $1 billion. The proceeds from any sale of such securities may be used to finance the Company's subsidiaries' ongoing construction and maintenance programs, to redeem, repurchase, repay or retire outstanding indebtedness, including indebtedness of the Company's subsidiaries, to finance strategic investments in or future acquisitions of other entities or other assets and for other general corporate purposes. At this time, the Company is unable to determine the amount of the additional financing, as well as the additional financing's impact on the Company's financial position, results of operations or liquidity.

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 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 commercial paper (maturities generally within 1 to 45 days) and bank loans. At December 31, 2001, the Company had committed bank lines of credit aggregating $156 million, all of which were unused and available at such date. These lines 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 2002 and 2003, that support commercial paper programs totaling $700 million of which $400 million is for the Company's own use and for the use of its subsidiaries. The remaining $300 million is for the use of the Company's regulated subsidiaries. At December 31, 2001, all of the bank credit agreements were unused; however, due to commercial paper borrowings and other commitments, $126 million of such borrowing capacity was available. The Company had $641 million of short-term borrowings outstanding at December 31, 2001. See Note 6 - Short-Term Borrowings under Notes to Consolidated Financial Statements for further information.

AmerenUE also has a lease agreement that provides for the financing of nuclear fuel. At December 31, 2001, the maximum amount that could be financed under the agreement was $120 million. Cash used in financing for 2001 included $64 million of redemptions under the lease for nuclear fuel, offset by $13 million of issuances. At December 31, 2001, $63 million was financed under the lease. See Note 4 - Nuclear Fuel Lease under Notes to Consolidated Financial Statements for further information.

The following table summarizes the Company's committed credit availability as of December 31, 2001:

	Amount of commitment expiration per period			
In Millions	Total amounts committed	Less than 1 year	1 - 3 years	4 - 5 years
Lines of credit and credit agreements (a)	$856	$656	$200	$ -

(a) See Note 6 - Short-Term Borrowings under Notes to Consolidated Financial

Statements for further discussion.

The following table summarizes the Company's contractual obligations as of December 31, 2001:

In Millions	Less than 1 year	1 - 3 years	4 - 5 years
Long-term debt and capital lease obligations (a)	$ 139	$ 684	$ 279
Operating leases	13	27	19
Other long-term obligations (b)	739	1,339	654
Total cash contractual obligations	$ 891	$2,050	$ 952

(a) See Note 7 - Long-Term Debt and Note 4 - Nuclear Fuel Lease under Notes to Consolidated Financial Statements for further discussion.
(b) Represents purchase contracts for coal, gas, nuclear fuel, and electric capacity.

During 2001, as a result of the uncertainty created from the excess earnings complaint filed against AmerenUE (see discussion below under "Rate Matters"), as well as other factors, Moody's, Standard & Poor's and Fitch rating agencies changed their outlooks for Ameren Corporation's long-term unsecured debt ratings from stable to negative. As of December 31, 2001, the ratings of Ameren Corporation by these rating agencies were as follows:

	Moody's	Standard & Poor's	Fitch
Unsecured Debt	A2	A	A+
Commercial Paper	P-1	A-1	F1

If the ratings of AmerenUE's first mortgage bonds, currently rated as Aa3, A+, and AA, for Moody's, Standard & Poor's, and Fitch, respectively, fall below investment grade, lenders on AmerenUE's $300 million revolving credit facility may elect not to make advances and/or declare outstanding borrowings due and payable. In addition, a decrease in the Company's ratings may reduce its access to capital and/or increase the costs of borrowings resulting in a negative impact on earnings.

DIVIDENDS

Common stock dividends paid in 2001, 2000, and 1999 resulted in payout rates of 74%, 76%, and 90%, respectively, of the Company's net income. Dividends paid to common stockholders in relation to net cash provided by operating activities for the same periods were 47%, 41% and 38%.

The Board of Directors does not set specific targets or payout parameters when declaring common stock dividends; 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 8, 2002, the Ameren Board of Directors declared a quarterly common stock dividend of 63.5 cents per share, to holders of record on March 11, 2002, payable March 29, 2002.

RATE MATTERS

On June 30, 2001, AmerenUE's experimental alternative regulation plan (the Plan) for its Missouri retail electric customers expired (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information about the Plan). On July 2, 2001, the MoPSC staff filed with the MoPSC an excess earnings complaint against AmerenUE that proposed to reduce its annual electric revenues ranging from $213 million to $250 million. Factors contributing to the MoPSC staff's recommendation included return on equity (ROE), revenues and customer growth, depreciation rates and other cost of service expenses. The ROE incorporated into the MoPSC staff's recommendation ranged from 9.04% to 10.04%. The MoPSC is not bound by the MoPSC staff's recommendation. In January 2002, the MoPSC issued an order that established the test year to be used to determine rates as July 1, 2000 through June 30, 2001, with updates to that test year permitted through September 30, 2001. The MoPSC staff had utilized a test year of July 1, 1999 through June 30, 2000 in its original complaint. In addition, the MoPSC order stated that AmerenUE would be permitted to propose an incentive regulation plan in this proceeding.

The MoPSC order also included a revised procedural schedule to allow all parties additional time to review data and file testimony, due to the utilization of a more current test year. Under the new schedule, the MoPSC staff will file direct testimony on March 1, 2002, with AmerenUE and the Office of Public Counsel filing rebuttal testimony on May 10, 2002. Evidentiary hearings on the MoPSC staff's recommendation are scheduled to be conducted before the MoPSC beginning in July 2002. In the event that the MoPSC ultimately determines that a rate decrease is warranted in this case, that rate reduction would be retroactive to April 1, 2002, regardless of when the MoPSC issues its decision. A final decision on this matter may not occur until the fourth quarter of 2002. Depending on the outcome of the MoPSC's decision, further appeals in the courts may be warranted.

In the interim, the Company expects to continue negotiations with all pertinent parties with the intent to continue with an incentive regulation plan. The Company cannot predict the outcome of these negotiations and their impact on the Company's financial position, results of operations or liquidity; however, the impact could be material.

See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further discussion of Rate Matters.

ELECTRIC INDUSTRY RESTRUCTURING

Federal

Steps taken and being considered at the federal and state levels continue to change the structure of the electric industry and utility regulation. 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 Federal Energy Regulatory Commission (FERC) the authority to order electric utilities to provide transmission access to third parties.

Order 888 and Order 889, issued by the FERC, 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 stranded 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.

In 1998, AmerenUE and AmerenCIPS joined a group of companies that originally supported the formation of the Midwest ISO. An ISO operates, but does not own, electric transmission systems and maintains system reliability and security, while facilitating wholesale and retail competition through the elimination of "pancaked" transmission rates. The Midwest ISO is regulated by the FERC. The FERC conditionally approved the formation of the Midwest ISO in September 1998.

In December 1999, the FERC issued Order 2000 relating to Regional Transmission Organizations (RTOs) that would meet certain characteristics such as size and independence. RTOs, including ISOs, are entities that ensure comparable and non-discriminatory access to regional electric transmission systems. Order 2000 calls on all transmission owners to join RTOs.

In the fourth quarter of 2000, the Company announced its intention to withdraw from the Midwest ISO and to join the Alliance RTO, and recorded a pretax charge to earnings of $25 million ($15 million after taxes, or 11 cents per share), which related to the Company's estimated obligation under the Midwest ISO agreement for costs incurred by the Midwest ISO, plus estimated exit costs. In 2001, the Company announced that it had signed an agreement to join the Alliance RTO. In a proceeding before the FERC, the Alliance RTO and the Midwest ISO reached an agreement that would enable Ameren to withdraw from the Midwest ISO and to join the Alliance RTO. This settlement agreement was approved by the FERC. The Company's withdrawal from the Midwest ISO remains subject to MoPSC approval. In July 2001, the FERC conditionally approved the formation, including the rate structure, of the Alliance RTO. However, on December 20, 2001, the FERC issued an order that reversed its position and rejected the formation of the Alliance RTO. Instead, the FERC granted RTO status to the Midwest ISO and ordered the Alliance RTO Companies and the Midwest ISO to discuss how the Alliance RTO business model could be accommodated within the Midwest ISO. The Alliance RTO members have until February 19, 2002 to respond to the FERC's December 2001 order. At this time, the Company is evaluating its alternatives, including the possible appeal of the FERC's December 2001 order, and is unable to determine the impact that the FERC's latest ruling will have on its future financial condition, results of operations or liquidity.

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Illinois

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 supplier. The phase-in of retail direct access began on October 1, 1999, with large commercial and industrial customers principally comprising the initial group. The remaining commercial and industrial customers in Illinois were offered choice on December 31, 2000. Commercial and industrial customers in Illinois represented approximately 16% of the Company's total sales during 2001. As of December 31, 2001, the impact of Illinois retail direct access on the

Company's financial condition, results of operations or liquidity was immaterial. Retail direct access will be offered to Illinois residential customers on May 1, 2002.

Under the Illinois Law, the Company is subject to a residential electric rate decrease of up to 5% in 2002, to the extent its rates exceed the Midwest utility average at that time. In 2001, the Company's Illinois electric rates were below the Midwest utility average.

The Illinois Law also contains a provision allowing for the potential recovery of a portion of stranded 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. See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

In conjunction with another provision of the Illinois Law, on May 1, 2000, following the receipt of all required state and federal regulatory approvals, AmerenCIPS transferred its electric generating assets and liabilities, at historical net book value, to Generating Company, in exchange for a promissory note from Generating Company in the principal amount of approximately $552 million and Generating Company common stock (the Transfer). The promissory note bears interest at 7% and has a term of five years payable based on a 10-year amortization. The transferred assets represent a generating capacity of approximately 2,900 megawatts. Approximately 45% of AmerenCIPS' employees were transferred to Generating Company as part of the transaction.

In conjunction with the Transfer, an electric power supply agreement was entered into between Generating Company and its newly created nonregulated affiliate, AmerenEnergy Marketing Company (Marketing Company), also a wholly-owned subsidiary of Resources Company. Under this agreement, Marketing Company is entitled to purchase all of Generating Company's energy and capacity. This agreement may not be terminated until at least December 31, 2004. In addition, Marketing Company entered into an electric power supply agreement with AmerenCIPS to supply it sufficient energy and capacity to meet its obligations as a public utility. This agreement expires December 31, 2004. Power will continue to be jointly dispatched between AmerenUE and Generating Company.

The creation of the new subsidiaries and the transfer of AmerenCIPS' generating assets and liabilities had no effect on the consolidated financial statements of Ameren as of the date of the Transfer.

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

In Missouri, where approximately 70% of the Company's retail electric revenues are derived, restructuring bills have been introduced but no legislation has been passed. Furthermore, no restructuring legislation is expected to be passed by the Missouri state legislature in 2002.

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. Conversely, a deregulated marketplace can provide earnings enhancement opportunities. The Company will continue to focus on cost control to ensure that it maintains a competitive cost structure. Also, in Illinois, the Company's actions included the establishment of a nonregulated generating subsidiary, the expansion of its generation assets, which strengthened its trading and marketing operations in order to retain its current customers and obtain new customers, and the enhancement of its information systems. Management believes that these actions 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. 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.

CONTINGENCIES

See Note 2 - Regulatory Matters, Note 11 - Commitments and Contingencies and Note 12 - Callaway Nuclear Plant under Notes to Consolidated Financial Statements for material issues existing at December 31, 2001.

ACCOUNTING MATTERS

In January 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." The impact of that adoption resulted in the Company recording a cumulative effect charge of $7 million after taxes to the income statement, and a cumulative effect adjustment of $11 million after income taxes to Accumulated Other Comprehensive Income (OCI), which reduced stockholders' equity. (See Note 3 - Risk Management and Derivative Financial Instruments under Notes to Consolidated Financial Statements for further information). In June 2001, the Derivatives Implementation Group (DIG), a committee of the Financial Accounting Standards Board (FASB) responsible for providing guidance on the implementation of SFAS 133, reached a conclusion regarding the appropriate accounting treatment of certain types of energy contracts under SFAS 133. Specifically, the DIG concluded that power purchase or sales agreements (both forward contracts and option contracts) may meet an exception for normal purchases and sales accounting treatment if certain criteria are met. This guidance was effective beginning July 1, 2001, and did not have a material impact on the Company's financial condition, results of operations or liquidity upon adoption. However, in October and again in December 2001, the DIG revised this guidance, with the revisions effective April 1, 2002. The Company does not expect the impact of the DIG's revisions to have a material effect on the Company's financial condition, results of operations, or liquidity upon adoption.

In September 2001, the DIG issued guidance regarding the accounting treatment for fuel contracts that combine a forward contract and a purchased option contract. The DIG concluded that contracts containing both a forward contract and a purchased option contract are not eligible to qualify for the normal purchases and sales exception under SFAS 133. This guidance is effective as of April 1, 2002. The Company continues to evaluate the impact of this guidance on its future financial condition, results of operations and liquidity; however, the impact is not expected to be material.

In July 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS 141 requires business combinations to be accounted for under the purchase method of accounting, which requires one party in the transaction to be identified as the acquiring enterprise and for that party to allocate the purchase price to the assets and liabilities of the acquired enterprise based on fair market value. It prohibits use of the pooling-of-interests method of accounting for business combinations. SFAS 141 is effective for all business combinations initiated after June 30, 2001, or transactions completed using the purchase method after June 30, 2001. SFAS 142 requires goodwill recorded in the financial statements to be tested for impairment at least annually, rather than amortized over a fixed period, with impairment losses recorded in the income statement. SFAS 142 became effective for the Company on January 1, 2002. SFAS 141 and SFAS 142 did not have a material effect on the Company's financial position, results of operations or liquidity upon adoption.

In addition, in July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires an entity to record a liability and corresponding asset representing the present value of legal obligations associated with the retirement of tangible, long-lived assets. SFAS 143 is effective for fiscal years beginning after June 15, 2002. At this time, the Company is assessing the impact of SFAS 143 on its financial position, results of operations and liquidity upon adoption. However, SFAS 143 is expected to result in significant increases to the Company's reported assets and liabilities as a result of its ongoing collection through rates of and obligations associated with Callaway Nuclear Plant decommissioning costs.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of." SFAS 144 retains the guidance related to calculating and recording impairment losses, but adds guidance on the accounting for discontinued operations, previously accounted for under Accounting Principles Board Opinion No. 30. SFAS 144 was adopted by the Company on January 1, 2002. SFAS 144 did not have a material effect on the Company's financial position, results of operations or liquidity 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 Illinois Commerce Commission (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 Company's retail electric utility jurisdictions, the cost of fuel for electric generation is reflected in base rates with no provision for changes in such cost to be reflected in billings to customers through fuel adjustment clauses. Changes in gas costs relating to retail gas utility services are generally reflected in billings to customers through purchased gas adjustment clauses. The Company is impacted by changes in market prices for natural gas to the extent it must purchase natural gas to run its combustion turbine generators. The Company has structured various supply agreements to maintain access to multiple gas pools and supply basins to minimize the impact to the financial statements (see discussion below under "Commodity Price Risk" for further information).

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk represents the risk of changes in value of a physical asset or a financial instrument, derivative or non-derivative, caused by fluctuations in market variables (e.g., interest rates, 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, and operational risk and are not represented in the following analysis.

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

Interest Rate Risk
The Company is exposed to market risk through changes in interest rates associated with its issuance of both long-term and short-term variable-rate debt and fixed-rate debt, commercial paper, auction-rate long-term debt and auction-rate preferred stock. 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 2002, as compared to 2001, the Company's interest expense would increase by approximately $13 million and net income would decrease by approximately $8 million. This amount has been determined using the assumptions that the Company's outstanding variable-rate debt, commercial paper, auction-rate long-term debt, and auction-rate preferred stock, as of December 31, 2001, continued to be outstanding throughout 2002, and that the average interest rates for these instruments increased 1% over 2001. 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.

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

The Company's physical and financial instruments are subject to credit risk consisting of trade accounts receivables and executory contracts with market risk exposures. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising the Company's customer base. No customer represents greater than 10% of the Company's accounts receivable. The Company's revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. The Company analyzes each counterparty's financial condition prior to entering into forwards, swaps, futures or option contracts. The Company also establishes credit limits for these counterparties and monitors the appropriateness of these limits on an ongoing basis through a credit risk management program which involves daily exposure reporting to senior management, master trading and netting agreements, and credit support management (e.g., letters of credit and parental guarantees).

Commodity Price Risk
The Company is exposed to changes in market prices for natural gas, fuel and electricity. Several techniques are utilized to mitigate the Company's risk, including utilizing derivative financial instruments. A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset. The derivative financial instruments that the Company uses (primarily forward contracts, futures contracts and option contracts) are dictated by risk management policies.

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 PGA allows the Company to pass on to its retail customers its prudently incurred costs of natural gas.

The Company's subsidiary, AmerenEnergy Fuels and Services Company, a wholly-owned subsidiary of Resources Company, which is responsible for providing fuel procurement and gas supply services on behalf of the Company's operating subsidiaries, and for managing fuel and natural gas price risks. Fixed price forward contracts, as well as futures and options, are all instruments, which may be used to manage these risks. The majority of the Company's fuel supply contracts are physical forward contracts. 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 11 - Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). Over 95% of the required 2002 supply of coal for the Company's coal plants has been acquired at fixed prices for 2002. In addition, approximately 70% of the coal requirements through 2006 are covered by contracts. With regard to the Company's nonregulated electric generating operations, the Company is exposed to changes in market prices for natural gas to the extent it must purchase natural gas to run its combustion turbine generators. The Company's natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to its intermediate and peaking units by optimizing transportation and storage options and minimizing cost and price risk by structuring various supply agreements to maintain access to multiple gas pools and supply basins and reducing the impact of price volatility.

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

With regard to the Company's exposure to commodity price risk for purchased power and excess electricity sales, the Company has a subsidiary, AmerenEnergy, whose primary responsibility includes managing market risks associated with changing market prices for electricity purchased and sold on behalf of AmerenUE and Generating Company.

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 12 - Callaway Nuclear Plant under Notes to Consolidated Financial Statements for further information). As of December 31, 2001, 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.

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Fair Value of Contracts

The Company utilizes derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause (1) an unrealized appreciation or depreciation of the Company's firm commitments to purchase or sell when purchase or sales prices under the firm commitment are compared with current commodity prices; (2) market values of fuel and natural gas inventories or purchased power to differ from the cost of those commodities under the firm commitment; and (3) actual cash outlays for the purchase of these commodities to differ from anticipated cash outlays. The derivatives that the Company uses to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. Ameren primarily uses derivatives to optimize the value of its physical and contractual positions. Ameren continually assesses its supply and delivery commitment positions against forward market prices and internally forecasts forward prices and modifies its exposure to market, credit and operational risk by entering into various offsetting transactions. In general, these transactions serve to reduce price risk for the Company.

The following summarizes changes in the fair value of all contracts marked to market during 2001:

In Millions	
Fair value of contracts at January 1, 2001	$(30)
Contracts at January 1, 2001 which were realized or	

otherwise settled during 2001	30
Changes in fair values attributable to changes in valuation techniques and assumptions	-
Fair value of new contracts entered into during 2001	4
Other changes in fair value	(5)
Fair value of contracts outstanding at December 31, 2001	$(1)

Fair value of contracts as of December 31, 2001 were as follows:

In Millions Sources of fair value	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Mat in e of 5
Prices actively quoted	$-	$(2)	$ -	$ -
Prices provided by other external sources (b)	5	-	-	-
Prices based on models and other valuation methods (c)	-	(2)	(1)	(1
Total	$5	$(4)	$(1)	$(1

(a) Contracts valued at ($1 million) were with noninvestment-grade rated counterparties.
(b) Principally power forward hedges valued based on NYMEX prices for over-the-counter contracts.
(c) Principally coal and SO2 options valued based on a Black-Scholes model that includes information from external sources and Company estimates.

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, and financial performance. 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 the pending AmerenUE excess earnings complaint case and other regulatory actions, including changes in regulatory policy; 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; the effects of participation in a FERC approved RTO, including activities associated with the Midwest ISO and the Alliance RTO; future market prices for fuel and purchased power, electricity, and natural gas, including the use of financial and derivative instruments and volatility of changes in market prices; average rates for electricity in the Midwest; business and economic conditions; the impact of the adoption of new accounting standards; interest rates and the availability of capital; actions of ratings agencies and the effects of such actions; weather conditions; fuel prices and availability; generation plant construction, installation and 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; competition from other generating facilities including new facilities that may be developed in the future; cost and availability of transmission capacity for the energy generated by the Company's generating facilities or required to satisfy energy sales made by the Company; and legal and administrative proceedings.