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

Overview

EXECUTIVE SUMMARY

As we began 2003, Ameren was faced with a weak economy and energy market, electric rate reductions in our Missouri service territory and rising employee benefit costs. To tackle these challenges, we initiated a voluntary retirement program that reduced staffing levels by over 500 people, closed inefficient generating units, took steps to reduce employee benefit costs and focused on cost containment throughout our business. While decisions to undertake these initiatives were difficult, management felt they were necessary to meet investors' expectations and better position Ameren for the future so as to benefit all of our stakeholders.

Strong operating performance at our power plants during 2003 permitted Ameren to offset reduced sales due to milder-than-normal summer weather and to take advantage of better-than-expected interchange power prices. In 2003, our plants produced more electricity in a single year than ever before, resulting in an increased contribution from interchange sales. In 2003, we also successfully completed the acquisition and integration of CILCORP, realizing anticipated synergies.

With the addition of CILCORP, Ameren now serves over 1.7 million electric and over 500,000 natural gas customers in Missouri and Illinois. We are the largest electric utility in Missouri and the second largest electric utility in Illinois. In February 2004, we signed a definitive agreement to purchase from Dynegy the stock of Illinois Power and an additional 20% interest in EEI. We believe Illinois Power is an excellent strategic fit with our core transmission and distribution business and the additional interest in EEI will bring us more value from EEI's low cost generation plant. The acquisition of Illinois Power will add approximately 590,000 electric customers and 415,000 gas customers. Subject to regulatory approval, we expect to complete the acquisition by the end of 2004.

We expect factors positively impacting 2004 earnings to include, among other things, sales growth in our service territory, almost $30 million in gas rate increases for our gas operations, incremental synergies from the CILCORP acquisition and continued cost control. Factors negatively impacting 2004 earnings are expected to be the implementation of a $30 million reduction in annual electric revenues in Missouri in April 2004, a Callaway Nuclear Plant refueling outage in the spring of 2004, and rising employee benefit costs. Our 2004 earnings will also be affected by the short-term dilutive effect of the issuance of common shares in February 2004, the proceeds of which are intended to be ultimately used for the acquisition of Illinois Power and the 20% interest in EEI. However, once completed, we expect these acquisitions to increase our earnings per share.

GENERAL

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company registered with the SEC under the PUHCA. Ameren's primary asset is the common stock of its subsidiaries. Ameren's subsidiaries operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas distribution businesses and non rate-regulated electric generation businesses in Missouri and Illinois. Dividends on Ameren's common stock are dependent on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. See Note 1 – Summary of Significant Accounting Policies to our financial statements for a more detailed description of our principal subsidiaries. Also see the Glossary of Terms and Abbreviations.

- UE, also known as Union Electric Company, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois.
- CIPS, also known as Central Illinois Public Service Company, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.
- Genco, also known as Ameren Energy Generating Company, operates a non rate-regulated electric generation business.
- CILCO, also known as Central Illinois Light Company, is a subsidiary of CILCORP (a holding company) and operates a rate-regulated electric transmission and distribution business, a primarily non rate-regulated electric generation business and a rate-regulated natural gas distribution business in Illinois.

When we refer to our, we or us, it indicates that the referenced information relates to Ameren and its subsidiaries. When we refer to financing or acquisition activities, we are defining Ameren as the parent holding company. When appropriate, our subsidiaries are specifically referenced in order to distinguish among their different business activities.

The financial statements of Ameren are prepared on a consolidated basis and therefore include the accounts of its majority-owned subsidiaries. Results of CILCORP and CILCO reflected in Ameren's consolidated financial statements include the period from the acquisition date of January 31, 2003 through December 31, 2003. See Note 2 – Acquisitions to our financial statements for further information. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

ACQUISITIONS

CILCORP and Medina Valley

On January 31, 2003, Ameren completed the acquisition of all of the outstanding common stock of CILCORP from AES. CILCORP is the parent company of Peoria, Illinois-based CILCO. With the acquisition, CILCO became an indirect Ameren subsidiary, but remains a separate utility company, operating as AmerenCILCO. On February 4, 2003, Ameren also completed the acquisition of Medina Valley, which indirectly owns a 40 megawatt, gas-fired electric generation plant. The results of operations for CILCORP and Medina Valley were included in Ameren's consolidated financial statements effective with the respective January and February 2003 acquisition dates.

Ameren acquired CILCORP to complement its existing Illinois gas and electric operations. The purchase included CILCO's rate-regulated electric and natural gas businesses in Illinois serving approximately 205,000 and 210,000 customers, respectively, of which approximately 150,000 are combination electric and gas customers. CILCO's service territory is contiguous to CIPS' service territory. CILCO also has a non rate-regulated electric and gas marketing business principally focused in the Chicago, Illinois region. Finally, the purchase included approximately 1,200 megawatts of largely coal-fired generating capacity, most of which became non rate-regulated on October 3, 2003, due to CILCO's transfer of 1,100 megawatts of generating capacity to AERG. See Note 1 – Summary of Significant Accounting Policies to our financial statements for further information on the transfer to AERG.

The total acquisition cost was approximately $1.4 billion and included the assumption by Ameren of CILCORP and Medina Valley debt and preferred stock at closing of $895 million and consideration of $479 million in cash, net of $38 million cash acquired. The cash component of the purchase price came from Ameren's issuance in September 2002 of 8.05 million common shares and its issuance in early 2003 of an additional 6.325 million common shares, which together generated aggregate net proceeds of $575 million. See Note 2 – Acquisitions to our financial statements for further information.

Illinois Power

On February 2, 2004, we entered into an agreement with Dynegy to purchase the stock of Decatur, Illinois-based Illinois Power and Dynegy's 20% ownership interest in EEI. Illinois Power operates a rate-regulated electric and natural gas transmission and distribution business serving approximately 590,000 electric and 415,000 gas customers in areas contiguous to our existing Illinois utility service territories. The total transaction value is approximately $2.3 billion, including the assumption of approximately $1.8 billion of Illinois Power debt and preferred stock, with the balance of the purchase price to be paid in cash at closing. Ameren will place $100 million of the cash portion of the purchase price in a six-year escrow pending resolution of certain contingent environmental obligations of Illinois Power and other Dynegy affiliates for which Ameren has been provided indemnification by Dynegy.

Ameren's financing plan for this transaction includes the issuance of new Ameren common stock, which in total, is expected to equal at least 50% of the transaction value. In February 2004, Ameren issued 19.1 million common shares that generated net proceeds of $853 million. Proceeds from this sale and future offerings are expected to be used to finance the cash portion of the purchase price, to reduce Illinois Power debt assumed as part of this transaction, to pay any related premiums and possibly to reduce present or future indebtedness and/or repurchase securities of Ameren or our subsidiaries.

Upon completion of the acquisition, expected by the end of 2004, Illinois Power will become an Ameren subsidiary operating as AmerenIP. The transaction is subject to the approval of the ICC, the SEC, the FERC, the Federal Communications Commission, the expiration of the waiting period under the Hart-Scott-Rodino Act and other customary closing conditions.

In addition, this transaction includes a firm capacity power supply contract for Illinois Power's annual purchase of 2,800 megawatts of electricity from a subsidiary of Dynegy. This contract will extend through 2006 and is expected to supply about 75% of Illinois Power's customer requirements.

For the nine months ended September 30, 2003, Illinois Power had revenues of $1.2 billion, operating income of $130 million, and net income applicable to common shareholder of $88 million, and at September 30, 2003, had total assets of $2.6 billion, excluding an intercompany note receivable from its parent company of approximately $2.3 billion. For the year ended December 31, 2002, Illinois Power had revenues of $1.5 billion, operating income of $164 million, and net income applicable to common shareholder of $158 million, and at December 31, 2002, had total assets of $2.6 billion, excluding an intercompany note receivable from its parent company of approximately $2.3 billion. See also Liquidity and Capital Resources below for the potential impact on credit ratings that could result from the acquisition of Illinois Power. Illinois Power also files quarterly and annual reports with the SEC.

Results of Operations

EARNINGS SUMMARY

Our results of operations and financial position are affected by many factors. Weather, economic conditions and the actions of key customers or competitors can significantly impact the demand for our services. Our results are also affected by seasonal fluctuations caused by winter heating and summer cooling demand. With approximately 90% of Ameren's revenues directly subject to regulation by various state and federal agencies, decisions by regulators can have a material impact on the price we charge for our services. Our non rate-regulated sales are subject to market conditions for power. We principally utilize coal, nuclear fuel, natural gas and oil in our operations. The prices for these commodities can fluctuate significantly due to the world economic and political environment, weather, supply and demand levels and many other factors. We do not have fuel or purchased power cost recovery mechanisms in Missouri or Illinois for our electric utility businesses, but we do have gas cost recovery mechanisms in each state for our gas utility businesses. The electric rates for UE, CIPS and CILCO are largely set through 2006 such that cost decreases or increases will not be immediately reflected in rates. In addition, the gas delivery rates for UE in Missouri are set through June 2006. Fluctuations in interest rates impact our cost of borrowing and pension and postretirement benefits. We employ various risk management strategies in order to try to reduce our exposure to commodity risks and other risks inherent in our business. The reliability of our power plants, and transmission and distribution systems, and the level of operating and administrative costs, and capital investment are key factors that we seek to control in order to optimize our results of operations, cash flows and financial position.

Ameren's net income for 2003, 2002 and 2001, was $524 million ($3.25 per share before dilution), $382 million ($2.61 per share before dilution), and $469 million ($3.41 per share before dilution), respectively. In 2003, Ameren's net income included an after-tax gain ($31 million or 19 cents per share) related to the settlement of a dispute over mine reclamation issues with a coal supplier and a net cumulative effect after-tax gain ($18 million or 11 cents per share) associated with the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The coal contract settlement gain represented a return of coal costs plus accrued interest previously paid to a coal supplier for future reclamation of a coal mine. The SFAS No. 143 net gain resulted principally from the elimination of non-legal obligation costs of removal for non rate-regulated assets from accumulated depreciation.

In 2002, Ameren's net income included restructuring charges of $58 million, net of taxes, or 40 cents per share, which consisted of a voluntary employee retirement program, the retirement of UE's Venice, Illinois plant, and the temporary suspension of operation of two coal-fired generating units at Genco's Meredosia, Illinois plant. See Note 7 – Restructuring Charges and Other Special Items to our financial statements for further information. In 2001, Ameren's net income was reduced by $7 million, net of taxes, or 5 cents per share, due to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

The following table presents a reconciliation of our net income to net income excluding restructuring charges and other special items (e.g. coal contract settlement), as well as the effect of SFAS No. 143 and SFAS No. 133 adoption, all net of taxes, for the years ended December 31, 2003, 2002, and 2001. We believe this reconciliation presents Ameren's results from continuing operations on a more comparable basis. However, net income, or earnings per share, excluding these items is not a presentation defined under GAAP and may not be comparable to other companies or more useful than the GAAP presentation included in our financial statements.

	2003	2002	2001
Net income	$ 524	$ 382	$ 469
Earnings per share – basic	$ 3.25	$ 2.61	$ 3.41
Restructuring charges and other special items, net of taxes	(31)	58	–
SFAS No. 143 adoption – gain, net of taxes	(18)	–	–
SFAS No. 133 adoption – loss, net of taxes	–	–	7
Total restructuring charges and other special items, effect of SFAS No. 143 and SFAS No. 133 adoption, net of taxes - millions	$ (49)	$ 58	$ 7
- per share	$(0.30)	$ 0.40	$ 0.05
Net income, excluding restructuring charges and other special items, effect of SFAS No. 143 and SFAS No. 133 adoption	$ 475	$ 440	$ 476
Earnings per share, excluding restructuring charges and other special items, and the effect of SFAS No. 143 and No. 133 adoption – basic	$ 2.95	$ 3.01	$ 3.46

Excluding the gains and losses discussed above, Ameren's net income increased $35 million, and earnings per share decreased six cents, in 2003 as compared to 2002. The change in net income was primarily due to the acquisition of CILCORP, as discussed below, favorable interchange margins (35 cents per share) due to improved power prices in the energy markets and greater low-cost generation available for sale, organic growth, lower labor costs due to the voluntary employee retirement program implemented in early 2003 (11 cents per share), lower maintenance expenses in Ameren's pre-CILCORP acquisition operations (25 cents per share), and a decrease in Other Miscellaneous Expense as a result of the expensing of economic development and energy assistance programs in the second quarter of 2002 related to the UE Missouri electric rate case settlement. These benefits to Ameren's 2003 net income were partially offset by unfavorable weather conditions (estimated to be 40 to 50 cents per share) primarily due to cooler summer weather in Ameren's pre-CILCORP territory, an electric rate reduction in UE's Missouri service territory that went into effect in April 2003 (11 cents per share), lower sales of emission credits (7 cents per share), higher employee benefit costs and increased common shares outstanding.

Excluding the charges discussed above, Ameren's net income decreased $36 million (45 cents per share) in 2002 as compared to 2001, primarily due to the impact of the settlement of our Missouri electric rate case (26 cents per share), increased costs of employee benefits, higher depreciation (17 cents per share), excluding the effect of the rate case that is included in the 26 cents above, and a decline in industrial sales due to the continued soft economy. Increased average common shares outstanding (8.8 million shares) and financing costs also reduced Ameren's earnings per share in 2002 (29 cents per share). Factors decreasing net income in 2002 were partially offset by favorable weather conditions (estimated to be 20 to 30 cents per share), sales of emission credits by EEI (10 cents per share) and organic growth.

The impact from the acquisitions of CILCORP and Medina Valley and related financings was accretive to Ameren's earnings per share in 2003 by an estimated four cents per share as Ameren realized synergies associated with the acquisitions following the integration of systems and operating practices.

ELECTRIC OPERATIONS

The following table presents the favorable (unfavorable) variations in electric margins, defined as electric revenues less fuel and purchased power, as compared to the prior periods for the years ended December 31, 2003 and 2002. Although electric margin may be considered a non-GAAP measure, we believe it is a useful measure to analyze the change in profitability of our electric operations between periods.

	2003	2002
Electric revenue change:		
CILCORP acquisition	$ 497	$ –
Interchange revenues	80	(109)
Effect of weather (estimate)	(121)	82
Rate reductions	(34)	(47)
Credit to customers	–	(10)
Growth and other (estimate)	46	22
EEI	(51)	75
Total	$ 417	$ 13
Fuel and purchased power change:		
CILCORP acquisition	$(261)	$ –
Fuel:		
Generation and other	(28)	(57)
Price	3	17
Purchased power	63	174
EEI	(7)	(45)
Total	$(230)	$ 89
Net change in electric margins	$ 187	$ 102

2003 versus 2002

Ameren's electric margin increased $187 million in 2003 as compared to 2002. Increases in electric margin in 2003 were primarily attributable to the acquisition of CILCORP, increased interchange margins and organic sales growth, partially offset by unfavorable weather conditions relative to 2002, lower sales of emission credits and rate reductions. CILCORP's electric margin for the eleven months ended December 31, 2003, was $236 million. Interchange margins increased $92 million in 2003 due to improved power prices in the energy markets and increased low-cost generation availability. Average realized power prices on interchange sales increased to approximately $32 per megawatthour in 2003 from approximately $25 per megawatthour in 2002. Availability of coal-fired generating plants increased to 86% in 2003 from 82% in 2002 due to fewer scheduled and unscheduled outages. In addition, there was no refueling outage at the Callaway Nuclear Plant in 2003.

The unfavorable weather conditions were primarily due to cooler summer weather in the second and third quarters of 2003 versus warmer than normal conditions in the same periods in 2002. Cooling degree days were approximately 25% less in 2003 in our service territory compared to 2002 and approximately 10% less compared to normal conditions. Heating degree days in 2003 were comparable to 2002 and normal conditions. In Ameren's pre-CILCORP acquisition service territory, weather-sensitive residential and commercial electric kilowatthour sales declined 4% and 2%, respectively, in 2003 compared to 2002. Industrial electric kilowatthour sales increased 2% in 2003 in Ameren's pre-CILCORP acquisition service territory due to improving economic conditions.

Annual rate reductions of $50 million and $30 million were effective April 1, 2002 and 2003, respectively, as a result of the 2002 UE electric rate case settlement in Missouri, and negatively impacted electric revenues in 2003 and 2002. Revenues will be further reduced at UE by the 2002 UE settlement of the Missouri electric rate case, due to an additional $30 million of annual electric rate reduction effective April 1, 2004.

EEI's revenues decreased in 2003 compared to 2002 due to lower emission credit sales and decreased sales to its principal customer, which also resulted in a decrease in fuel and purchased power. EEI's sales of emission credits were $10 million in 2003 as compared to $38 million in 2002.

Ameren's fuel and purchased power increased in 2003 compared to 2002 due to increased kilowatthour sales related primarily to the addition of CILCORP. Excluding CILCORP, fuel and purchased power decreased in 2003 primarily due to the greater availability of low-cost generation.

2002 versus 2001

Ameren's electric margin increased $102 million in 2002 as compared to 2001. Increases in electric margin in 2002 were primarily attributable to more favorable weather conditions and increased sales of emission credits. In 2002, weather-sensitive residential electric kilowatthour sales increased by 7% and commercial electric kilowatthour sales increased by 2% as cooling degree days were approximately 10% greater in 2002 compared to 2001. However, industrial sales were approximately 5% lower in 2002 as compared to 2001 due primarily to the impact of the soft economy. Revenues were also reduced by $47 million in 2002 due to the settlement of UE's Missouri electric rate case.

Contribution to electric margin from EEI increased in 2002 from 2001 principally due to EEI's sale of $38 million in emission credits, which is included in the overall $75 million increase in EEI revenues. The remaining EEI increase was due to increased sales to its principal customer, which also resulted in an increase in fuel and purchased power.

Interchange revenues decreased in 2002 from 2001 due to lower energy prices and less low-cost generation available for sale, resulting primarily from increased demand for generation from native load customers. Fuel and purchased power decreased in 2002 from 2001 due primarily to lower energy prices, partially offset by increased fuel and purchase power costs due to increased kilowatthour sales and unscheduled plant outages.

During 2002, we adopted the provisions of EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," that required revenues and costs associated with certain energy contracts to be shown on a net basis in the Consolidated Statement of Income. See also Note 1 – Summary of Significant Accounting Policies to our financial statements for further information on the impact of netting these operating revenues and costs.

GAS OPERATIONS

Ameren's gas margin increased $74 million in 2003, as compared to 2002, primarily due to the acquisition of CILCORP (eleven months ended December 31, 2003 - $73 million). Ameren's gas margins decreased $3 million in 2002, as compared to 2001, primarily due to warmer winter weather in early 2002, partially offset by increased gas sales due to colder than normal temperatures in late 2002. Although gas margin may be considered a non-GAAP measure, we believe it is a useful measure to analyze the change in profitability of gas operations between periods.

OPERATING EXPENSES AND OTHER STATEMENT OF INCOME ITEMS

The following table presents the favorable (unfavorable) variations in operating and other expenses as compared to the prior periods for the years ended December 31, 2003 and 2002:

	2003	2002
Other operations and maintenance	$ (64)	$ (70)
Voluntary retirement and other restructuring charges	92	(92)
Coal contract settlement	51	–
Depreciation and amortization	(88)	(25)
Taxes other than income taxes	(37)	(1)
Other income and deductions	34	(48)
Interest	(63)	(23)
Income taxes	(64)	68

Other Operations and Maintenance

Ameren's other operations and maintenance expenses increased $64 million in 2003, as compared to 2002, primarily due to the addition of CILCORP (eleven months ended December 31, 2003 - $135 million), transition costs related to the CILCORP acquisition, higher employee benefit costs ($17 million) and a net increase in injuries and damages reserves based on claims experience ($6 million). These increases in other operations and maintenance expenses were partially offset by lower labor costs resulting primarily from the voluntary employee retirement program implemented in early 2003 and lower plant maintenance costs primarily due to the number and timing of outages ($60 million). There was not a refueling outage at the Callaway Nuclear Plant in 2003. See also Equity Price Risk for a discussion of our expectations and plans regarding trends in employee benefit costs.

Ameren's other operations and maintenance expenses increased $70 million in 2002, as compared to 2001, primarily due to higher employee benefit costs ($35 million) related to increasing healthcare costs and the investment performance of employee benefit plans' assets, higher wages and higher plant maintenance expenses ($34 million).

Voluntary Retirement and Other Restructuring Charges and Coal Contract Settlement

See Note 7 – Restructuring Charges and Other Special Items to our financial statements for information.

Depreciation and Amortization

Ameren's depreciation and amortization expenses increased $88 million in 2003 as compared to 2002. The increase at Ameren was primarily due to the inclusion of CILCORP operations in 2003 (eleven months ended December 31, 2003 - $72 million). In addition, Ameren's depreciation and amortization expenses increased due to new capital additions.

Ameren's depreciation and amortization expenses increased $25 million in 2002, as compared to 2001, primarily due to investment in CTs and coal-fired power plants. The increase was partially offset by a reduction of depreciation rates ($15 million) based on an updated analysis of asset values, service lives and accumulated depreciation levels that were required by UE's 2002 Missouri electric rate case settlement.

Taxes Other Than Income Taxes

Ameren's taxes other than income taxes increased $37 million in 2003, as compared to 2002, primarily due to the acquisition of CILCORP (eleven months ended December 31, 2003 - $34 million). Taxes other than income taxes in 2002 were comparable to 2001.

Other Income and Deductions

Ameren's other income and deductions increased $34 million in 2003, as compared to 2002, primarily due to the expensing of economic development and energy assistance programs required by the UE Missouri electric rate case settlement in 2002 ($26 million). Ameren's other income and deductions also increased in 2003 due to a decrease in the minority interest related to EEI's lower earnings in 2003.

Ameren's other income and deductions decreased $48 million in 2002 as compared to 2001. The decrease was primarily due to the cost of economic development and energy assistance programs required by the settlement of UE's Missouri electric rate case ($26 million) and an increase in the deduction for minority interest earnings principally related to EEI's sale of emission credits ($10 million). See Note 8 – Other Income and Deductions to our financial statements for further information.

Interest

Ameren's interest expense increased $63 million in 2003, as compared to 2002, primarily due to the assumption of CILCORP debt (eleven months ended December 31, 2003 - $48 million). In addition, interest expense was higher in 2003 due to Genco's issuance of $275 million of 7.95% senior notes in June 2002 ($10 million).

Ameren's interest expense increased $23 million in 2002, as compared to 2001, primarily due to the interest expense component associated with the $345 million of adjustable conversion rate equity security units Ameren issued in March 2002 ($16 million) and Genco's issuance of $275 million of 7.95% senior notes in June 2002 ($12 million).

Income Taxes

Ameren's income tax expense increased $64 million in 2003, as compared to 2002, primarily due to higher pre-tax income, partially offset by a lower effective tax rate. The lower effective tax rate was primarily due to an Illinois tax settlement in the third quarter of 2003. Ameren's income tax expense decreased $68 million in 2002, as compared to 2001, primarily due to lower pre-tax income.

Liquidity and Capital Resources

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

The following table presents net cash provided by (used in) operating, investing and financing activities for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	Variance
Net cash provided by operating activities	$1,031	$ 833	$ 198
Net cash used in investing activities	(1,181)	(803)	(378)
Net cash provided by (used in) financing activities	(367)	531	(898)

	2002	2001	Variance
Net cash provided by operating activities	$ 833	$ 738	$ 95
Net cash used in investing activities	(803)	(1,104)	301
Net cash provided by financing activities	531	307	224

CASH FLOWS FROM OPERATING ACTIVITIES

2003 versus 2002

Cash flows provided by operating activities increased in 2003 as compared to 2002. The increase in cash flows provided by operating activities was primarily a result of increased net earnings discussed above under Results of Operations. The increase was reduced by two non-cash components of net earnings, one associated with the gain of $18 million related to the adoption of SFAS No. 143 and the other the $51 million pre-tax gain related to UE's settlement of the coal mine reclamation issues, of which only $15 million was received in cash during 2003.

Partially offsetting these benefits to cash flows from operating activities were increased materials and supplies inventories resulting from increased natural gas volumes being put into storage, principally due to the acquisition of CILCORP, and higher gas prices.

2002 versus 2001

Cash flows provided by operating activities increased for 2002 as compared to 2001. The increase in cash flows from operating activities was primarily due to higher earnings resulting from favorable weather conditions and from sales of emission credits. The increase was partially offset by payments of customer sharing credits under UE's now-expired Missouri electric alternative regulation plan ($40 million), the timing of payments on accounts payable and accrued taxes, and discretionary pension plan contributions of $31 million in 2002.

Pension Funding

We made cash contributions totaling $25 million in 2003 and $31 million in 2002 to our defined benefit retirement plan qualified trusts. A minimum pension liability was recorded at December 31, 2002, which resulted in an after-tax charge to OCI and a reduction in stockholders' equity of $102 million. At December 31, 2003, the minimum pension liability was reduced, resulting in OCI of $46 million and an increase in stockholders' equity. Based on our assumptions at December 31, 2003, we expect to be required under ERISA to fund an average of approximately $115 million annually from 2005 through 2008 in order to maintain minimum funding levels for our pension plans. These amounts are estimates and may change based on actual stock market performance, changes in interest rates, any pertinent changes in government regulations and any prior voluntary contributions. See Note 11 – Retirement Benefits to our financial statements for additional information.

CASH FLOWS FROM INVESTING ACTIVITIES

Cash flows used in investing activities increased in 2003 as compared to 2002. Ameren's increase in cash used in investing activities in 2003 as compared to 2002 was primarily related to $479 million in cash paid for the acquisitions of CILCORP and Medina Valley in early 2003 and capital expenditures for CILCORP in 2003. These increased investing activities in 2003 were partially offset by lower construction expenditures at the other Ameren subsidiaries and lower nuclear fuel expenditures in 2003.

Cash flows used in investing activities decreased for 2002 as compared to 2001. The decrease in cash from investing activities at Ameren was primarily due to lower construction expenditures in 2002.

Construction Expenditures

Ameren's construction expenditures for 2003 were $682 million compared to $787 million in 2002 and $1,102 million in 2001. The expenditures in 2003 principally related to various upgrades at UE's and Genco's coal-fired power plants, NO_x reduction equipment expenditures at CILCO's generating plants, replacements and improvements to the existing electric transmission and distribution and natural gas distribution systems, and construction costs for CTs at UE. In 2002, UE placed into service 240 megawatts of CT capacity (approximately $135 million). In addition, Genco placed into service 470 megawatts of CT capacity (approximately $215 million). Also in 2002, Genco paid approximately $140 million to Development Company for a CT purchased but accrued for in December 2001. In addition, selective catalytic reduction technology was added on two units at one of Genco's coal-fired power plants at a cost of approximately $42 million. In 2001, Genco added approximately 850 megawatts of CT capacity at a total cost of approximately $530 million.

For the five-year period 2004 through 2008, construction expenditures are estimated to range from $3.0 to $3.5 billion, of which approximately $710 million is expected in 2004. This estimate includes capital expenditures for the replacement of steam generators at UE's Callaway Nuclear Plant and for transmission, distribution and other generation-related activities, as well as for compliance with new NO_x control regulations, as discussed below. Also included in the estimate is the addition of new CTs at UE with approximately 330 megawatts of capacity by the end of 2005. Total costs expected to be incurred for these units approximate $140 million, of which approximately $77 million was committed as of December 31, 2003. UE committed to make between $2.25 billion to $2.75 billion of infrastructure investments during the period of January 1, 2002 to June 30, 2006, as part of UE's 2002 Missouri electric rate case settlement. In addition, commitments totaling at least $15 million for gas infrastructure improvements between July 1, 2003 and December 31, 2006 were agreed upon in relation to UE's 2003 Missouri gas rate case settlement.

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. The Clean Air Act creates a marketable commodity called an "allowance." Each allowance gives the owner the right to emit one ton of SO_2. All existing generating facilities have been allocated allowances based on past production and the statutory emission reduction goals. If additional allowances are needed for new generating facilities, they can be purchased from facilities having excess allowances or from SO_2 allowance banks. Our generating facilities comply with the SO_2 allowance caps through the purchase of allowances, the use of low sulfur fuels or through the application of pollution control technology.

The EPA issued a rule in October 1998 requiring 22 eastern states and the District of Columbia to reduce emissions of NO_x in order to reduce ozone in the eastern United States. Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_x emission budget for each state, including Illinois. The EPA rule requires states to implement controls sufficient to meet their NO_x budget by May 31, 2004. In February 2002, the EPA proposed similar rules for Missouri. These are expected to be issued as final rules in the spring of 2004. The compliance date for the Missouri rules is expected to be May 1, 2007.

As a result of these requirements, we have installed a variety of NO_x control technologies on our power plant boilers over the past several years. We currently estimate our future capital expenditures to comply with the final NO_x regulations in Missouri and Illinois between 2004 and 2008 to range from $210 million to $250 million, which is included in our capital expenditure forecast described above. These estimates include the assumption that the regulations will require the installation of selective catalytic reduction technology on some of our units, as well as additional controls.

In 2004, we are seeking regulatory approval to transfer at net book value approximately 550 megawatts (approximately $250 million) of generating capacity from Genco to UE, to satisfy the requirements of UE's 2002 Missouri electric rate case settlement and to meet future UE generating capacity needs. See Note 3 – Rate and Regulatory Matters to our financial statements for further information. This transfer is not included in our estimated capital expenditures above.

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

Potential Future Environmental Capital Expenditure Requirements

The following environmental matters are currently pending, but have not been included in our estimated capital expenditures for the period of 2004 to 2008.

New Source Review

On December 31, 2002, the EPA published in the Federal Register revisions to the NSR programs under the Clean Air Act, governing pollution control requirements for new fossil-fueled generating plants and major modifications to existing plants. On October 27, 2003, the EPA published a set of associated rules governing the routine maintenance, repair and replacement of equipment at power plants. Various northeastern states, the State of Illinois and others, have filed a petition with the United States District Court for the District of Columbia challenging the legality of the revisions to these NSR programs. Other states, various industries and environmental groups have filed to intervene in this challenge. At this time, we are unable to predict the impact if this challenge is successful on our future financial position, results of operations or liquidity.

Interstate Air Quality and Mercury Rules

In mid-December 2003, the EPA issued proposed regulations with respect to SO_2 and NO_x emissions (the "Interstate Air Quality Rule") and mercury emissions from coal-fired power plants. These new rules, if adopted, will require significant additional reductions in these emissions from our power plants in phases, beginning in 2010. The rules are currently under a public review and comment period, and may change before being issued in 2004 or 2005. We preliminarily estimate capital costs based on current technology on the Ameren systems to comply with the SO_2 and NO_x rules, as proposed, to range from $400 million to $600 million by 2010 and from $500 million to $800 million by 2015.

The proposed mercury regulations contain a number of options and the final control requirements are highly uncertain. Ameren estimates additional capital costs to comply with the mercury rules to be up to $100 million by 2010. Depending upon the final mercury rules, similar additional costs would be incurred between 2010 and 2018.

Multi-Pollutant Legislation

The United States Congress has been working on legislation to consolidate the numerous air pollution regulations facing the utility industry. Continued deliberation on this "multi-pollutant" legislation is expected in 2004. The cost to comply with such legislation, if enacted, is expected to be covered by the modifications to our facilities required by combined Interstate Air Quality and Mercury Rules described above.

See Note 14 – Commitments and Contingencies to our financial statements for further discussion of environmental matters.

CASH FLOWS FROM FINANCING ACTIVITIES

Cash flows from financing activities decreased in 2003 compared to 2002. The decrease in cash flows from financing activities was primarily due to an increase in redemptions, repurchases and maturities of long-term debt, payment on the nuclear fuel lease at UE, and the incremental payment of dividends on common stock due to increased shares outstanding. In addition, we had decreased proceeds from the sales of long-term debt and common stock, which totaled $1.1 billion in 2003 compared to $1.6 billion in 2002. Proceeds from the sale of common shares in 2003 and 2002 were primarily used to fund the acquisition of CILCORP which was completed in January 2003. See Note 2 – Acquisitions to our financial statements for further detail.

Cash flows from financing activities increased in 2002 compared to 2001. Ameren's increase in cash flows provided by financing activities was primarily due to the increase in proceeds received from the issuance of long-term debt and sale of common shares offset by an increase in redemptions of short-term and long-term debt and an increase in dividends paid on common stock.

Ameren and UE are authorized by the SEC under PUHCA to have up to an aggregate of $1.5 billion and $1 billion, respectively, of short-term unsecured debt instruments outstanding at any time. In addition, CIPS, CILCORP and CILCO have PUHCA authority to have up to an aggregate of $250 million each of short-term unsecured debt instruments outstanding at any time. Genco is authorized by the FERC to have up to $300 million of short-term debt outstanding at any time.

Short-term Borrowings and Liquidity

Short-term borrowings consist of commercial paper and bank loans (maturities generally within 1 to 45 days). At December 31, 2003, $161 million (2002 - $271 million) of short-term borrowings was outstanding. Average short-term borrowings were $24 million for the year ended December 31, 2003, with a weighted average interest rate of 1.1% (2002 - $65 million with a weighted average interest rate of 1.8%).

Peak short-term borrowings were $228 million for the year ended December 31, 2003, with a weighted average interest rate of 1.2% (2002 - $173 million with a weighted average interest rate of 1.7%).

The following table presents the various committed credit facilities of the Ameren Companies and EEI as of December 31, 2003:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren: (a)			
364-day revolving	July 2004	$235	$235
Multi-year revolving	July 2005	130	130
Multi-year revolving	July 2006	235	235
UE:			
Various 364-day revolving	through May 2004	154	4
Nuclear fuel lease (b)	February 2004	120	53
CIPS:			
Two 364-day revolving	through July 2004	15	15
CILCO:			
Three 364-day revolving	through August 2004	60	60
EEI:			
Two bank credit facilities	through June 2004	45	37
Total		$994	$769

(a) CILCORP and Genco may access the credit facilities through intercompany borrowing arrangements.

(b) Provided for financing of nuclear fuel. The agreement was terminated in February 2004.

At December 31, 2003, we had committed bank credit facilities totaling $829 million, excluding the EEI facilities and the nuclear fuel lease facility, which were available for use by UE, CIPS, CILCO and Ameren Services through a utility money pool arrangement (2002 - $695 million). As of December 31, 2003, $679 million was available under these committed credit facilities (2002 - $445 million), excluding the EEI facilities and the nuclear fuel lease facility. In addition, $600 million of the $829 million may be used by Ameren directly and most of the non rate-regulated affiliates including, but not limited to, Resources Company, Genco, Marketing Company, AFS, AERG and Ameren Energy through a non state-regulated subsidiary money pool agreement. CILCO received final regulatory approval to participate in the utility money pool arrangement in September 2003. CILCORP receives funds through direct loans from Ameren since it is not part of the non state-regulated money pool agreement. The committed bank credit facilities are used to support our commercial paper programs under which $150 million was outstanding at December 31, 2003 (2002 - $250 million). Access to our credit facilities for all Ameren Companies is subject to reduction based on use by affiliates.

AERG received final regulatory approval to participate in our non state-regulated subsidiary money pool arrangement and as a lender only in our utility money pool arrangement in October 2003.

In July 2003, Ameren entered into two new revolving credit facilities totaling $470 million, and in April 2003, UE entered into a new 364-day committed credit facility totaling $75 million. See Note 5 – Short-term Borrowings and Liquidity to our financial statements for a detailed explanation of these credit facilities.

EEI also has two bank credit agreements totaling $45 million that extend through June 2004. At December 31, 2003, $37 million was available under these committed credit facilities.

UE also had a lease agreement that provided for the financing of nuclear fuel. At December 31, 2003, $67 million was financed under the lease (2002 - $113 million). The lease agreement was terminated in February 2004. See Note 6 – Long-term Debt and Equity Financings to our financial statements for further information.

The following table summarizes the amount of commitment expiration per period as of December 31, 2003:

	Total Committed	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Ameren	$600	$235	$365	$–	$–
UE (a)	274	274	–	–	–
CIPS	15	15	–	–	–
CILCO	60	60	–	–	–
EEI	45	45	–	–	–
Total	$994	$629	$365	$–	$–

(a) Includes $120 million facility which supported the nuclear fuel lease. This lease was terminated in February 2004.

In addition to committed credit facilities, a further source of liquidity for Ameren is available cash and cash equivalents. At December 31, 2003, Ameren had $111 million of cash and cash equivalents (2002 - $628 million).

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

Long-term Debt and Equity

The following table presents the issuances of common stock and the issuances, redemptions, repurchases and maturities of long-term debt and preferred stock for the years ended 2003, 2002 and 2001 for Ameren and its subsidiaries. For additional information related to the terms and uses of these issuances and the sources of funds and terms for the redemptions, see Note 6 – Long-term Debt and Equity Financings to our financial statements.

	Month Issued, Redeemed, Repurchased or Matured	2003	2002	2001
Issuances				
Long-term debt				
Ameren:				
5.70% notes due 2007	Jan	$ –	$ 100	$ –
Senior notes due 2007 (a)	Mar	–	345	–
Floating Rate Notes due 2003	Dec	–	–	150
UE:				
5.50% Senior secured notes due 2034	Mar	184	–	–
4.75% Senior secured notes due 2015	Apr	114	–	–
5.10% Senior secured notes due 2018	Jul	200	–	–
4.65% Senior secured notes due 2013	Oct	200	–	–
5.25% Senior secured notes due 2012	Aug	–	173	–
CIPS:				
6.625% Senior secured notes due 2011	Jun	–	–	150
Genco:				
7.95% Senior notes due 2032	Jun	–	275	–
Total long-term debt issuances		$ 698	$ 893	$300
Common stock				
Ameren:				
6,325,000 Shares at $40.50	Jan	$ 256	$ –	$ –
5,000,000 Shares at $39.50	Mar	–	198	–
750,000 Shares at $38.865	Mar	–	29	–
8,050,000 Shares at $42.00	Sep	–	338	–
DRPlus and 401(k) (b)	Various	105	93	33
Total common stock issuances		$ 361	$ 658	$ 33
Total long-term debt and common stock issuances		$1,059	$1,551	$333

	Month Issued, Redeemed, Repurchased or Matured	2003	2002	2001
Redemptions, Repurchases and Maturities				
Long-term debt/capital lease				
Ameren:				
2001 Floating Rate Notes due 2003	Dec	$ 150	$ –	$ –
UE:				
8.25% First mortgage bonds due 2022	Apr	104	–	–
8.00% First mortgage bonds due 2022	May	85	–	–
7.65% First mortgage bonds due 2003	Jul	100	–	–
7.15% First mortgage bonds due 2023	Aug	75	–	–
8.75% First mortgage bonds due 2021	Sep	–	125	–
8.33% First mortgage bonds due 2002	Dec	–	75	–
Commercial paper, net	Various	–	–	19
Peno Creek CT	Dec	3	–	–
CIPS:				
6.99% Series 97-1 first mortgage bonds due 2003	Mar	5	–	–
6.375% Series Z first mortgage bonds due 2003	Apr	40	–	–
7.50% Series X first mortgage bonds due 2007	Apr	50	–	–
6.94% Series 97-1 first mortgage bonds due 2002	Mar	–	5	–
6.96% Series 97-1 first mortgage bonds due 2002	Sep	–	5	–
6.75% Series Y first mortgage bonds due 2002	Sep	–	23	–
Other 6.73% - 6.89% due 2001	Various	–	–	30
CILCORP: (c)				
9.375% Senior bonds due 2029	Sep	17	–	–
8.70% Senior notes due 2009	Sep	31	–	–

	Month Issued, Redeemed, Repurchased or Matured	2003	2002	2001
CILCO: (c)				
6.82% First mortgage bonds due 2003	Feb	$ 25	$ –	$ –
8.20% First mortgage bonds due 2022	Apr	65	–	–
7.80% Two series of first mortgage bonds due 2023	Apr	10	–	–
Hallock substation power modules bank loan due through 2004	Aug	3	–	–
Kickapoo substation power modules bank loan due through 2004	Aug	2	–	–
Medina Valley:				
Secured term loan due 2019	Jun	36	–	–
EEI:				
1991 8.60% Senior MTNs, amortization	Dec	7	6	7
1994 6.61% Senior MTNs, amortization	Dec	7	8	7
Preferred Stock				
UE:				
1.735 Series 1,657,500	Dec	–	42	–
CILCO: (c)				
5.85% Series	Jul	1	–	–
CIPS:				
1993 auction preferred	Dec	30	–	–
Total long-term debt and preferred stock redemptions, repurchases and maturities		$ 846	$ 289	$ 63

(a) A component of the adjustable conversion-rate equity security units. See Note 6 – Long-term Debt and Equity Financings to our financial statements.

(b) Includes issuances of common stock of 2.5 million shares in 2003, 2.3 million shares in 2002 and 0.8 million shares in 2001 under our DRPlus plan and in connection with our 401(k) plans.

(c) Excludes activity prior to the acquisition of CILCORP and CILCO on January 31, 2003.

Ameren

Pursuant to an August 2002 shelf registration statement, Ameren issued approximately $338 million of common stock in 2002 and issued approximately $256 million of common stock in 2003. Net proceeds from the issuances were used to fund the cash portion of the purchase price for our acquisition of CILCORP and for general corporate purposes. In February 2004, Ameren issued, pursuant to the August 2002 shelf registration statement, 19.1 million shares of its common stock at $45.90 per share. Ameren received net proceeds of $853 million, which are expected to provide funds required to pay the cash portion of the purchase price for our acquisition of Illinois Power and Dynegy's 20% interest in EEI and to reduce Illinois Power debt assumed as part of this transaction and pay related premiums. Pending such use, and/or if the acquisition is not completed, we plan to use the net proceeds to reduce present or future indebtedness and/or repurchase securities of Ameren or its subsidiaries. A portion of the net proceeds may also be temporarily invested in short-term instruments. As substantially all of the capacity under the August 2002 shelf registrations was used, we expect to make a new shelf registration statement filing with the SEC in the first quarter of 2004. See Note 2 – Acquisitions to our financial statements for further information.

The acquisitions of CILCORP on January 31, 2003, and Medina Valley on February 4, 2003, included the assumption by Ameren of CILCORP and Medina Valley debt and preferred stock at closing of $895 million. The assumed debt primarily consisted of $250 million 9.375% senior notes due 2029, $225 million 8.70% senior notes due 2009, a $100 million secured floating rate term loan due 2004, other secured indebtedness totaling $279 million and preferred stock of $41 million.

UE

In August 2002, a shelf registration statement filed by UE and its subsidiary trust with the SEC was declared effective. This registration statement permitted the offering from time to time of up to $750 million of various forms of long-term debt and trust preferred securities to refinance existing debt and preferred stock, and for general corporate purposes, including the repayment of short-term debt incurred to finance construction expenditures and other working capital needs. UE issued securities totaling $173 million in 2002 and $498 million in 2003 pursuant to the August 2002 shelf registration statement with the amount of securities that remained available for issuance totaling $79 million as of August 2003. See Note 6 – Long-term Debt and Equity Financings to our financial statements for further information.

In September 2003, the SEC declared effective another shelf registration statement filed by UE and its subsidiary trust in August 2003, covering the offering from time to time of up to $1 billion of various forms of long-term debt and trust preferred securities. The $79 million of securities which remained available for issuance under the August 2002 shelf registration statement is included in the $1 billion of securities available to be issued under this shelf registration statement. UE issued securities totaling $200 million in 2003 pursuant to the September 2003 shelf registration statement with the amount of securities remaining available for issuance totaling $800 million as of December 31, 2003. UE may sell all, or a portion of, the currently remaining securities registered under the September 2003 shelf registration statement if warranted by market conditions and capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

CIPS

In May 2001, a shelf registration statement filed by CIPS with the SEC was declared effective. This registration statement permits the public offering by CIPS from time to time of senior notes in one or more series with an offering price not to exceed $250 million. In June 2001, CIPS issued $150 million of senior notes under the shelf registration statement. At December 31, 2003, the amount of securities remaining available for issuance pursuant to the shelf registration statement was $100 million. CIPS may sell all, or a portion of, the currently remaining securities registered under the May 2001 shelf registration statement if warranted by market conditions and capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

INDEBTEDNESS PROVISIONS AND OTHER COVENANTS

Bank Credit Facilities

Borrowings under Ameren's non state-regulated subsidiary money pool by Genco, Development Company and Medina Valley, each an "exempt wholesale generator," are considered investments for purposes of the 50% SEC aggregate investment limitation. Based on Ameren's aggregate investment in these "exempt wholesale generators" as of December 31, 2003, the maximum permissible borrowings under Ameren's non state-regulated subsidiary money pool pursuant to this limitation for these entities was $663 million in the aggregate.

Our bank credit agreements contain provisions which, among other things, place restrictions on the ability to incur liens, sell assets, merge with other entities and restrict and encumber upstream dividend payments of our subsidiaries. These credit agreements also contain a provision that limits Ameren's, UE's, CIPS', and CILCO's total indebtedness to 60% of total capitalization pursuant to a calculation defined in the related agreement. As of December 31, 2003, the ratio of total indebtedness to total capitalization (calculated in accordance with this provision) for Ameren, UE, CIPS and CILCO was 52%, 44%, 54% and 53%, respectively (2002 - 50%, 43%, 50%, -%). These credit agreement provisions were not applicable in 2002 for CILCO, since CILCO was not a party to, nor subject to the provisions of, these facilities during 2002. In addition, our credit agreements contain indebtedness cross-default provisions and material adverse change clauses, which could trigger a default under these facilities in the event that any of Ameren's subsidiaries (subject to the definition in the underlying credit agreements), other than certain project finance subsidiaries, defaults on indebtedness in excess of $50 million. Our credit agreements also require us to meet minimum ERISA funding rules.

None of the Ameren Companies' credit agreements or financing arrangements contain credit rating triggers with the exception of one of CILCO's financing arrangements. An event of default will occur under a $100 million CILCO bank term loan if the credit rating on CILCO's first mortgage bonds falls below any two of the following: BBB- from S&P, Baa3 from Moody's or BBB- from Fitch. As of December 31, 2003, CILCO's current ratings on its first mortgage bonds were A-, A2 and A, respectively. We expect to repay this term loan in the first quarter of 2004.

At December 31, 2003, Ameren and its subsidiaries were in compliance with their credit agreement provisions and covenants.

Indenture Provisions and Other Covenants

UE

UE's indenture agreements and Articles of Incorporation include covenants and provisions which must be complied with in order to issue first mortgage bonds and preferred stock. UE must comply with earnings tests contained in its respective mortgage indenture and Articles of Incorporation. For the issuance of additional first mortgage bonds, earnings coverage of twice the annual interest charges on first mortgage bonds outstanding and to be issued is required. At December 31, 2003, UE had a coverage ratio of 9.1 times the annual interest charges on the first mortgage bonds outstanding, which would permit UE to issue an additional $4.2 billion of first mortgage bonds. For the issuance of additional preferred stock, earnings coverage of at least 2.5 times the annual dividend on preferred stock outstanding and to be issued is required under UE's Articles of Incorporation. As of December 31, 2003, UE had a coverage ratio of 74.2 times the annual dividend on preferred stock outstanding which would permit UE to issue an additional $2.4 billion in preferred stock. The ability to issue such securities in the future will depend on such tests at that time.

In addition, UE's mortgage indenture contains certain provisions which restrict the amount of common dividends that can be paid by UE. Under this mortgage indenture, $31 million of total retained earnings was restricted against payment of common dividends, except those payable in common stock, leaving $1.6 billion of free and unrestricted retained earnings at December 31, 2003.

CIPS

CIPS' indenture agreements and Articles of Incorporation include covenants which must be complied with in order to issue first mortgage bonds and preferred stock. CIPS must comply with earnings tests contained in its respective mortgage indenture and Articles of Incorporation. For the issuance of additional first mortgage bonds, earnings coverage of twice the annual interest charges on first mortgage bonds outstanding and to be issued is required. As of December 31, 2003, CIPS had a coverage ratio of 2.5 times the annual interest charges for one year on the aggregate amount of bonds outstanding, and consequently, had the availability to issue an additional $66 million of first mortgage bonds. For the issuance of additional preferred stock, earnings coverage of 1.5 times annual interest charges on all long-term debt and preferred stock dividends is required under CIPS' Articles of Incorporation. As of December 31, 2003, CIPS had a coverage ratio of 1.8 times the sum of the annual interest charges and dividend requirements on all long-term debt and preferred stock outstanding as of December 31, 2003, and consequently, had the availability to issue an additional $109 million of preferred stock. The ability to issue such securities in the future will depend on coverage ratios at that time.

Genco

Genco's senior note indenture includes provisions that require it to maintain a senior debt service coverage ratio of at least 1.8 to 1 (for both the prior four fiscal quarters and for the next succeeding four six-month periods) in order to pay dividends to Ameren or to make payments of principal or interest under certain subordinated indebtedness excluding amounts payable under its intercompany note payable with CIPS. For the four quarters ended December 31, 2003, this ratio was 3.8 to 1. In addition, the indenture also restricts Genco from incurring any additional indebtedness, with the exception of certain permitted indebtedness as defined in the indenture, unless its senior debt service coverage ratio equals at least 2.5 to 1 for the most recently ended four fiscal quarters and its senior debt to total capital ratio would not exceed 60%, both after giving effect to the additional indebtedness on a pro-forma basis. This debt incurrence requirement is disregarded in the event certain rating agencies reaffirm the ratings of Genco after considering the additional indebtedness. As of December 31, 2003, Genco's senior debt to total capital was 53%.

CILCORP

Covenants in CILCORP's indenture governing its $475 million (original issuance amount) senior notes and bonds require CILCORP to maintain a debt to capital ratio of no greater than 0.67 to 1 and an interest coverage ratio of at least 2.2 to 1 in order to make any payment of dividends or intercompany loans to affiliates other than to its direct and indirect subsidiaries including CILCO. However, in the event CILCORP is not in compliance with these tests, CILCORP may make such payments of dividends or intercompany loans if its senior long-term debt rating is at least BB+ from S&P, Baa2 from Moody's and BBB from Fitch. At December 31, 2003, CILCORP's debt to capital ratio was 0.6 to 1 and its interest coverage ratio was 3.0 to 1, calculated in accordance with related provisions in this indenture. The common stock of CILCO is pledged as security to the holders of these senior notes and bonds.

CILCO

CILCO must maintain investment grade ratings for its first mortgage bonds from at least two of S&P, Moody's and Fitch. CILCO's current senior secured debt ratings from these rating agencies is A-, A2 and A, respectively. CILCO's $100 million bank term loan placed restrictions on CILCO's ability to pay dividends or otherwise make distributions with respect to its common stock. However, this loan is expected to be repaid in the first quarter of 2004.

DIVIDENDS

Common stock dividends paid by Ameren in 2003 resulted in a payout rate of 78% of Ameren's net income. The payout rate in 2002 was 98% and was 75% in 2001. Dividends paid to common stockholders in relation to net cash provided by operating activities for the same periods were 40%, 45% and 47%.

The amount and timing of dividends payable on Ameren's common stock are within the sole discretion of Ameren's Board of Directors. Ameren's Board of Directors has not set specific targets or payout parameters when declaring common stock dividends. However, the Board considers various issues including Ameren'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. Dividends paid by Ameren to stockholders totaled $410 million or $2.54 per share in 2003 (2002 - $376 million or $2.54 per share; 2001 - $350 million or $2.54 per share). On February 13, 2004, Ameren's Board of Directors declared a quarterly common stock dividend of 63.5 cents per share payable on March 31, 2004, to stockholders of record on March 10, 2004.

Certain of our financial agreements and corporate organizational documents contain covenants and conditions that, among other things, provide restrictions on the payment of dividends. Ameren would experience restrictions on dividend payments if it were to defer contract adjustment payments on its equity security units. UE would experience restrictions on dividend payments if it were to extend or defer interest payments on its subordinated debentures. CIPS has provisions restricting dividend payments based on ratios of common stock to total capitalization along with provisions related to certain operating expenses and accumulations of earned surplus. Genco's indenture includes restrictions which prohibit making any dividend payments if debt service coverage ratios are below a defined threshold. CILCORP has restrictions in the event leverage ratio and interest coverage ratio thresholds are not met or if CILCORP's senior long-term debt does not have specified ratings as described in its indenture. CILCO has restrictions on dividend payments relative to the ratio of its balance of retained earnings to the annual dividend requirement on its preferred stock and amounts to be set aside for any sinking fund retirement of Class A Preferred Stock.

The following table presents dividends paid directly or indirectly to Ameren by its subsidiaries for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
UE	$288	$299	$283
CIPS	62	62	33
Genco	36	21	–
CILCORP (parent company only) (a)	(35)	–(b)	–(b)
CILCO	62	–(b)	–(b)
Non-registrants	–	1	–
Dividends paid to Ameren	$413	$383	$316

(a) Indicates funds retained from the CILCO dividend.

(b) Prior to February 2003, CILCORP's dividends would have been paid to AES.

CONTRACTUAL OBLIGATIONS

The following table presents our contractual obligations as of December 31, 2003. See Note 3 – Rate and Regulatory Matters to our financial statements for information regarding capital expenditure commitments, which were agreed upon in relation to UE's 2002 Missouri electric rate case settlement and UE's 2003 Missouri gas rate case settlement. See Note 11 – Retirement Benefits to our financial statements for information regarding expected minimum funding levels for our pension plan.

	Total	Less than 1 Year	1–3 Years	4-5 Years	More than 5 Years
Long-term debt and capital lease obligations	$4,575	$ 498	$ 302	$ 666	$3,109
Short-term debt	161	161	–	–	–
Operating leases (a)	146	20	25	21	80
Other obligations (b)	3,146	1,033	1,272	622	219
Total cash contractual obligations (c)	$8,028	$1,712	$1,599	$1,309	$3,408

(a) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The $2 million annual obligation for these items is included in the less than 1 year, 1-3 years and 4-5 years. Amounts for more than 5 years are not included in the total amount due to the indefinite periods.

(b) Represents purchase contracts for coal, gas, nuclear fuel and electric capacity.

(c) Routine short-term purchase order commitments are not included.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2003, neither Ameren nor any of its subsidiaries, had any off-balance sheet financing arrangements, other than operating leases entered into in the ordinary course of business. Neither Ameren nor any of its subsidiaries expect to engage in any significant off-balance sheet financing arrangements in the near future.

CREDIT RATINGS

The following table presents the current ratings by Moody's, S&P and Fitch as of December 31, 2003:

	Moody's	S&P	Fitch
Ameren:			
Issuer/Corporate credit rating	A3	A-	A-
Unsecured debt	A3	BBB+	A-
Commercial paper	P-2	A-2	F2
UE:			
Secured debt	A1	A-	A+
Unsecured debt	A2	BBB+	A
Commercial paper	P-1	A-2	F1
CIPS:			
Secured debt	A1	A-	A
Unsecured debt	A2	BBB+	A-
Genco:			
Unsecured debt	A3/Baa2	A-	BBB+
CILCORP:			
Unsecured debt	Baa2	BBB+	BBB+
CILCO:			
Secured debt	A2	A-	A

As a result of the announcement of Ameren signing a definitive agreement to acquire Illinois Power and a 20% interest in EEI from Dynegy in February 2004, credit rating agencies placed Ameren Corporation's and its subsidiaries' debt under review for a possible downgrade.

Any adverse change in our credit ratings may reduce our access to capital and/or increase the costs of borrowings resulting in a negative impact on earnings. At December 31, 2003, if we were to receive a sub-investment grade rating (less than BBB- or Baa3), we could have been required to post collateral for certain trade obligations amounting to $32 million. In addition, the cost of borrowing under our credit facilities would increase or decrease based on credit ratings. A credit rating is not a recommendation to buy, sell or hold securities and should be evaluated independently of any other rating. Ratings are subject to revision or withdrawal at any time by the assigning rating organization.

Outlook

We expect the following industry-wide trends and company-specific issues to impact earnings in 2004 and beyond:

- Economic conditions, which principally impact native load demand, particularly from our industrial customers, have been weak for the past few years, but improved in 2003.
- We have historically achieved weather-adjusted growth in our native electric residential and commercial load of approximately 2% per year and expect this trend to continue for at least the next few years.
- Electric rates in our Illinois service territories are legislatively fixed through January 1, 2007. An electric rate case settlement in UE's Missouri service territory has resulted in reductions of $50 million on April 1, 2002, and $30 million on April 1, 2003, with an additional $30 million reduction required for April 1, 2004. In addition, electric rates in Missouri cannot change prior to July 1, 2006, subject to certain exclusions outlined in UE's rate settlement.
- Power prices in the Midwest impact the amount of revenues we can generate by marketing any excess power into the interchange markets. Power prices in the Midwest also impact the cost of power we purchase in the interchange markets. Long-term power prices continue to be generally soft in the Midwest, despite a significant increase in power prices in 2003 relative to 2002 due in part to higher prices for natural gas.
- Increased expenses associated with rising employee benefit costs and higher insurance and security costs associated with additional measures we have taken, or may have to take, at our Callaway Nuclear Plant and other operating plants related to world events.
- Our Callaway Nuclear Plant will have a refueling outage in the spring of 2004, which is expected to last 40-45 days, and will increase maintenance and purchased power costs, and reduce the amount of excess power available for sale. Refueling outages occur approximately every 18 months and have historically reduced net earnings by $15 to $20 million in the year when they occurred. The fall 2005 refueling outage is expected to last 70 days due to the installation of new steam generator units during the refueling.
- In January 2004, the MoPSC approved a settlement authorizing an annual gas delivery rate increase of approximately $13 million, which went into effect on February 15, 2004. The settlement provides that gas delivery rates cannot change prior to July 1, 2006, subject to certain exclusions. In October 2003, the ICC issued orders awarding CILCO an increase in annual gas delivery rates of $9 million and awarding CIPS and UE increases in annual gas delivery rates of $7 million and $2 million, respectively that went into effect in November 2003. See Note 3 – Rate and Regulatory Matters to our financial statements for additional information.
- Upon entering the Midwest ISO, UE expects to receive a refund of $13 million and CIPS expects to receive a refund of $5 million for fees previously paid to exit the Midwest ISO; however, we will incur higher ongoing operation costs. See Note 3 – Rate and Regulatory Matters to our financial statements for additional information.
- We expect to realize further CILCORP integration synergies associated with reduced overhead expenses and lower fuel costs.
- In February 2004, we sold 19.1 million shares of new Ameren common stock. Proceeds from this sale and future offerings are expected to ultimately be used to finance the cash portion of the purchase price of Illinois Power and to reduce Illinois Power debt assumed as part of this transaction and pay any related premiums. However, prior to the closing of the acquisition of Illinois Power, we expect the new common shares to be dilutive to earnings per share.

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

Regulatory Matters

See Note 3 – Rate and Regulatory Matters to our financial statements.

Accounting Matters

CRITICAL ACCOUNTING POLICIES

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

(See Table on Pages 32 and 33)

Accounting Policy	Uncertainties Affecting Application

REGULATORY MECHANISMS AND COST RECOVERY

We defer costs as regulatory assets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and make investments that we assume will be collected in future rates.

- Regulatory environment, external regulatory decisions and requirements
- Anticipated future regulatory decisions and their impact
- Impact of deregulation and competition on ratemaking process and ability to recover costs

Basis for Judgment

We determine that costs are recoverable based on previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable.

ENVIRONMENTAL COSTS

We accrue for all known environmental contamination where remediation can be reasonably estimated, but some of our operations have existed for over 100 years and previous contamination may be unknown to us.

- Extent of contamination
- Responsible party determination
- Approved methods for cleanup
- Present and future legislation and governmental regulations and standards
- Results of ongoing research and development regarding environmental impacts

Basis for Judgment

We determine the proper amounts to accrue for known environmental contamination based on internal and third party estimates of clean-up costs in the context of current remediation standards and available technology.

UNBILLED REVENUE

At the end of each period, we estimate, based on expected usage, the amount of revenue to record for services that have been provided to customers, but not billed.

- Projecting customer energy usage
- Estimating impacts of weather and other usage-affecting factors for the unbilled period

Basis for Judgment

We determine the proper amount of unbilled revenue to accrue each period based on the volume of energy delivered as valued by a model of billing cycles and historical usage rates and growth by customer class for our service area, as adjusted for the modeled impact of seasonal and weather variations based on historical results.

VALUATION OF GOODWILL, LONG-LIVED ASSETS AND ASSET RETIREMENT OBLIGATIONS

We assess the carrying value of our goodwill and long-lived assets to determine whether they are impaired. We also review for the existence of asset retirement obligations. If an asset retirement obligation is identified, we determine the fair value of the obligation and subsequently reassess and adjust the obligation, as necessary. See Note 1 – Summary of Significant Accounting Policies to our financial statements.

- Management's identification of impairment indicators
- Changes in business, industry, technology or economic and market conditions
- Valuation assumptions and conclusions
- Estimated useful lives of our significant long-lived assets
- Actions or assessments by our regulators
- Identification of an asset retirement obligation

Basis for Judgment

Annually or whenever events indicate a valuation may have changed, we utilize internal models and third parties to determine fair values. We use various methods to determine valuations, including earnings before interest, taxes, depreciation and amortization multiples and discounted, undiscounted and probabilistic discounted cash flow models with multiple scenarios. The identification of asset retirement obligations is conducted through the review of legal documents and interviews.

Accounting Policy	Uncertainties Affecting Application
BENEFIT PLAN ACCOUNTING Based on actuarial calculations, we accrue costs of providing future employee benefits in accordance with SFAS Nos. 87, 106 and 112, which provide guidance on benefit plan accounting. See Note 11 – Retirement Benefits to our financial statements.	■ Future rate of return on pension and other plan assets ■ Interest rates used in valuing benefit obligations ■ Healthcare cost trend rates ■ Timing of employee retirements

Basis for Judgment

We utilize a third party consultant to assist us in evaluating and recording the proper amount for future employee benefits. Our ultimate selection of the discount rate, healthcare trend rate and expected rate of return on pension assets is based on our review of available current, historical and projected rates, as applicable.

IMPACT OF FUTURE ACCOUNTING PRONOUNCEMENTS

See Note 1 – Summary of Significant Accounting Policies to our financial statements.

Effects of Inflation and Changing Prices

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

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

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

Quantitative and Qualitative Disclosures about Market Risk

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

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

INTEREST RATE RISK

We are exposed to market risk through changes in interest rates associated with:

- long-term and short-term variable-rate debt;
- fixed-rate debt;
- commercial paper;
- auction-rate long-term debt; and
- auction-rate preferred stock.

We manage our interest rate exposure by controlling the amount of these instruments we hold within our total capitalization portfolio and by monitoring the effects of market changes in interest rates.

Utilizing our variable debt outstanding at December 31, 2003, if interest rates increased by 1%, our annual interest expense would increase by approximately $9 million and net income would decrease by approximately $6 million based on an effective tax rate of 37%. The model does not consider the effects of the reduced level of potential overall economic activity that would exist in such an environment. In the event of a significant change in interest rates, management would likely take actions to further mitigate our exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no change in our financial structure.

CREDIT RISK

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

Our physical and financial instruments are subject to credit risk consisting of trade accounts receivables, executory contracts with market risk exposures and leveraged lease investments. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising our customer base. No non-affiliated customer represents greater than 10%, in the aggregate, of our accounts receivable. Our revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. Ameren has credit exposure associated with accounts receivables from non-affiliated companies for interchange sales. At December 31, 2003, Ameren's credit exposure to non-investment grade counterparties related to interchange sales was $4 million, net of collateral. We establish credit limits for these counterparties and monitor the appropriateness of these limits on an ongoing basis through a credit risk management program which involves daily exposure reporting to senior management, master trading and netting agreements, and credit support such as letters of credit and parental guarantees. We also analyze each counterparty's financial condition prior to entering into sales, forwards, swaps, futures or option contracts and monitor counterparty exposure associated with our leveraged leases.

EQUITY PRICE RISK

Our costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, such as the rate of return on plan assets, discount rate, the rate of increase in healthcare costs and contributions made to the plans. The market value of our plan assets was affected by declines in the equity market for 2000 through 2002 for the pension and postretirement plans. As a result, at December 31, 2002, we recognized an additional minimum pension liability as prescribed by SFAS No. 87, "Employers' Accounting for Pensions," which resulted in an after-tax charge to OCI and a reduction in stockholders' equity of $102 million. At December 31, 2003, the minimum pension liability was reduced, resulting in OCI of $46 million and an increase in stockholders' equity.

The amount of the pension liability as of December 31, 2003, was the result of asset returns, interest rates and our contributions to the plans during 2003. In future years, the liability recorded, the costs reflected in net income, or OCI, or cash contributions to the plans could increase materially without a recovery in equity markets in excess of our assumed return on plan assets of 8.5%. If the fair value of the plan assets were to grow and exceed the accumulated benefit obligations in the future, then the recorded liability would be reduced and a corresponding amount of equity would be restored, net of taxes, in the Consolidated Balance Sheet.

We also maintain trust funds, as required by the NRC and Missouri and Illinois state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2003, these funds were invested primarily in domestic equity securities (68%), debt securities (30%), and cash and cash equivalents (2%) and totaled $212 million at fair value. By maintaining a portfolio that includes long-term equity investments, we seek to maximize the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in the portfolio are exposed to price fluctuations in equity markets and the fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the 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 the trusts to various investment options. Our exposure to equity price market risk is, in large part, mitigated, due to the fact that we are currently allowed to recover decommissioning costs in our rates.

COMMODITY PRICE RISK

We are exposed to changes in market prices for natural gas, fuel and electricity to the extent we cannot recover them through rates in our regulated businesses. We have electric rate freezes in place in Missouri through June 30, 2006, and Illinois through December 31, 2006. We utilize several techniques to mitigate risk, including utilizing derivative financial instruments. A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset. The derivative financial instruments that we use (primarily forward contracts, futures contracts, option contracts and financial swap contracts) are dictated by risk management policies.

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

We use fixed price forward contracts, as well as futures, options and financial swaps to manage risks associated with fuel and natural gas prices. The majority of our fuel supply contracts are physical forward contracts. Since we do not have a provision similar to the PGA clause for our electric operations, we have entered into long-term contracts with various suppliers to purchase coal and nuclear fuel in order to manage our exposure to fuel prices. See Note 14 – Commitments and Contingencies to our financial statements for further information. With regard to our electric generating operations, we are exposed to changes in market prices for natural gas to the extent we must purchase natural gas to run our CTs. Our natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to our intermediate and peaking units by optimizing transportation and storage options and minimizing cost and price risk by structuring various supply agreements to maintain access to multiple gas pools and supply basins.

The following table presents the percentages of the required supply of coal for our coal-fired power plants, nuclear fuel and natural gas for our CTs and for distribution that are price-hedged for the five-year period 2004 through 2008:

	2004	2005	2006-2008
Coal	96%	67%	41%
Nuclear fuel	100	100	32
Natural gas for generation	38	11	2
Natural gas for distribution	34	14	4

If coal costs were to change by 1% on any requirements currently not covered by fixed-price contracts for the five-year period, 2004 through 2008, our total fuel expense would increase or decrease by $9 million and net income would increase or decrease by $5 million.

In the event of a significant change in coal prices, we would likely take actions to further mitigate our exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no change in our financial structure or fuel sources.

With regard to our exposure for commodity price risk for nuclear fuel, UE has fixed priced and base price with escalation agreements and/or inventories to fulfill its Callaway Nuclear Plant needs for uranium, conversion, enrichment, and fabrication services through 2006. UE expects to enter into additional contracts from time to time in order to supply nuclear fuel during the expected remainder of the life of the plant, at prices which cannot now be accurately predicted. UE's strategy is to hedge some of its three year requirements. This strategy permits optimum timing of new forward contracts given the relatively long price cycles in the nuclear fuel markets and provides security of supply to protect against unforeseen market disruptions. Unlike electricity and natural gas markets, there are no sophisticated financial instruments in nuclear fuel markets so most hedging is done via inventories and forward contracts.

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

With regard to our exposure to commodity price risk for purchased power and excess electricity sales, we have a subsidiary, Ameren Energy, whose primary responsibility includes managing market risks associated with changing market prices for electricity purchased and sold on behalf of UE and Genco. In addition, we have sold nearly all of our available non rate-regulated peak generation capacity for the summer of 2004 at various prices, the majority of which are fixed.

FAIR VALUE OF CONTRACTS

Most of our contracts qualify for treatment as normal purchases and normal sales. However, we utilize derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause:

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

The derivatives that we use to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. We continually assess our supply and delivery commitment positions against forward market prices and internally-forecasted forward prices and modify our exposure to market, credit and operational risk by entering into various offsetting transactions. In general, we believe these transactions serve to reduce our price risk. See Note 9 – Derivative Financial Instruments to our financial statements for further information.

The following table presents the favorable (unfavorable) changes in the fair value of all contracts marked-to-market during the year ended December 31, 2003:

Fair value of contracts at beginning of period, net	$ 7
Contracts realized or otherwise settled during the period	(10)
Changes in fair values attributable to changes in valuation technique and assumptions	–
Fair value of new contracts entered into during the period	–
Other changes in fair value	15
Fair value of contracts outstanding at end of period, net	$ 12

The following table presents maturities of contracts as of December 31, 2003:

Sources of Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value (a)
Prices actively quoted	$ 4	$–	$ –	$–	$4
Prices provided by other external sources (b)	3	–	–	–	3
Prices based on models and other valuation methods (c)	3	5	(3)	–	5
Total	$10	$5	$(3)	$–	$12

(a) Contracts of less than $1 million were with non-investment-grade rated counterparties.

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

(c) Principally coal and SO_2 option values based on a Black-Scholes model that includes information from external sources and our estimates. Also includes power forward contract values based on our estimates.

Forward-Looking Statements

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

- the closing and timing of Ameren's acquisition of Illinois Power and the impact of any conditions imposed by regulators in connection with their approval thereof;
- the effects of the stipulation and agreement relating to the UE Missouri electric excess earnings complaint case and other regulatory actions, including changes in regulatory policy;
- changes in laws and other governmental actions, including monetary and fiscal policy;
- the impact on the company of current regulations related to the opportunity for customers to choose alternative energy suppliers in Illinois;
- the effects of increased competition in the future due to, among other things, deregulation of certain aspects of 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;
- the availability of fuel for the production of electricity, such as coal and natural gas, and purchased power and natural gas for distribution, and the level and volatility of future market prices for such commodities, including the ability to recover any increased costs;
- the use of financial and derivative instruments;
- average rates for electricity in the Midwest;
- business and economic conditions;
- the impact of the adoption of new accounting standards and the application of appropriate technical accounting rules and guidance;
- interest rates and the availability of capital;
- actions of ratings agencies and the effects of such actions; weather conditions; generation plant construction, installation and performance; operation of nuclear power facilities and decommissioning costs;
- the effects of strategic initiatives, including acquisitions and divestitures;
- the impact of current environmental regulations on utilities and generating companies and the expectation that more stringent requirements will be introduced over time, which could potentially have a negative financial effect;
- future wages and employee benefits costs, including changes in returns on benefit plan assets;
- disruptions of the capital markets or other events making the company's access to necessary capital more difficult or costly;
- competition from other generating facilities, including new facilities that may be developed;
- difficulties in integrating CILCO and Illinois Power with Ameren's other businesses;
- changes in the coal markets, environmental laws or regulations, or other factors adversely impacting synergy assumptions in connection with the CILCORP and Illinois Power acquisitions;
- 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.

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