

Consolidated Notes to Financial Statements

December 31, 2003

Note 1 – Summary of Significant Accounting Policies

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. Also see 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. UE was incorporated in Missouri in 1922 and is successor to a number of companies, the oldest of which was organized in 1881. It is the largest electric utility in the State of Missouri and supplies electric and gas service to a 24,500 square mile area located in central and eastern Missouri and west central Illinois. This area has an estimated population of 3 million and includes the greater St. Louis area. UE supplies electric service to approximately 1.2 million customers and natural gas service to approximately 130,000 customers. See Note 3 – Rate and Regulatory Matters for information regarding the proposed transfer in 2004 of UE's Illinois electric and natural gas transmission and distribution businesses to CIPS.
- CIPS, also known as Central Illinois Public Service Company, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. CIPS was incorporated in Illinois in 1902. It supplies electric and gas utility service to portions of central and southern Illinois having an estimated population of 1 million in an area of approximately 20,000 square miles. CIPS supplies electric service to approximately 325,000 customers and natural gas service to approximately 170,000 customers.
- Genco, also known as Ameren Energy Generating Company, operates a non rate-regulated electric generation business. Genco was incorporated in Illinois in March 2000, in conjunction with the Illinois Customer Choice Law. Genco commenced operations on May 1, 2000, when CIPS transferred its five coal-fired power plants representing in the aggregate approximately 2,860 megawatts of capacity and related liabilities to Genco at historical net book value. The transfer was made in exchange for a subordinated promissory note from Genco in the amount of \$552 million and shares of Genco's common stock. Since Genco commenced operations, it has acquired 25 CTs providing it a total installed generating capacity of approximately 4,749 megawatts as of December 31, 2003. Genco currently has no plans to develop additional capacity. Genco is a subsidiary of Development Company, a subsidiary of Ameren Energy Resources, which is a subsidiary of Ameren.

See Note 3 – Rate and Regulatory Matters for information regarding the proposed transfer in 2004 of Genco's CTs located in Pinckneyville and Kinmundy, Illinois to UE.

- 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. CILCO was incorporated in Illinois in 1913. It supplies electric and gas utility service to portions of central and east central Illinois in areas of approximately 3,700 and 4,500 square miles, respectively, with an estimated population of 1 million. CILCO supplies electric service to approximately 205,000 customers and natural gas service to approximately 210,000 customers. In October 2003, CILCO transferred its coal-fired plants and a CT facility, representing in the aggregate approximately 1,100 megawatts of electric generating capacity, to a wholly owned subsidiary, known as AERG, as a contribution in respect of all the outstanding stock of AERG and AERG's assumption of certain liabilities. The net book value of the transferred assets was approximately \$378 million and no gain or loss was recognized as the transaction was accounted for as a transfer between entities under common control. The transfer was made in conjunction with the Illinois Customer Choice Law. CILCORP was incorporated in Illinois in 1985.

Ameren has various other subsidiaries responsible for the short and long-term marketing of power, procurement of fuel, management of commodity risks and providing other shared services. Ameren also has a 60% ownership interest in EEI through UE, which owns 40%, and Resources Company, which owns 20%. Ameren consolidates EEI for financial reporting purposes.

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. January 2003 and prior year data for CILCORP and CILCO are not included in Ameren's consolidated totals. See Note 2 – Acquisitions for further information. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

In order to be more consistent with industry reporting trends, our Consolidated Statement of Income has been reclassified to present all income taxes as one line item. Previously, we reported a portion of our income taxes in Operating Expenses and a portion in Other Income and Deductions. This change results in our calculation of

Operating Income now being on a pre-tax basis with no effect on net income. Additionally, our Consolidated Balance Sheet presentation has been reformatted to change the order in which current and non-current items appear, with no effect on total assets, total liabilities or any sub-categories included on our Consolidated Balance Sheet.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates. Certain reclassifications have been made to prior years' financial statements to conform to 2003 reporting. See Accounting Changes and Other Matters relating to SFAS No. 143, "Accounting for Asset Retirement Obligations," below and Note 4 – Property and Plant, Net for further information.

REGULATION

Ameren is subject to regulation by the SEC. Certain of Ameren's subsidiaries are also regulated by the MoPSC, ICC, NRC and the FERC. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," we defer certain costs pursuant to actions of our regulators and are currently recovering such costs in rates charged to customers. See Note 3 – Rate and Regulatory Matters for further information.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash on hand and temporary investments purchased with an original maturity of three months or less. The restricted cash amount as of December 31, 2003, was \$5 million (2002 - \$5 million).

PROPERTY AND PLANT

We capitalize the cost of additions to, and betterments of, units of property and plant. The cost includes labor, material, applicable taxes and overhead. An allowance for funds used during construction, or the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to rate-regulated construction expenditures, is also added for our rate-regulated assets, and interest during construction is added for non rate-regulated assets. Maintenance expenditures and the renewal of items not considered units of property are expensed as incurred. When units of depreciable property are retired, the original costs, less salvage value, are charged to accumulated depreciation. Non rate-regulated asset removal costs which do not constitute legal obligations were expensed as incurred beginning in 2003. Rate-regulated asset removals which do not constitute legal obligations are classified as a regulatory liability. See Accounting Changes and Other Matters relating to SFAS No. 143, "Accounting for Asset Retirement Obligations," below and Note 4 – Property and Plant, Net for further information.

DEPRECIATION

Depreciation is provided over the estimated lives of the various classes of depreciable property by applying composite rates on a straight-line basis. The provision for depreciation for Ameren in 2003, 2002 and 2001 was approximately 3% of the average depreciable cost. Beginning in January 2003, with the adoption of SFAS No. 143, depreciation rates for our non rate-regulated assets were reduced to reflect the discontinuation of the accrual of dismantling and removal costs. See Accounting Changes and Other Matters relating to SFAS No. 143, "Accounting for Asset Retirement Obligations," below for further information.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

In our rate-regulated operations, we capitalize the allowance for funds used during construction, which is a utility industry accounting practice. Allowance for funds used during construction does not represent a current source of cash funds. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

Under accepted ratemaking practice, cash recovery of allowance for funds used during construction, as well as other construction costs, occurs when completed projects are placed in service and reflected in customer rates. The allowance for funds used during construction ranges of rates used were 3% - 4% during 2003, 5% - 9% during 2002 and 4% - 10% during 2001.

GOODWILL

Goodwill is the excess of the purchase price of an acquisition over the fair value of the net assets acquired. Under the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets," goodwill and other intangibles with indefinite lives are no longer subject to amortization. As required by SFAS No. 142, we evaluate goodwill for impairment in the fourth quarter annually or more frequently if events and circumstances indicate that the asset might be impaired. Ameren's goodwill relates to the acquisitions of CILCORP and Medina Valley in 2003. See Note 2 – Acquisitions for additional information regarding the acquisitions.

LEVERAGED LEASES

Certain Ameren subsidiaries own interests in assets which have been financed as a leveraged lease. Ameren's investment in these leveraged leases represents the equity portion, generally 20% of the total investment, either as an undivided interest in the equipment or as a part owner through a partnership. In accordance with SFAS No. 13, "Accounting for Leases," at the time of lease inception a debit for rents receivable and estimated residual value is recorded with a credit to unearned income. These amounts are then adjusted over time as rents are received, income is realized and the asset is eventually sold. Ameren accounts for these investments as a net investment in these assets and does not include the amount of outstanding debt since the third party debt is non-recourse to the Ameren subsidiaries.

IMPAIRMENT OF LONG-LIVED ASSETS

We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared with the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for loss if the carrying value is greater than the fair value.

UNAMORTIZED DEBT DISCOUNT, PREMIUM AND EXPENSE

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

REVENUE

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

Interchange revenues included in Operating Revenues – Electric were \$351 million for the year ended December 31, 2003 (2002 - \$259 million; 2001 - \$364 million). See EITF No. 02-3 discussion under Accounting Changes and Other Matters below for further information.

PURCHASED POWER

Purchased power included in Operating Expenses – Fuel and Purchased Power was \$256 million for the year ended December 31, 2003 (2002 - \$167 million; 2001 - \$298 million). See EITF No. 02-3 discussion under Accounting Changes and Other Matters below for further information.

FUEL AND GAS COSTS

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

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

EXCISE TAXES

Excise taxes reflected on Missouri electric and gas, and Illinois gas, customer bills are imposed on us and are recorded gross in Operating Revenues and Other Taxes. Excise taxes recorded in Operating Revenues and Taxes Other than Income Taxes for 2003 were \$137 million (2002 - \$116 million; 2001 - \$113 million). Excise taxes reflected on Illinois electric customer bills are imposed on the consumer and are recorded as tax collections payable and included in Taxes Accrued on the Consolidated Balance Sheet.

INCOME TAXES

We file a consolidated federal tax return. Deferred tax assets and liabilities are recognized for the tax consequences of transactions that

have been treated differently for financial reporting and tax return purposes, measured using statutory tax rates.

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the related properties.

EARNINGS PER SHARE

There were no differences between the basic and diluted earnings per share amounts for Ameren in 2003. The inclusion of assumed stock option conversions in the calculation of earnings per share resulted in dilution of \$0.01 for 2002 and 2001. The dilutive component in each of the periods was comprised of assumed stock option conversions, which increased the number of shares outstanding in the diluted earnings per share calculation by 289,244 in 2003, 332,909 shares in 2002 and 331,813 shares in 2001. Ameren's equity security units have no dilutive effect on our earnings per share, except during periods when the average market price of Ameren's common stock is above \$46.61.

ACCOUNTING CHANGES AND OTHER MATTERS

SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activities"

In January 2001, we adopted SFAS No. 133. The impact of that adoption resulted in a cumulative effect charge of \$7 million, net of taxes, to the Consolidated Statement of Income, and a cumulative effect adjustment of \$11 million, net of taxes, to Accumulated OCI, which reduced common stockholders' equity. See Note 9 – Derivative Financial Instruments for further information.

SFAS No. 143 – "Accounting for Asset Retirement Obligations"

We adopted the provisions of SFAS No. 143, effective January 1, 2003. SFAS No. 143 provides the accounting requirements for asset retirement obligations associated with tangible, long-lived assets. SFAS No. 143 requires us to record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and to capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value. Corresponding increases in asset book values are depreciated over the remaining useful life of the related asset. Uncertainties as to the probability, timing or amount of cash flows associated with an asset retirement obligation affect our estimates of fair value.

Upon adoption of this standard, Ameren recognized additional asset retirement obligations of approximately \$213 million and a net increase in net property and plant of approximately \$77 million related primarily to UE's Callaway Nuclear Plant decommissioning costs and retirement costs for a UE river structure. The difference between the net asset and the liability recorded upon adoption of SFAS No. 143 related to rate-regulated assets was recorded as an additional regulatory asset of approximately \$136 million because Ameren expects to continue to recover in electric rates the cost of Callaway Nuclear Plant

decommissioning and other costs of removal. These asset retirement obligations and associated assets are in addition to assets and liabilities of \$174 million that UE had recorded prior to the adoption of SFAS No. 143, related to the future obligations and funds accumulated to decommission the Callaway Nuclear Plant.

Also upon adoption of this standard, Ameren recognized an asset retirement obligation of approximately \$4 million and a net increase in net property and plant of approximately \$34 million. The asset retirement obligation relates to retirement costs for a Genco power plant ash pond. The net increase in property and plant, as well as the majority of the net after-tax gain of \$18 million recognized upon adoption, resulted from the elimination of costs of removal for non rate-regulated assets previously accrued as a component of accumulated depreciation that were not legal obligations (\$20 million). Ameren also recognized a loss for the difference between the net asset and liability for the retirement obligation recorded upon adoption related to Genco's assets (\$2 million).

As a result of the acquisition of CILCORP on January 31, 2003, Ameren's asset retirement obligations increased due to the assumption of asset retirement obligations of approximately \$6 million related to CILCO's power plant ash ponds (now owned by AERG).

Asset retirement obligations at Ameren increased by \$22 million during the year ended December 31, 2003, to reflect the accretion of obligations to their present value. Substantially all of this accretion was recorded as an increase to regulatory assets.

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

The fair value of the nuclear decommissioning trust fund for UE's Callaway Nuclear Plant is reported in Nuclear Decommissioning Trust Fund in Ameren's Consolidated Balance Sheet. This amount is legally restricted to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory asset recorded in connection with the adoption of SFAS No. 143.

SFAS No. 143 required a change in the depreciation methodology we historically utilized for our non rate-regulated operations. Historically, we included an estimated cost of dismantling and removing plant from service upon retirement in the basis upon which our depreciation rates were determined. SFAS No. 143 required us to exclude costs of dismantling and removal upon retirement from the depreciation rates applied to non rate-regulated plant balances. Further, we were required to remove accumulated provisions for dismantling and removal costs from accumulated depreciation, where they were embedded, and to reflect such adjustment as a gain upon adoption of this standard, to the extent such dismantling and removal activities were not considered legal

asset retirement obligations as defined by SFAS No. 143. The elimination of costs of removal from accumulated depreciation resulted in a gain for a change in accounting principle at Ameren, as noted above, of \$20 million, net of taxes. Beginning in January 2003, depreciation rates for non rate-regulated assets were reduced to reflect the discontinuation of the accrual of dismantling and removal costs. In addition, non rate-regulated asset removal costs will prospectively be expensed as incurred. The impact of this change in accounting results in a decrease in depreciation expense and an increase in operations and maintenance expense, the net impact of which is indeterminable, but not expected to be material.

Like the methodology employed by our non rate-regulated operations, the depreciation methodology historically utilized by our rate-regulated operations has included an estimated cost of dismantling and removing plant from service upon retirement. Because these estimated costs of removal have been included in the cost of service upon which our present utility rates are based, and with the expectation that this practice will continue in the jurisdictions in which we operate, adoption of SFAS No. 143 did not result in any change in the depreciation accounting practices of our rate-regulated operations and, therefore, had no impact on net income from rate-regulated operations. However, in accordance with SFAS No. 143, estimated future removal costs previously embedded in accumulated depreciation were classified as a regulatory liability at December 31, 2003. A corresponding reclassification was made to conform the December 31, 2002, Consolidated Balance Sheet to the current year presentation. These reclassifications had no impact on our results of operations or cash flows. The estimated future removal costs recognized as a regulatory liability were \$694 million and \$652 million at December 31, 2003 and 2002, respectively.

The following table presents the asset retirement obligation as though SFAS No. 143 had been in effect for 2001 and 2002:

Pro Forma Asset Retirement Obligation

January 1, 2001	\$350
December 31, 2001	370
December 31, 2002	391

Pro forma net income, as well as pro forma earnings per share for Ameren, has not been presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS No. 143 to prior periods would result in pro forma net income not materially different from the actual amounts reported for these periods.

EITF Issue No. 02-3, EITF Issue No. 98-10 and EITF Issue No. 03-11

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. Prior to adopting EITF No. 02-3 and the rescission of EITF No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," our accounting practice was to present all settled energy purchase or sale contracts within our power risk management program on a gross basis in Operating Revenues – Electric and Other and in Operating Expenses – Fuel and Purchased Power and Other Operations and Maintenance. This meant that revenues were recorded for the sum of the notional amounts of the power sales contracts with a corresponding charge to income for the costs of the energy that was generated, or for the sum of the notional amounts of a purchased power contract.

In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. The effective date for the full rescission of EITF No. 98-10 was for fiscal periods beginning after December 15, 2002, with early adoption permitted. In addition, the EITF reached a consensus in October 2002, that all SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," trading derivatives (subsequent to the rescission of EITF No. 98-10) should be shown net in the income statement, whether or not physically settled. This consensus applies to all energy and non-energy related trading derivatives that meet the definition of a derivative pursuant to SFAS No. 133. The operating revenues and costs that were netted for the years ended December 31, 2002 and 2001, which reduced Operating Revenues - Electric and Other, and Operating Expenses – Fuel and Purchased Power and Other Operations and Maintenance by equal amounts were \$738 million and \$648 million, respectively.

The adoption of EITF No. 02-3, the rescission of EITF No. 98-10 and the related transition guidance resulted in the netting of energy contracts for financial reporting purposes, which lowered our reported revenues and costs with no impact on earnings.

In July 2003, the EITF reached a consensus on EITF No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, 'Accounting for Derivative Instruments and Hedging Activities,' and Not Held for Trading Purposes as Defined in 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 was ratified by the FASB in August 2003. The EITF concluded that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The adoption of EITF No. 03-11 will have no impact on our results of operations.

SFAS No. 148 – "Accounting for Stock-based Compensation – Transition and Disclosure"

In December 2002, the FASB issued SFAS No. 148. SFAS No. 148 amended SFAS No. 123, "Accounting for Stock-based Compensation," to provide alternative methods of transition for an entity that voluntarily changes to the fair value-based method

of accounting for stock-based employee compensation. It also amended the disclosure provisions to require disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation.

Prior to 2003, we accounted for stock options granted under long-term incentive plans under the recognition and measurement provisions of APB Opinion No. 25, "Accounting for Stock Issued to Employees." No stock-based employee compensation cost was recognized for options under Ameren's plan in 2002 and 2001, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The pre-tax cost based on the weighted-average grant-date fair value of options for Ameren would have been approximately \$2 million in each of the years ended 2002 and 2001 had the fair value method under SFAS No. 123 been used for options granted. Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS No. 123 by using the prospective method of adoption under SFAS No. 148. As no stock options have been issued under the Ameren plan since 2001, SFAS No. 148 did not have any effect on Ameren's financial position, results of operations or liquidity since adoption. See also Note 12 – Stock-based Compensation for further information.

SFAS No. 149 – "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

In April 2003, the FASB issued SFAS No. 149. SFAS No. 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," for decisions made by the Derivative Implementation Group, as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for reporting periods beginning before June 15, 2003, which continue to be applied based on their original effective dates. SFAS No. 149 did not have any effect on our financial position, results of operations or liquidity upon adoption in the third quarter of 2003.

SFAS No. 150 – "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

In May 2003, the FASB issued SFAS No. 150 that established standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. Among other things, SFAS No. 150 requires financial instruments that were issued in the form of shares with an unconditional obligation to redeem the instrument by transferring assets on a specified date, to be classified as liabilities. Accordingly, SFAS No. 150 requires issuers to classify mandatorily redeemable financial instruments as liabilities. SFAS No. 150 also requires such financial instruments to be measured at fair value and a cumulative effect adjustment to be recognized in the Consolidated

Statement of Income for any difference between the carrying amount and fair value. SFAS No. 150 became effective July 1, 2003. At July 1, 2003, Ameren had \$21 million of preferred stock subject to mandatory redemption, which was reclassified to the liability section of Ameren's Consolidated Balance Sheet. This preferred stock is redeemable at par at any time, and therefore, it was estimated there was no difference between book value and fair value.

FIN No. 46 – “Consolidation of Variable Interest Entities”

In January 2003, the FASB issued FIN No. 46, which significantly changed the consolidation requirements for traditional special purpose entities (SPE) and certain other entities and addressed the consolidation of variable-interest entities (VIEs). The primary objective of FIN No. 46 was to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights. If an entity absorbs the majority of the VIEs' expected losses or receives a majority of the VIEs' expected residual returns, or both, it must consolidate the VIE.

Initially, FIN No. 46 was effective no later than the beginning of the first interim period after June 15, 2003, for VIEs created before February 1, 2003. For VIEs created after January 31, 2003, FIN No. 46 was effective immediately. In September 2003, the FASB deferred the effective date of FIN No. 46 until the end of the first interim or annual period ending after December 15, 2003 for VIEs created prior to January 31, 2003. In December 2003, the FASB further deferred this effective date of FIN No. 46 for non-SPEs until the end of the first interim or annual period ending after March 15, 2004. During these deferral periods, the FASB has continued to clarify and amend several provisions, much of which will assist in the application of FIN No. 46 to operating entities. Ameren does not have any interests in entities that are considered SPEs. In addition, FIN No. 46 requires the deconsolidation of certain trust-preferred arrangements; however, Ameren does not have any trust-preferred arrangements.

Ameren is continuing to evaluate the impact of FIN No. 46 for non-SPEs. Ameren has several leveraged leases and other investments that we currently do not consolidate. We are still evaluating the impact of adopting FIN No. 46 in our first quarter ended March 31, 2004.

SFAS No. 132 (revised 2003) – “Employers’ Disclosures about Pensions and Other Postretirement Benefits”

In December 2003, the FASB issued SFAS No. 132 (revised) to improve financial statement disclosures for defined benefit plans. The standard requires more details about plan assets, benefit obligations, cash flows, benefit costs and other relevant information. SFAS No. 132 (revised) became effective for fiscal years ending after December 15, 2003. See Note 11 – Retirement Benefits for further information.

FASB Staff Position SFAS No. 106-1 – “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003”

Through its postretirement benefit plans, Ameren provides retirees with prescription drug coverage. On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Prescription Drug Act) was enacted. The Prescription Drug Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree healthcare benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. In response to the enactment of the Prescription Drug Act, the FASB issued FASB Staff Position SFAS No. 106-1 in January 2004, which permits a plan sponsor of a postretirement healthcare plan that provides a prescription drug benefit to make a one-time election to defer the accounting for the effects of the Prescription Drug Act. Ameren has made this one-time election allowed by FASB Staff Position SFAS No. 106-1. Thus, any measures of the accumulated projected benefit obligation or net periodic postretirement benefit costs in Ameren's financial statements and included in Note 11 – Retirement Benefits do not reflect the effects of the Prescription Drug Act on Ameren's postretirement plans. Ameren is evaluating what impact the Prescription Drug Act will have on its postretirement benefit plans and whether it will be eligible for a federal subsidy beginning in 2006. Specific authoritative guidance on the accounting for the federal subsidy is pending.

Note 2 – 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 from AES 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. See Note 1 – Summary of Significant Accounting Policies for further information on the presentation of the results of CILCORP and CILCO in Ameren's consolidated financial statements.

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 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.

The following table presents the estimated fair values of the assets acquired and liabilities assumed at the dates of our acquisitions of CILCORP and Medina Valley. A third party valuation of acquired property and plant and intangible assets is substantially complete; however, the allocation of the purchase price is subject to refinement until the valuation is finalized.

Current assets	\$ 315
Property and plant	1,169
Investments and other non-current assets	154
Specifically-identifiable intangible assets	6
Goodwill	568
Total assets acquired	2,212
Current liabilities	196
Long-term debt, including current maturities	937
Other non-current liabilities	521
Total liabilities assumed	1,654
Preferred stock assumed	41
Net assets acquired	\$ 517

Specifically-identifiable intangible assets of \$6 million are comprised of retail customer contracts, which are subject to amortization with an average life of 10 years.

Goodwill of \$568 million (CILCORP - \$561 million; Medina Valley - \$7 million) was recognized in connection with the CILCORP and Medina Valley acquisitions. None of this goodwill is expected to be deductible for tax purposes.

The following unaudited pro forma financial information presents a summary of Ameren's consolidated results of operations for the years ended December 31, 2003 and 2002, assuming the acquisitions of CILCORP and Medina Valley had been completed at the beginning of fiscal year 2002, including pro forma adjustments, which are based upon preliminary estimates, to reflect the allocation of the purchase price to the acquired net assets.

	2003	2002
Operating revenues	\$4,694	\$4,605
Income before cumulative effect of change in accounting principle	510	410
Cumulative effect of change in accounting principle, net of taxes	22	–
Net income	\$ 532	\$ 410
Earnings per share - basic	\$ 3.29	\$ 2.60
- diluted	\$ 3.29	\$ 2.59

This pro forma information is not necessarily indicative of the results of operations as they would have been had the transactions been effected on the assumed date, nor is it an indication of trends in future results.

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. Illinois Power also files quarterly and annual reports with the SEC.

Note 3 – Rate and Regulatory Matters

INTERCOMPANY TRANSFER OF ELECTRIC GENERATING FACILITIES AND ILLINOIS SERVICE TERRITORY

As a part of the settlement of the Missouri electric rate case in 2002, UE committed to making certain infrastructure investments from January 1, 2002 through June 30, 2006, including the addition of 700 megawatts of generation capacity. The new capacity requirement is expected to be satisfied by the additions in 2002 of 240 megawatts and the proposed transfer from Genco to UE, at net book value (approximately \$250 million), of approximately 550 megawatts of CTs at Pinckneyville and Kinmundy, Illinois. The transfer is subject to receipt of FERC and SEC approval. Approval by the MoPSC is not required in order for this transfer to occur. However, the MoPSC has jurisdiction over UE's ability to recover the cost of the transferred generating facilities from its electric customers in its rates. As part of the settlement of the Missouri electric rate case in 2002, UE is subject to a rate moratorium providing for no changes in its electric rates before June 30, 2006, subject to certain statutory and other exceptions. Approval of the ICC is not required contingent upon prior approval and execution of UE's transfer of its Illinois public utility operations to CIPS as discussed below.

In February 2003, UE sought approval from the FERC to transfer approximately 550 megawatts of generating assets from Genco to UE. Certain independent power producers objected to UE's request based on a claim that the transfer may harm competition for the sale of electricity at wholesale and the FERC set the matter for hearing. In February 2004, the Administrative Law Judge hearing the case issued a preliminary order supporting the transfer. However, the full commission must approve the order for it to become effective.

In May 2003, UE announced its plan to limit its public utility operations to the state of Missouri and to discontinue operating as a public utility subject to ICC regulation. UE intends to accomplish this plan by transferring its Illinois-based electric and natural gas businesses, including its Illinois-based distribution assets and certain of its transmission assets, to CIPS. In 2003, UE's Illinois electric and gas service territory generated revenues of \$155 million and

had a net book value of \$122 million at December 31, 2003. UE's electric generating facilities and a certain minor amount of its electric transmission facilities in Illinois would not be part of the transfer. The transfer was approved by the FERC in December 2003. The transfer of UE's Illinois-based utility businesses will also require the approval of the ICC, the MoPSC and the SEC under the provisions of the PUHCA. In August 2003, UE filed with the MoPSC, and in October and November 2003, filed with the ICC and the SEC for authority to transfer UE's Illinois-based utility businesses, at net book value, to CIPS. The filing with the ICC seeks approval to transfer only UE's Illinois-based natural gas utility business since the ICC authorized the transfer of UE's Illinois-based electric utility business to CIPS in 2000.

A filing seeking approval of both the transfer of UE's Illinois-based utility business and Genco's CTs was made with the SEC in October 2003. If completed, the transfers will be accounted for at book value with no gain or loss recognition, which is appropriate treatment for transactions of this type by two entities under common control. In January 2004, the MoPSC staff and the Missouri Office of Public Counsel filed rebuttal testimony with the MoPSC expressing concerns that the transfer may be detrimental to the public in Missouri and recommended that the transfer be denied. UE will have an opportunity to address these concerns in surrebuttal testimony.

We are unable to predict the ultimate outcome of these regulatory proceedings or the timing of the final decisions of the various agencies.

MISSOURI ELECTRIC

MoPSC Rate Case

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

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

- The phase-in of \$110 million of electric rate reductions through April 2004, \$50 million of which was retroactively effective as of April 1, 2002, \$30 million of which became effective on April 1, 2003, and \$30 million of which will become effective on April 1, 2004.
- A rate moratorium providing for no changes in rates before June 30, 2006, subject to certain statutory and other exceptions.

- A commitment to contribute \$14 million to programs for low income energy assistance and weatherization, promotion of energy efficiency and economic development in UE's service territory in 2002, with additional payments of \$3 million made annually on June 30, 2003 through June 30, 2006. This entire obligation was expensed in 2002.
- A commitment to make \$2.25 billion to \$2.75 billion in critical energy infrastructure investments from January 1, 2002 through June 30, 2006, including, among other things, the addition of more than 700 megawatts of new generation capacity and the replacement of steam generators at UE's Callaway Nuclear Plant. The 700 megawatts of new generation is expected to be satisfied by 240 megawatts that were added by UE in 2002 and the proposed transfer at net book value to UE of approximately 550 megawatts of generation assets from Genco, which is subject to receipt of necessary regulatory approvals. See Intercompany Transfer of Electric Generating Facilities and Illinois Service Territory within this Note for additional information on the proposed transfer.
- An annual reduction in UE's depreciation rates by \$20 million, retroactive to April 1, 2002, based on an updated analysis of asset values, service lives and accumulated depreciation levels.
- A one-time credit of \$40 million which was accrued during the plan period. The entire amount was paid to UE's Missouri retail electric customers in 2002 for settlement of the final sharing period under the alternative regulation plan that expired June 30, 2001.

Marketing Company – UE Power Supply Agreements

In order to satisfy UE's regulatory load requirements for 2001, UE purchased, under a one year contract, 450 megawatts of capacity and energy from Marketing Company. For 2002, UE similarly entered into a one year contract with Marketing Company for the purchase of 200 megawatts of capacity and energy. The MoPSC objected to these contracts before the SEC under the PUHCA and the FERC. In 2002 and 2003, respectively, the FERC approved a settlement modifying future procedures for entering into affiliate contracts and the MoPSC withdrew its complaint at the SEC. As a result, no additional action by the FERC or the SEC is expected in this matter.

FEDERAL – ELECTRIC TRANSMISSION

Regional Transmission Organization

In December 1999, the FERC issued Order 2000 requiring all utilities subject to FERC jurisdiction to state their intentions for joining a RTO. Since April 2002, the GridAmerica Companies have participated in a number of filings at the FERC in an effort to form GridAmerica LLC, or GridAmerica, as an ITC. On December 19, 2002, the FERC issued an order conditionally approving the formation and operation of GridAmerica as an ITC within the Midwest ISO subject to further compliance filings, which were made by the GridAmerica Companies in early 2003. CILCO is already a member of the Midwest ISO and

has transferred functional control of its transmission system to the Midwest ISO. Transmission service on the CILCO transmission system is provided pursuant to the terms and conditions of the Midwest ISO OATT on file with the FERC.

On April 30, 2003, the FERC issued an order authorizing the GridAmerica Companies' request to transfer functional control of their transmission assets to GridAmerica. The FERC also accepted the proposed rate amendments to the Midwest ISO OATT, filed in early 2003 by Midwest ISO and the GridAmerica Companies, effective upon the commencement of service over the GridAmerica transmission facilities under the Midwest ISO OATT, suspended the proposed rates for a nominal period, subject to refund, and established hearing and settlement judge procedures to determine the justness and reasonableness of the proposed rate amendments to the Midwest ISO OATT. In August 2003, the GridAmerica Companies filed acknowledgements with the FERC to permit GridAmerica to commence operations on October 1, 2003, on a phased basis, by assuming, with the Midwest ISO, functional control of the transmission systems of American Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp., and Northern Indiana Public Service Company, a subsidiary of NiSource Inc. Pursuant to this authorization, GridAmerica began operating on October 1, 2003.

Also beginning on October 1, 2003, the proposed rates filed by Midwest ISO and the GridAmerica Companies became effective, subject to refund for FirstEnergy Corp. and NiSource Inc. Since UE and CIPS have not transferred functional control of their transmission assets to Midwest ISO, the proposed rates are not effective for UE or CIPS. Efforts to settle the disputed rate issues concerning rates for transmission service over the transmission assets of the GridAmerica Companies are continuing. UE's participation in GridAmerica is pending before the MoPSC for approval. On February 6, 2004, UE filed a Stipulation and Agreement with the MoPSC, that if approved by the MoPSC, would authorize UE's participation in the Midwest ISO through GridAmerica for a five year period.

If UE secures approval to participate in GridAmerica from the MoPSC, and UE and CIPS transfer functional control of their transmission systems to GridAmerica, the FERC has ordered the return, with interest, of the \$13 million exit fee paid by UE and the \$5 million exit fee paid by CIPS when they previously left the Midwest ISO.

Genco does not own transmission assets, but pays UE and CIPS for the use of their transmission systems to transmit power from the Genco generating plants. Until the tariffs and other material terms of UE's and CIPS' participation in GridAmerica and GridAmerica's participation in the Midwest ISO are finalized and approved by the FERC and other regulatory authorities having jurisdiction, we are unable to predict the ultimate impact that ongoing RTO developments will have on our financial position, results of operations or liquidity.

On November 17, 2003, the FERC issued a final order upholding an earlier order issued in July 2003 (July Order), that will reduce UE's and CIPS', as well as other transmission-owning utilities, "through and out" transmission revenues effective April 1, 2004, subject to certain

conditions. The revenues subject to elimination by this order are those revenues from transmission reservations that travel through or out of our transmission systems and are also used to provide electricity to load within the Midwest ISO or PJM Interconnection LLC systems. The magnitude of the potential net revenue reduction resulting from this order could be up to \$20 to \$25 million annually if UE and CIPS are not in a RTO. While it is anticipated that our transmission revenues could be reduced by these orders, transmission expenses for our affiliates could be reduced. Moreover, the FERC's final Order explicitly permits companies to collect the lost "through and out" revenues through other transitional rate mechanisms. Until it is determined when, or if, UE and CIPS will join a RTO, or the magnitude of lost "through and out" transmission revenue recovery we will receive through other rate mechanisms, we are unable to predict the ultimate impact of these orders.

Standard Market Design Notice of Proposed Rulemaking

In July 2002, the FERC issued its Standard Market Design NOPR. The NOPR proposes a number of changes to the way the current wholesale transmission service and energy markets are operated. Specifically, the NOPR proposes that all jurisdictional transmission facilities be placed under the control of an independent transmission provider (similar to a RTO), proposes a new transmission service tariff that provides a single form of transmission service for all users of the transmission system including bundled retail load, and proposes a new energy market and congestion management system that uses locational marginal pricing as its basis. In our initial comments on the NOPR, which were filed at the FERC on November 15, 2002, we expressed our concern with the potential impact of the proposed rules in their current form on the cost and reliability of service to retail customers. We also proposed that certain modifications be made to the proposed rules in order to protect transmission owners from the possibility of trapped transmission costs that might not be recoverable from ratepayers as a result of inconsistent regulatory policies. We filed additional comments on the remaining sections of the NOPR during the first quarter of 2003.

In April 2003, the FERC issued a "white paper" reflecting comments received in response to the NOPR. More specifically, the white paper indicated that the FERC will not assert jurisdiction over the transmission rate component of bundled retail service and will insure that existing bundled retail customers retain their existing transmission rights and retain rights for future load growth in its final rule. Moreover, the white paper acknowledged that the final rule will provide the states with input on resource adequacy requirements, allocation of firm transmission rights, and transmission planning. The FERC also requested input on the flexibility and timing of the final rule's implementation.

Although issuance of the Standard Market Design final rule is uncertain and the implementation schedule is still unknown, the Midwest ISO is already in the process of implementing a separate market design similar to the proposed market design in the NOPR. In July 2003, the Midwest ISO filed with the FERC a revised OATT

codifying the terms and conditions under which it would implement the new market design. Thereafter, on October 17, 2003, the Midwest ISO filed a motion for withdrawal of their revised OATT to ensure that effective reliability tools are in place and operating correctly before moving forward with the new market design. We will continue monitoring the status of the Midwest ISO's market design and the potential impact of the market design on the cost and reliability of service to retail customers and providing guidance to be followed by the Midwest ISO in developing a new energy market design in the future. Until the FERC issues a final rule and the Midwest ISO finalizes its new market design, we are unable to predict the ultimate impact of the NOPR or the Midwest ISO new market design on our future financial position, results of operations or liquidity.

FEDERAL — HYDROELECTRIC

In February 2004, UE filed an application with the FERC to renew the license for its Osage hydroelectric plant for an additional 50 year term. The current FERC license expires on February 28, 2006. The license application proposes to continue operations at the Osage plant as a peaking facility, upgrade four turbine units and to maximize the hydroelectric capacity of the plant.

ILLINOIS ELECTRIC

In 2002, all of our Illinois residential, commercial and industrial customers had a choice in electric suppliers under the provisions of 1997 Illinois legislation related to the restructuring of the Illinois electric industry (the Illinois Customer Choice Law). Under the Illinois Customer Choice Law, rates initially were frozen through January 1, 2005, subject to residential electric rate decreases of up to 5% in 2002 to the extent rates exceeded the Midwest utility average. In 2002, our Illinois electric rates were below the Midwest utility average.

As the result of an amendment to the Illinois Customer Choice Law, the rate freeze was extended through January 1, 2007. As a result of this extension, CIPS and Marketing Company expect to seek to renew or extend their power supply agreement and CILCO and AERG expect to seek to renew or extend their power supply agreement through January 1, 2007. A renewal or extension of the power supply agreements will depend on compliance with regulatory requirements in effect at the time.

The Illinois Customer Choice Law allows a utility to collect transition charges from customers that elect to move from bundled retail rates to market-based power and energy. Utilities have the right to collect applicable transition charges throughout the transition period that ends January 1, 2007, from customers that elect market-based power and energy. In the order authorizing the acquisition of CILCO by Ameren, the ICC required UE, CIPS and CILCO to eliminate transition charges in the period commencing June 2003, through at least May 2005. The non-recovery of transition charges is not expected to have a material impact on UE, CIPS or CILCO.

The Illinois Customer Choice Law also contains a provision requiring that one-half of excess earnings from the Illinois jurisdiction for the years 1998 through 2006 be refunded to UE, CIPS and CILCO's

Illinois customers. Excess earnings are defined as the portion of the two-year average annual rate of return on common equity in excess of 1.5% of the two-year average of the Index, as defined in the Illinois Customer Choice Law. The Index is defined as the sum of the average for the twelve months ended September 30 of the average monthly yields of the Treasury long-term average (25 years and above), plus 7% for both UE and CIPS and 11% for CILCO. Estimated refunds totaling less than \$1 million to UE's Illinois customers are expected to be made during the period from April 1, 2004 through March 31, 2005. No refunds to CIPS' or CILCO's Illinois customers are expected to be made during the period from April 1, 2004 through March 31, 2005, resulting from excess earnings during the year ended December 31, 2003. UE made excess earnings refunds of \$2.1 million during the period April 1, 2000 through March 31, 2001, resulting from excess earnings during the year ended December 31, 1999. Additionally, UE made excess earnings refunds of \$1.5 million during the period April 1, 2001 through March 31, 2002, resulting from excess earnings during the year ended December 31, 2000. These refunds were recorded as a reduction to Operating Revenues – Electric.

ILLINOIS GAS

In October 2003, the ICC issued orders awarding CILCO, CIPS and UE increases in annual natural gas delivery rates of approximately \$9 million, \$7 million and \$2 million, respectively. These new rates went into effect in November 2003.

MISSOURI GAS

In January 2004, a stipulation and agreement resolving a request by UE to increase annual natural gas rates became effective following agreement by all parties to the case and approval by the MoPSC. The stipulation and agreement authorized an increase in annual gas delivery rates of approximately \$13 million, effective February 15, 2004. Other principal features of the stipulation and agreement include:

- A rate moratorium providing for no changes in gas delivery rates before July 1, 2006, absent the occurrence of a significant, unusual event that has a major impact on UE.
- An agreement not to request a PGA increase prior to April 1, 2004.
- A commitment to make \$15 million to \$25 million in infrastructure improvement investments from July 1, 2003 through December 31, 2006, including replacement of cast iron main and unprotected steel service lines. UE agreed not to propose rate adjustments to recover infrastructure costs through a statutory infrastructure system replacement surcharge prior to January 1, 2006.
- Commitments to contribute an aggregate of \$310,000 annually to programs for low income weatherization, energy assistance and energy efficient equipment in UE's service territory.

REGULATORY ASSETS AND LIABILITIES

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

The following table presents our regulatory assets and regulatory liabilities at December 31, 2003 and 2002:

	2003	2002
Regulatory assets:		
Income taxes ^{(a)(b)}	\$431	\$526
Asset retirement obligation ^{(b)(c)}	122	–
Callaway costs ^(d)	77	81
Unamortized loss on reacquired debt ^{(b)(e)}	46	32
Recoverable costs –		
contaminated facilities ^{(b)(f)}	27	26
Other ^{(b)(g)}	26	25
Total regulatory assets	\$729	\$690
Regulatory liabilities:		
Income taxes ^(h)	\$127	\$136
Removal costs ⁽ⁱ⁾	694	652
Total regulatory liabilities	\$821	\$788

(a) Amount represents SFAS No. 109 deferred tax asset. See Note 13 – Income Taxes for amortization period.

(b) These assets do not earn a return.

(c) Represents recoverable costs for asset retirement obligations at our rate-regulated operations. See SFAS No. 143 discussion in Note 1 – Summary of Significant Accounting Policies.

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

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

(f) Represents the recoverable portion of accrued environmental site liabilities which is primarily collected from electric and gas customers through ICC approved revenue riders in Illinois.

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

(h) Represents unamortized portion of investment tax credit and federal excess taxes. See Note 13 – Income Taxes for amortization period.

(i) Represents estimated funds collected for the eventual dismantling and removing plant from service upon retirement related to our rate-regulated operations. See SFAS No. 143 discussion in Note 1 – Summary of Significant Accounting Policies.

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

Note 4 – Property and Plant, Net

The following table presents property and plant, net at December 31, 2003 and 2002:

	2003	2002
Property and plant, at original cost:		
Electric	\$16,050	\$14,421
Gas	743	557
Other	211	219
	17,004	15,197
Less accumulated depreciation and amortization	6,594	6,179
	10,410	9,018
Construction work in progress:		
Nuclear fuel in process	66	81
Other	441	393
Property and plant, net	\$10,917	\$ 9,492

Note 5 – 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%).

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. As of December 31, 2003, \$679 million was available under these committed credit facilities, excluding the EEI facilities and the nuclear fuel lease. 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 received funds through direct loans from Ameren since it was 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 to be used for general corporate purposes including support of our commercial paper programs. The \$470 million in new facilities includes a \$235 million 364-day revolving credit facility and a \$235 million three-year revolving credit facility. These new credit facilities replaced Ameren's existing \$270 million 364-day revolving credit facility, which matured in July 2003, and a \$200 million facility, which would have matured in December 2003. In July 2003, Ameren also amended covenants in its \$130 million multi-year credit facility.

In April 2003, UE entered into a 364-day committed credit facility totaling \$75 million to be used for general corporate purposes including support of its commercial paper program. This facility makes borrowings available at various interest rates based on the London Interbank Offered Rate, agreed rates and other options. CIPS and CILCO can access this facility through the utility money pool.

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, the maximum amount that could be financed under the agreement was \$120 million. At December 31, 2003, \$67 million was financed under the lease. The nuclear lease agreement was terminated in February 2004.

We have money pool agreements with and among our subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained between rate-regulated and non rate-regulated businesses.

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 in 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.

Note 6 – Long-term Debt and Equity Financings

The following table presents long-term debt outstanding for Ameren and its subsidiaries as of December 31, 2003 and 2002:

	2003	2002
Ameren Corporation (parent only):		
2001 Floating Rate Notes due 2003	\$ –	\$ 150
2002 5.70% notes due 2007	100	100
Senior note, due 2007	345	345
Total long-term debt, gross	445	595
Less: Maturities due within one year	–	150
Long-term debt, net	\$ 445	\$ 445

UE:

First mortgage bonds: (a)		
7.65% Series due 2003	\$ –	\$ 100
6 7/8% Series due 2004	188	188
7 3/8% Series due 2004	85	85
6 3/4% Series due 2008	148	148
5.25% Senior secured notes due 2012	173	173
4.65% Senior secured notes due 2013	200	–
4.75% Senior secured notes due 2015	114	–
5.10% Senior secured notes due 2018	200	–
8 1/4% Series due 2022	–	104
8.00% Series due 2022	–	85
7.15% Series due 2023	–	75
7.00% Series due 2024	100	100
5.45% Series due 2028 (b)	44	44
5.50% Senior secured notes due 2034	184	–

	2003	2002
Environmental improvement and pollution control revenue bonds:		
1991 Series due 2020 (c)	\$ 43	\$ 43
1992 Series due 2022 (c)	47	47
1998 Series A due 2033 (c)	60	60
1998 Series B due 2033 (c)	50	50
1998 Series C due 2033 (c)	50	50
2000 Series A due 2035 (c)	64	64
2000 Series B due 2035 (c)	63	63
2000 Series C due 2035 (c)	60	60
Subordinated deferrable interest debentures:		
7.69% Series A due 2036 (d)	66	66
Capital lease obligations:		
Nuclear fuel lease	67	113
City of Bowling Green lease (Peno Creek CT)	100	103
Total long-term debt, gross	2,106	1,821
Less: Unamortized discount and premium	4	4
Less: Maturities due within one year	344	130
Long-term debt, net	\$ 1,758	\$ 1,687

CIPS:

First mortgage bonds: (a)		
6 3/8% Series Z due 2003	\$ –	\$ 40
6.99% Series 97-1 due 2003	–	5
6.49% Series 95-1 due 2005	20	20
7.05% Series 97-2 due 2006	20	20
7 1/2% Series X due 2007	–	50
5.375% Series due 2008	15	15
6.625% Series due 2011	150	150
7.61% Series 97-2 due 2017	40	40
6.125% Series due 2028	60	60

Pollution control revenue bonds:		
2000 Series A 5.5% due 2014 (e)	51	51
1993 Series C-1 5.95% due 2026 (e)	35	35
1993 Series C-2 5.70% due 2026	25	25
1993 Series A 6 3/8% due 2028	35	35
1993 Series B-1 5% due 2028 (e)	17	17
1993 Series B-2 5.90% due 2028	18	18
Total long-term debt, gross	486	581
Less: Unamortized discount and premium	1	2
Less: Maturities due within one year	–	45
Long-term debt, net	\$ 485	\$ 534

	2003	2002
Genco:		
Unsecured notes:		
2000 Senior notes Series C 7.75% due 2005	\$ 225	\$ 225
2000 Senior notes Series D 8.35% due 2010	200	200
2002 Senior notes Series F 7.95% due 2032	275	275
Total long-term debt, gross	700	700
Less: Unamortized discount and premium	2	2
Long-term debt, net	\$ 698	\$ 698
CILCO:		
First mortgage bonds: (a)		
7 1/2% Series due 2007	\$ 50	\$ —
Medium-term notes: (a)		
6.13% Series due 2005	16	—
7.73% Series due 2025	20	—
Pollution control refunding bonds: (a)(b)		
6.50% Series F due 2010	5	—
6.20% Series G due 2012	1	—
6.50% Series E due 2018	14	—
5.90% Series H due 2023	32	—
Bank term loans:		
Secured bank term loan due 2004	100	—
Total long-term debt, gross	238	—
Less: Maturities due within one year	100	—
Long-term debt, net	\$ 138	\$ —
CILCORP (parent only):		
8.70% Senior notes due 2009 (f)	\$ 229	\$ —
9.375% Senior notes due 2029 (f)	302	—
Long-term debt, net	531	—
CILCORP consolidated long-term debt, net	\$ 669	\$ —
EEl:		
2000 Bank term loan, 7.61% due 2004	\$ 40	\$ 40
1991 Senior medium term notes 8.60% due through 2005	13	20
1994 Senior medium term notes 6.61% due through 2005	16	23
Total long-term debt, gross	69	83
Less: Maturities due within one year	54	14
Long-term debt, net	\$ 15	\$ 69
Ameren consolidated long-term debt, net	\$4,070	\$3,433

(a) At December 31, 2003, a majority of property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued. CILCO's long-term debt is secured by a lien on substantially all of its property and franchises.

(b) Environmental Improvement or Pollution Control Series secured by first mortgage bonds.

(c) Interest rates, and the periods during which such rates apply, vary depending on our selection of certain defined rate modes. The average interest rates for the years 2003 and 2002 were as follows:

	2003	2002
1991 Series	1.60%	1.64%
1992 Series	1.64%	1.60%
1998 Series A	1.75%	1.53%
1998 Series B	1.75%	1.53%
1998 Series C	1.77%	1.53%
2000 Series A	1.80%	1.56%
2000 Series B	1.77%	1.52%
2000 Series C	1.75%	1.56%

(d) Under the terms of the subordinated debentures, UE may, under certain circumstances, defer the payment of interest for up to five years. Upon the election to defer interest payments, UE dividend payments to Ameren are prohibited.

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

(f) CILCORP's long-term debt is secured by a pledge of all of the common stock of CILCO. The amount of debt outstanding at CILCORP includes a purchase accounting fair market value adjustment of approximately \$96 million.

The following table presents the aggregate stated maturities of long-term debt for Ameren and its subsidiaries at December 31, 2003:

	Ameren (parent)	UE	CIPS	Genco
2004	\$ —	\$ 344	\$ —	\$ —
2005	—	3	20	225
2006	—	3	20	—
2007	445	4	—	—
2008	—	152	15	—
Thereafter	—	1,600	431	475
Total	\$445	\$2,106	\$486	\$ 700

	CILCORP (parent only)	CILCO	EEl	Total
2004	\$ —	\$100	\$54	\$ 498
2005	—	16	15	279
2006	—	—	—	23
2007	—	50	—	499
2008	—	—	—	167
Thereafter	531	72	—	3,109
Total	\$531	\$238	\$69	\$4,575

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

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 issuance 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 EEL 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 registration 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 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 and preferred stock 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.

In December 2003, Ameren repaid its 2001 Floating Rate Notes totaling \$150 million. These notes were repaid with available cash on hand.

In March 2002, Ameren issued \$345 million of adjustable conversion-rate equity security units and \$227 million of common stock (5 million shares at \$39.50 per share and 750,000 shares, pursuant to the exercise of an option granted to the underwriters, at \$38.865 per share). The \$25 adjustable conversion-rate equity security units each consisted of an Ameren senior unsecured note with a principal amount of \$25 and a contract to purchase, for \$25, a fraction of a share of Ameren common stock on May 15, 2005. The senior unsecured notes were recorded at their fair value of \$345 million and will mature on May 15, 2007. Total distributions on the equity security units will be at an annual rate of 9.75%, consisting of quarterly interest payments on the senior unsecured notes at the initial annual rate of 5.20% and adjustment payments under the stock purchase contracts at the annual rate of 4.55%. The stock purchase contracts require holders to purchase between 8.7 million and 7.4 million shares of Ameren common stock on

May 15, 2005, at the market price at that time, subject to a minimum share purchase price of \$39.50 and a maximum of \$46.61. The stock purchase contracts include a pledge of the related senior unsecured notes as collateral for the stock purchase obligation. The interest rate on the outstanding senior unsecured notes is subject to being reset by a remarketing agent for quarterly payments after May 15, 2005, until maturity. We recorded the net present value of the contracted stock purchase payments of \$46 million as an increase in Other Deferred Credits and Liabilities to reflect our obligation and a decrease in Other Paid-in Capital to reflect the fair value of the stock purchase contract. The liability for the contracted stock purchase adjustment payments (December 31, 2003 - \$21 million) will be reduced as such payments are made through May 15, 2005. We used the net proceeds from these offerings to repay short-term indebtedness and for general corporate purposes.

In September 2001, we began issuing new shares of common stock to satisfy dividend reinvestments and direct purchases under our DRPlus plan and in December 2001, we began issuing new shares of common stock in connection with our 401(k) plans. Previously, these requirements were met by purchasing outstanding shares. Under these plans, we issued 2.5 million, 2.3 million and 0.8 million shares of common stock in 2003, 2002 and 2001, respectively, that were valued at \$105 million, \$93 million and \$33 million for the respective years.

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. In 2002, UE issued \$173 million of 5.25% senior secured notes due September 1, 2012, under the shelf registration statement.

In March 2003, UE issued, pursuant to the August 2002 shelf registration statement, \$184 million of 5.50% senior secured notes due March 15, 2034, with interest payable semi-annually on March 15 and September 15 of each year beginning in September 2003. UE received net proceeds of \$180 million, which along with other funds were used in April 2003 to redeem \$104 million principal amount of outstanding 8 1/4% first mortgage bonds due October 15, 2022, at a redemption price of 103.61% of par, plus accrued interest, and to repay short-term debt incurred to pay at maturity \$75 million principal amount of 8.33% first mortgage bonds that matured in December 2002.

In April 2003, UE issued, pursuant to the August 2002 shelf registration statement, \$114 million of 4.75% senior secured notes due April 1, 2015, with interest payable semi-annually on April 1 and October 1 of each year beginning in October 2003. UE received net proceeds of \$113 million, which along with other funds were used in May 2003, to redeem \$85 million principal amount of outstanding 8.00% first mortgage bonds due December 15, 2022, at a redemption price of 103.38% of par, plus accrued interest, and to reduce short-term debt.

In July 2003, UE issued, pursuant to the August 2002 shelf registration statement, \$200 million of 5.10% senior secured notes due August 1, 2018, with interest payable semi-annually on August 1 and February 1 of each year beginning in February 2004. UE received net proceeds of \$198 million, which along with other funds were used to repay short-term debt incurred to fund the maturity of \$100 million principal amount 7.65% first mortgage bonds due July 15, 2003, and to repay \$21 million of short-term debt. The remaining proceeds were used in August 2003, to redeem \$75 million principal amount of outstanding 7.15% first mortgage bonds due August 1, 2023, at a redemption price of 103.01% of par, plus accrued interest. The amount of securities remaining available for issuance pursuant to the 2002 shelf registration statement was \$79 million as of August 2003.

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 is included in the \$1 billion of securities available to be issued under this shelf registration statement. In October 2003, UE issued, pursuant to the September 2003 shelf registration statement, \$200 million of 4.65% senior notes due October 1, 2013, with interest payable semi-annually on April 1 and October 1 of each year beginning in April 2004. UE received net proceeds of \$198 million, which were used to repay outstanding short-term debt. The amount of securities remaining available for issuance totaled \$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.

In December 2002, upon receipt of all necessary federal and state regulatory approvals, UE, pursuant to Missouri economic development statutes, conveyed most of its Penno Creek CT facility to the City of Bowling Green, Missouri in exchange for the issuance by the City of a taxable industrial development revenue bond in the amount of \$103 million. Concurrently, the City leased back the

facility to UE for a term of 20 years. The lease term is the same as the final maturity of the bond purchased by UE. While the lease is a capital lease, no capital was raised in the transaction. UE is responsible for making rental payments under the lease in an amount sufficient to pay the debt service of the bond. The City's ownership of the facility during the term of the bond and the lease is expected to result in property tax savings to UE. Under the terms of the lease, UE retains all operation and maintenance responsibilities for the facility and ownership of the facility is returned to UE at the expiration of the lease.

Nuclear Fuel Lease

UE had a lease agreement, which was scheduled to expire on August 31, 2031, that provided for the financing of a portion of its nuclear fuel that was processed for use or was consumed at UE's Callaway Nuclear Plant. The lease agreement had variable interest rates based on short-term commercial paper interest rates. In February 2004, UE terminated this lease.

UE capitalized the cost of the leased nuclear fuel incurred by the lessor, plus certain interest costs, and recorded the related lease obligation. Total interest charges under the lease were \$2 million in 2003, \$2 million in 2002 and \$4 million in 2001. Interest charges for these years were based on average interest rates of approximately 2% for 2003, 2% for 2002 and 5% for 2001. Interest charges of \$1 million in 2003, \$2 million in 2002 and \$4 million in 2001 were capitalized.

CIPS

In March 2003, CIPS repaid its \$5 million principal amount 6.99% Series 97-1 first mortgage bonds on their maturity date. In April 2003, CIPS repaid its \$40 million principal amount 6 3/8% Series Z first mortgage bonds on their maturity date and also redeemed prior to maturity and at par, its \$50 million 7 1/2% Series X first mortgage bonds due July 1, 2007. In December 2003, CIPS redeemed its \$30 million auction preferred stock at par. All redemptions and repayments were made with available cash and borrowings from the utility money pool.

In May 2001, a shelf registration statement filed by CIPS with the SEC was declared effective. This registration statement enables CIPS to offer from time to time senior notes in one or more series with an offering price not to exceed \$250 million. In June 2001, CIPS issued, under the shelf registration statement, \$150 million of senior notes due in June 2011, with an interest rate of 6.625%. Until the release date as described in the senior secured note indenture, the senior notes will be secured by a related series of CIPS' first mortgage bonds. The proceeds of these senior notes were used to repay short-term debt and first mortgage bonds maturing in June 2001. At December 31, 2003, the amount of securities remaining available for issuance pursuant to the shelf registration statement was \$100 million.

GENCO

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

CILCORP

In conjunction with Ameren's acquisition of CILCORP, CILCORP's long-term debt was recorded at fair value. This resulted in recognition of fair value related adjustment increases of \$71 million related to CILCORP's 9.375% senior bonds due 2029 and \$40 million related to its 8.70% senior notes due 2009. Amortization related to these fair value adjustments was approximately \$7 million for the year ended December 31, 2003, and was included in interest expense in the Consolidated Statement of Income for Ameren.

In September 2003, CILCORP repurchased, prior to maturity, \$13 million in principal amount of its 9.375% senior bonds and \$27 million in principal amount of its 8.70% senior notes. Premiums paid to repurchase these bonds resulted in an aggregate reduction of the fair value adjustments recorded upon acquisition of \$8 million. CILCORP repurchased these senior bonds and notes through a direct loan from Ameren.

CILCO

In February 2003, CILCO repaid \$25 million in principal amount of its 6.82% Series medium-term notes on their maturity date. In April 2003, three series of CILCO's first mortgage bonds were redeemed prior to maturity. These redemptions included CILCO's \$65 million principal amount 8 1/5% Series due January 15, 2022, at a redemption price of 103.29%, and two 7.80% Series totaling \$10 million in principal amount due February 9, 2023, at a redemption price of 103.90%. In August 2003, CILCO repaid two bank loans totaling \$5 million prior to their scheduled maturity dates. In July 2003, a series of CILCO preferred stock was reduced by \$1 million as a result of a mandatory sinking fund provision. CILCO expects to repay its \$100 million term loan facility in the first quarter of 2004. Redemptions and repayments were made with available cash, direct borrowings from Ameren and borrowings from the utility money pool.

MEDINA VALLEY

In June 2003, Medina Valley repaid, prior to maturity, with funds borrowed from the non state-regulated subsidiary money pool, a

\$36 million secured term loan with an effective interest rate of 7.65% and terminated two related interest rate swaps at a total redemption cost of \$44 million. This repayment eliminated the outstanding bank debt at Medina Valley.

AMORTIZATION OF DEBT ISSUANCE COSTS AND ASSOCIATED PREMIUMS AND DISCOUNTS

Amortization of debt issuance costs and any premium or discounts included in interest expense in the Consolidated Statement of Income was \$10 million, \$8 million and \$5 million for the years ended December 31, 2003, 2002, and 2001, respectively.

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 subsequently, 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 subsequently, 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 had restrictions on the payment of dividends and its ability to otherwise make distributions with

respect to its common stock as a result of its \$100 million bank term loan. However, this loan is expected to be repaid in the first quarter of 2004.

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. We do not expect to engage in any significant off-balance sheet financing arrangements in the near future.

Note 7 – Restructuring Charges and Other Special Items

Ameren recorded a coal contract settlement gain of \$51 million in 2003. This gain represented a return of coal costs plus accrued interest accumulated by a coal supplier for reclamation of a coal mine that supplied a UE power plant. We entered into a settlement agreement with the coal supplier to return the accumulated reclamation funds, which will be paid ratably through December 2004. Our accounts receivable balance related to this settlement at December 31, 2003 was \$36 million.

Ameren recorded voluntary employee retirement and other restructuring charges of \$92 million in 2002. These charges included a voluntary retirement program charge of \$75 million based on voluntary retirements of approximately 550 employees. These charges primarily related to special termination benefits associated with our pension and postretirement benefit plans. Most of the employees who voluntarily retired accepted retirement in 2002 and left Ameren in early 2003.

In addition, in 2002, Ameren recorded a charge of approximately \$17 million primarily associated with the retirement of 343 megawatts of rate-regulated generating capacity at UE's Venice, Illinois plant and temporary suspension of operations of two coal-fired generating units (126 megawatts) at Genco's Meredosia, Illinois plant.

Note 8 – Other Income and Deductions

The following table presents Other Income and Deductions for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Miscellaneous income:			
Interest and dividend income	\$ 10	\$ 8	\$ 4
Gain on disposition of property	–	3	5
Contribution in aid of construction	1	1	7
Allowance for equity funds used during construction	4	6	13
Other	12	3	6
Total miscellaneous income	\$ 27	\$ 21	\$ 35

	2003	2002	2001
Miscellaneous expense:			
Minority interest in subsidiary	\$ (7)	\$(14)	\$ (4)
Loss on disposition of property	(1)	–	(2)
Donations, including 2002 UE electric rate settlement	(5)	(26)	(1)
Other	(9)	(10)	(9)
Total miscellaneous expense	\$(22)	\$(50)	\$(16)

Note 9 – Derivative Financial Instruments

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

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

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

In addition, we may purchase additional power, again within risk management guidelines, in anticipation of power requirements and future price changes. Certain derivative contracts we enter into on a regular basis as part of our power risk management program do not qualify for hedge accounting or the normal purchase and sale exceptions under SFAS No. 133. Accordingly, these contracts are recorded at fair value with changes in the fair value charged or credited to the income statement in the period in which the change occurred. Contracts we enter into as part of our power risk management program may be settled by either physical delivery or net settled with the counterparty.

CASH FLOW HEDGES

We routinely enter into forward purchase and sales contracts for electricity based on forecasted levels of economic generation and customer requirements. The relative balance between customer requirements and economic generation varies throughout the year. The contracts typically cover a period of twelve months or less. The

purpose of these contracts is to hedge against possible price fluctuations in the spot market for the period covered under the contracts. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objective and strategy for undertaking various hedge transactions. The mark-to-market value of cash flow hedges will continue to fluctuate with changes in market prices up to contract expiration.

The following table presents balances in certain accounts for cash flow hedges as of December 31, 2003 and 2002:

	2003	2002
Balance Sheet:		
Other assets	\$16	\$8
Other deferred credits and liabilities	4	1
Accumulated OCI:		
Power forwards ^(a)	3	1
Interest rate swaps ^(b)	5	5
Gas swaps and futures contracts ^(c)	6	2
Call options ^(d)	2	6

(a) Represents the mark-to-market value for the hedged portion of electricity price exposure for periods generally less than one year. Certain contracts designated as hedges of electricity price exposure have terms up to five years.

(b) Represents a gain associated with interest rate swaps at Genco that were a partial hedge of the interest rate on debt issued in June 2002. The swaps cover the first ten years of debt that has a 30-year maturity and the gain in OCI is amortized over a ten-year period that began in June 2002.

(c) Represents a gain associated with natural gas swaps and futures contracts. The swaps are a partial hedge of our natural gas requirements through October 2006. CILCORP and CILCO amounts represent a gain associated with a partial hedge of natural gas requirements through March 2007.

(d) Represents the mark-to-market gain of two call options accounted for as cash flow hedges for coal held with two suppliers. One of these options to purchase coal expired in October 2003 and the other option expires in July 2005. The final value of the options will be recognized as a reduction in fuel costs as the hedged coal is burned.

The pretax net gain or loss on power forward derivative instruments included in Other Income and Deductions, which represented the impact of discontinued cash flow hedges, the ineffective portion of cash flow hedges, as well as the reversal of amounts previously recorded in OCI due to transactions going to delivery or settlement, totaled less than a \$1 million loss for the year ended December 31, 2003 (2002 – \$3 million loss).

OTHER DERIVATIVES

The following table represents the net change in market value of option transactions, which are used to manage our positions in SO₂ allowances, coal, heating oil and electricity or power. Certain of these transactions are treated as non-hedge transactions under SFAS No. 133. The net change in the market value of SO₂ options is recorded in Operating Revenues - Electric, while the net change in the market value of coal, heating oil and electricity or power options is recorded as Operating Expenses – Fuel and Purchased Power in the Consolidated Statement of Income.

Gains (Losses) (a)	2003	2002	2001
SO ₂ options	\$1	\$2	\$(1)
Coal options	1	1	—
Power options	—	2	—

(a) Heating oil option gains and losses were less than \$1 million for all periods shown above.

Note 10 – Stockholder Rights Plan and Preferred Stock

STOCKHOLDER RIGHTS PLAN

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

PREFERRED STOCK

All classes of UE's, CIPS' and CILCO's preferred stock are entitled to cumulative dividends and have voting rights. Ameren has 100 million shares of \$0.01 par value preferred stock authorized, with no shares outstanding. CIPS has 2.6 million shares of no par value preferred stock authorized, with no shares outstanding. UE has 7.5 million shares authorized of \$1 par value preference stock and CILCO has 2.0 million shares authorized of no par value preference stock. No shares of preference stock have been issued.

The following table presents the outstanding preferred stock of our subsidiaries that is not subject to mandatory redemption and is entitled to cumulative dividends and is redeemable, at the option of the issuer, at the prices presented as of December 31, 2003 and 2002:

		Redemption Price (per share)	2003	2002
UE:				
Without par value and stated value of \$100 per share, 25 million shares authorized				
\$7.64 Series	330,000 shares	\$103.82 ^(a)	\$ 33	\$ 33
\$5.50 Series A	14,000 shares	110.00	1	1
\$4.75 Series	20,000 shares	102.176	2	2
\$4.56 Series	200,000 shares	102.47	20	20
\$4.50 Series	213,595 shares	110.00 ^(b)	21	21
\$4.30 Series	40,000 shares	105.00	4	4
\$4.00 Series	150,000 shares	105.625	15	15
\$3.70 Series	40,000 shares	104.75	4	4
\$3.50 Series	130,000 shares	110.00	13	13

CIPS:

With par value of \$100 per share,

2 million shares authorized

4.00% Series	150,000 shares	\$101.00	\$ 15	\$ 15
4.25% Series	50,000 shares	102.00	5	5
4.90% Series	75,000 shares	102.00	8	8
4.92% Series	50,000 shares	103.50	5	5
5.16% Series	50,000 shares	102.00	5	5
1993 Auction	300,000 shares	100.00	—	30
6.625% Series	125,000 shares	100.00	12	12

CILCO: ^(c)

With par value of \$100 per share,

1.5 million shares authorized

4.50% Series	111,264 shares	\$110.00	\$ 11	\$ —
4.64% Series	79,940 shares	102.00	8	—

Total **\$182** **\$193**

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

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

(c) Acquired on January 31, 2003.

The following table presents the outstanding preferred stock of our subsidiary that is subject to mandatory redemption, is entitled to cumulative dividends and is redeemable, at a determinable price on a fixed date or dates, at the prices presented as of December 31, 2003 and 2002, respectively:

		Redemption Price (per share)	2003	2002
CILCO: (a)				
Without par value and stated value of \$100 per share, 3.5 million shares authorized				
5.85% Series	220,000 shares	\$100.00 ^(b)	\$ 21	\$ —

(a) Beginning July 1, 2003, this preferred stock became redeemable, at the option of CILCO, at \$100 per share. A mandatory redemption fund was established on July 1, 2003. The fund provides for the redemption of 11,000 shares for \$1.1 million on July 1 of each year through July 1, 2007. On July 1, 2008, the remaining shares outstanding will be retired for \$16.5 million.

(b) In the event of voluntary or involuntary liquidation, the stockholder receives \$100 per share plus accrued dividends.

Note 11 – Retirement Benefits

We have defined benefit and postretirement benefit plans covering substantially all employees of UE, CIPS, CILCORP, CILCO and Ameren Services and certain employees of Resources Company and its subsidiaries, including Genco. Ameren uses a measurement date of December 31 for its pension and postretirement benefit plans.

INVESTMENT STRATEGY AND RETURN ON ASSET ASSUMPTION

The primary objective of the Ameren Retirement Plan and postretirement benefit plans is to provide eligible employees with pension and postretirement healthcare benefits. Ameren manages plan assets in accordance with the “prudent investor” guidelines contained in the ERISA. Ameren’s goal is to earn the highest possible return on plan assets consistent with its tolerance for risk. Ameren delegates investment management to specialists in each asset class and where appropriate, provides the investment manager with specific guidelines which include allowable and/or prohibited investment types. Ameren regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns and volatility of the various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolio was developed and adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

PENSION

Pension benefits are based on the employees’ years of service and compensation. Our plans are funded in compliance with income tax regulations and federal funding requirements. We made cash contributions to our defined benefit retirement plan qualified trusts of \$25 million and \$31 million during 2003 and 2002, respectively. 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. The following table presents the funded status of our pension plans for the years ended December 31, 2003 and 2002:

	2003	2002
Change in benefit obligation:		
Net benefit obligation at beginning of year	\$1,587	\$1,418
Service cost	37	33
Interest cost	128	103
Plan amendments	20	–
Actuarial loss	123	64
Addition from CILCO	355	–
Special termination benefits ^(a)	2	65
Benefits paid	(163)	(96)
Net benefit obligation at end of year	2,089	1,587
Change in plan assets:		
Fair value of plan assets		
at beginning of year	1,059	1,225
Actual return on plan assets	283	(101)
Addition from CILCO	236	–
Employer contributions	25	31
Benefits paid ^(b)	(160)	(96)
Fair value of plan assets at end of year	1,443	1,059
Funded status – deficiency	646	528
Unrecognized net actuarial loss	(267)	(324)
Unrecognized prior service cost	(80)	(68)
Unrecognized net transition asset	2	3
Accrued pension cost at December 31, 2003	\$ 301	\$ 139

(a) Special termination benefits for 2002 represent the enhanced improvement in benefits provided to the approximate 550 employees who voluntarily retired in 2002. See also Note 7 – Restructuring Charges and Other Special Items for further information.

(b) Excludes amounts paid from company funds.

The following table presents the assumptions used to determine benefit obligations at December 31, 2003 and 2002:

	2003	2002
Discount rate at measurement date	6.25%	6.75%
Increase in future compensation	3.25	3.75

Based on our assumptions at December 31, 2003, and in order to maintain minimum funding levels for our pension plan, we expect to be required under ERISA to fund an average of approximately \$115 million annually from 2005 through 2008 assuming the passage of a law which would be retroactive to January 1, 2004, to extend the temporary interest rate relief. We expect UE’s, CIPS’, Genco’s and CILCO’s portion of the 2005 to 2008 funding requirements to be approximately 65%, 10%, 10% and 15%, respectively. 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.

The following table presents the amounts recorded in the Consolidated Balance Sheet as of December 31, 2003 and 2002:

	2003	2002
Accrued pension liability	\$ 476	\$ 377
Intangible asset	(84)	(74)
Accumulated OCI	(91)	(164)
Accrued pension cost at December 31, 2003	\$ 301	\$ 139

The following table presents our pension plan asset categories as of December 31, 2003 and 2002 and our target allocations for 2004:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31,	
		2003	2002
Equity securities	40 - 80%	63%	59%
Debt securities	18 - 55	31	37
Real estate	0 - 6	4	3
Other	0 - 4	2	1
Total		100%	100%

The following table presents the projected benefit obligation, the accumulated benefit obligation and the fair value of plan assets for plans that have a projected benefit obligation and an accumulated benefit obligation in excess of plan assets at December 31, 2003 and 2002:

	2003	2002
Projected benefit obligation	\$2,089	\$ 1,587
Accumulated benefit obligation	1,919	1,436
Fair value of plan assets	1,443	1,059

The following table presents the components of the net periodic pension benefit cost during 2003, 2002, and 2001:

	2003	2002	2001
Service cost	\$ 37	\$ 33	\$ 32
Interest cost	128	103	100
Expected return on plan assets	(124)	(114)	(115)
Amortization of:			
Transition asset	(1)	(1)	(1)
Prior service cost	9	9	9
Actuarial loss (gain)	7	(12)	(21)
Net periodic benefit cost	56	18	4
Net periodic benefit cost, including special termination benefits	\$ 58	\$ 83	\$ 4

Prior service cost is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan. The net actuarial (gain) loss subject to amortization is amortized on a straight-line basis over ten years.

The expected pension benefit payments from qualified trust and company funds, which reflect expected future service, are as follows:

	Pension from Qualified Trust	Pension from Company Funds
2004	\$125	\$2
2005	122	2
2006	127	2
2007	130	2
2008	134	2
2009 - 2013	745	8

The following table presents the assumptions used to determine net periodic benefit cost for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Discount rate at measurement date	6.75%	7.25%	7.50%
Expected return on plan assets	8.50	8.50	8.50
Increase in future compensation	3.75	4.25	4.50

POSTRETIREMENT

Our funding policy for postretirement benefits is primarily to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense.

We made cash contributions to our postretirement plan of \$70 million during 2003 and \$74 million in 2002. We expect to make contributions of approximately \$80 million during 2004.

The following table presents the funded status of Ameren's postretirement benefit plans at December 31, 2003 and 2002:

	2003	2002
Change in benefit obligation:		
Net benefit obligation at beginning of year	\$771	\$ 701
Service cost	13	26
Interest cost	62	51
Employee contributions	3	2
Plan amendments ^(a)	—	(186)
Actuarial loss	62	211
Addition from CILCO	156	—
Special termination benefits ^(b)	—	8
Benefits paid	(54)	(42)
Net benefit obligation at end of year	\$1,013	\$ 771

	2003	2002
Change in plan assets :		
Fair value of plan assets		
at beginning of year	\$ 309	\$ 300
Actual return on plan assets	62	(26)
Addition from CILCO	33	–
Employer contributions	70	74
Employee contributions	3	2
Benefits paid (c)	(54)	(41)
Fair value of plan assets at end of year	423	309
Funded status – deficiency	590	462
Unrecognized net actuarial loss	(392)	(389)
Unrecognized prior service cost	43	47
Unrecognized net transition obligation (d)	(19)	(21)
Postretirement benefit liability		
at December 31, 2003	\$ 222	\$ 99

(a) Plan amendments represent a favorable change to our net benefit obligation and relate to increasing retiree premiums and placing limits on healthcare benefits.

(b) Special termination benefits for 2002 represent the enhanced improvement in benefits provided to the approximate 550 employees who voluntarily retired in 2002. See also Note 7 – Restructuring Charges and Other Special Items for further information.

(c) Excludes amounts paid from company funds.

(d) Ameren's transition obligation at December 31, 2003, is being amortized over the next 11 years.

The following table presents the assumptions used to determine the benefit obligations at December 31, 2003 and 2002:

	2003	2002
Discount rate at measurement date	6.25%	6.75%
Medical cost trend rate (initial)	9.00	10.00
Medical cost trend rate (ultimate)	5.00	5.00

The following table presents the accumulated postretirement benefit obligation and the fair value of plan assets which have an accumulated postretirement benefit obligation in excess of plan assets at December 31, 2003 and 2002:

	2003	2002
Accumulated postretirement benefit obligation	\$1,013	\$771
Fair value of plan assets	423	309

The following table presents the components of Ameren's net periodic postretirement benefit cost as of December 31, 2003, 2002, and 2001:

	2003	2002	2001
Service cost	\$ 13	\$ 26	\$ 23
Interest cost	62	51	47
Expected return on plan assets	(33)	(27)	(25)
Amortization of:			
Transition obligation	2	16	16
Prior service cost	(3)	–	–
Actuarial loss	34	8	2
Net periodic benefit cost	75	74	63
Net periodic benefit cost, including special termination benefits	\$ 75	\$ 82	\$ 63

Prior service cost is amortized on a straight-line basis over the average future service of active plan participants benefiting under the postretirement plans. The net actuarial loss subject to amortization is amortized on a straight-line basis over ten years.

UE, CIPS, Genco, CILCORP and CILCO are responsible for their proportional share of the postretirement benefit costs. Postretirement benefit costs were \$75 million for 2003, \$74 million for 2002 and \$63 million for 2001.

The following expected postretirement benefit payments, which reflect expected future service, are as follows:

	Benefits from Qualified Trust	Benefits from Company Funds
2004	\$ 63	\$1
2005	67	1
2006	69	1
2007	72	1
2008	73	1
2009 - 2013	399	6

The following table presents our postretirement plan asset categories as of December 31, 2003 and 2002 and our target allocations for 2004:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31,	
		2003	2002
Equity securities	40 - 80%	57%	49%
Debt securities	20 - 60	32	38
Other	0 - 15	11	13
Total		100%	100%

The following table presents the assumptions used to determine net periodic benefit cost for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Discount rate at measurement date	6.75%	7.25%	7.50%
Expected return on plan assets	8.50	8.50	8.50
Medical cost trend rate (initial)	10.00	5.25	5.00
Medical cost trend rate (ultimate)	5.00	5.25	5.00

Assumed healthcare cost trend rates have a significant effect on the amounts reported for healthcare plans. In addition, we have plan limits on the amount the company will contribute to future postretirement benefits. The following table presents the effects of a one percent change in assumed healthcare cost trend rates:

	1% Increase	1% Decrease
Effect on net periodic cost	\$ 3	\$ (3)
Effect on accumulated postretirement benefit obligation	37	(36)

OTHER

Ameren, CIPS and CILCO sponsor 401(k) plans for eligible employees. The plans allow employees to contribute a portion of their base pay in accordance with specific guidelines. Ameren, CIPS and CILCO match a percentage of the employee contributions up to certain limits. Ameren's and CILCO's matching contributions to the 401(k) plans totaled \$14 million and \$1 million, respectively, in 2003, and \$14 million and \$13 million for Ameren in 2002 and 2001, respectively. CIPS' matching contributions to the 401(k) plan were less than \$1 million in 2003, 2002 and 2001.

Note 12 – Stock-based Compensation

Ameren has a long-term incentive plan for eligible employees called the Long-term Incentive Plan of 1998, which provides for the grant of options, performance awards, restricted stock, dividend equivalents and stock appreciation rights. Restricted stock awards were granted in 2003, 2002 and 2001 as a component of our compensation programs. We applied APB Opinion No. 25 in accounting for our stock-based compensation for years prior to 2003. There have not been any stock options granted since December 31, 2000. Effective January 1, 2003, we adopted SFAS No. 123. See Note 1 – Summary of Significant Accounting Policies for further information.

RESTRICTED STOCK

Restricted stock awards may be granted under our long-term incentive plan. Upon the achievement of certain performance levels, the restricted stock award vests over a period of seven years, beginning at the date of grant, and includes provisions

requiring certain stock ownership levels based on position and salary. An accelerated vesting provision is also included in this plan which reduces the vesting period from seven years to three years. During 2003, 2002 and 2001, respectively, 152,956, 154,678 and 141,788 restricted stock awards were granted. The weighted-average fair value for restricted stock awards granted in 2003, 2002 and 2001 was \$39.74, \$42.50 and \$39.60 per share, respectively. We record unearned compensation (as a component of stockholders' equity) equal to the market value of the restricted stock on the date of grant and charge the unearned compensation to expense over the vesting period. In accordance with SFAS No. 123, we recorded compensation expense relating to restricted stock awards of approximately \$5 million in 2003 (which included accelerated expense of approximately \$1 million related to employee retirements), \$2 million in 2002 (which included accelerated expense of approximately \$1 million related to our voluntary retirement program offered in 2002) and approximately \$1 million in 2001.

STOCK OPTIONS

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

The following table presents Ameren stock option activity during 2003, 2002 and 2001:

	2003	
	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,977,453	\$ 35.10
Granted	–	–
Exercised	477,777	35.78
Cancelled or expired	–	–
Outstanding at end of year	1,499,676	34.88
Exercisable at end of year	1,032,001	\$ 36.00

	2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	2,241,107	\$ 35.23	2,430,532	\$ 35.38
Granted	—	—	—	—
Exercised	260,324	36.11	106,416	38.31
Cancelled or expired	3,330	43.00	83,009	35.77
Outstanding at end of year	1,977,453	35.10	2,241,107	35.23
Exercisable at end of year	901,187	\$ 36.97	572,092	\$ 38.74

The following table presents additional information about stock options outstanding at December 31, 2003:

Exercise Price	Outstanding Shares	Weighted Average Life (Years)	Exercisable Shares
\$31.00	676,650	5.1	326,700
35.50	800	1.6	800
35.875	25,030	1.3	25,030
36.625	407,000	4.4	289,275
38.50	59,042	3.0	59,042
39.25	265,464	3.7	265,464
39.8125	5,300	4.5	5,300
43.00	60,390	2.0	60,390

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

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

Note 13 – Income Taxes

Total income tax expense for 2003 resulted in an effective tax rate of 37% on income before income taxes (2002 – 38%, 2001 – 39%).

The following table presents the principal reasons why the effective income tax rate differed from the statutory federal income tax rate for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Statutory federal income tax rate:	35%	35%	35%
Increases (decreases) from:			
Depreciation differences	1	2	2
State tax	3	3	3
Other	(2)	(2)	(1)
Effective income tax rate	37%	38%	39%

The following table presents the components of income tax expense for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Taxes currently payable (principally federal):			
Included in operating expenses	\$327	\$185	\$276
Included in other income	(14)	(13)	5
	313	172	281
Deferred taxes (principally federal):			
Included in operating expenses:			
Depreciation differences	27	83	9
Other	(15)	(9)	19
Included in other income	(1)	—	—
	11	74	28
Deferred investment tax credits, amortization:			
Included in operating expenses	(11)	(9)	(8)
Total income tax expense	\$313	\$237	\$301

In accordance with SFAS No. 109, "Accounting for Income Taxes," a regulatory asset, representing the probable recovery from customers of future income taxes, which is expected to occur when temporary differences reverse, was recorded along with a corresponding deferred tax liability. Also, a regulatory liability, recognizing the lower expected revenue resulting from reduced income taxes associated with amortizing accumulated deferred investment tax credits was recorded. Investment tax credits have been deferred and will continue to be credited to income over the lives of the related property.

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

The following table presents the deferred tax assets and deferred tax liabilities recorded as a result of temporary differences at December 31, 2003 and 2002:

	2003	2002
Accumulated deferred income taxes, net:		
Depreciation	\$1,437	\$ 1,161
Regulatory assets (liabilities), net	312	405
Capitalized taxes and expenses	388	237
Deferred benefit costs	(223)	(79)
Other	(59)	(12)
Total net accumulated deferred income tax liabilities	\$1,855	\$ 1,712

Note 14 – Commitments and Contingencies

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

CAPITAL EXPENDITURES

See Note 3 – Rate and Regulatory Matters for information regarding Ameren's 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. Additionally, Ameren's future estimated capital expenditures include the addition of new CTs with approximately 330 megawatts of capacity at its Venice, Illinois location 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.

FUEL PURCHASE COMMITMENTS

To supply a portion of the fuel requirements of our generating plants, we have entered into various long-term commitments for the procurement of coal, natural gas and nuclear fuel. In addition, we have entered into various long-term commitments for the purchase of electricity. The following table presents the total estimated fuel purchase commitments at December 31, 2003:

	Coal	Gas	Nuclear	Electric Capacity
2004	\$ 703	\$267	\$38	\$ 25
2005	516	178	11	23
2006	419	93	9	23
2007	266	21	1	23
2008	273	5	10	23
Thereafter (a)	202	5	10	2
Total	\$2,379	\$569	\$79	\$119

(a) Commitments for coal, natural gas, nuclear fuel and the purchase of electricity are until 2010, 2012, 2009 and 2010, respectively.

NUCLEAR PLANT INSURANCE COVERAGE

The following table presents insurance coverage at Ameren's Callaway Nuclear Plant at December 31, 2003:

Type and Source of Coverage	Maximum Coverages	Maximum Assessments for Single Incidents
Public liability:		
American Nuclear Insurers	\$ 300	\$ –
Pool participation	10,562	101 (a)
	\$10,862 (b)	\$101
Nuclear worker liability:		
American Nuclear Insurers	\$ 300 (c)	\$ 4
Property damage:		
Nuclear Electric Insurance Ltd.	\$ 2,750 (d)	\$ 21
Replacement power:		
Nuclear Electric Insurance Ltd.	\$ 490 (e)	\$ 7

(a) Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended (Price-Anderson). This is subject to retrospective assessment with respect to loss from an incident at any U.S. reactor, payable at \$10 million per year. Price-Anderson expired in August 2002 and the temporary extension expired December 31, 2003. Renewal legislation is pending before Congress. Until Price-Anderson is renewed, its provisions continue to apply to existing nuclear plants.

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

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

(d) Includes premature decommissioning costs.

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

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

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

LEASES

The following table presents our lease obligations at December 31, 2003:

	Total	Less than 1 Year	1-3 Years	3-5 Years	After 5 Years
Capital leases (a)	\$167	\$ 70	\$ 7	\$ 8	\$ 82
Operating leases (b)	146	20	25	21	80
Total lease obligations	\$313	\$ 90	\$ 32	\$ 29	\$162

(a) See Note 6 – Long-term Debt and Equity Financings for further discussion.

(b) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The amounts for these items are included in the less than 1 year, 1-3 years and 3-5 years columns. Amounts for after 5 years are not included in the total amount due to the indefinite periods. The estimated obligation for after 5 years is \$2 million annually for both the real estate leases and the railroad licenses.

We lease various facilities, office equipment, plant equipment and railcars under operating leases. We also have a capital lease relating to UE's Peno Creek CT facility. We had a capital lease relating to nuclear fuel for our Callaway Nuclear Plant which was terminated early in February 2004. See Note 6 – Long-term Debt and Equity Financings for further information. As of December 31, 2003, rental expense, included in Other Operations and Maintenance expenses, totaled approximately \$61 million (2002 - \$21 million; 2001 - \$22 million).

ENVIRONMENTAL MATTERS

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

Clean Air Act

Both federal and state laws require significant reductions in SO₂ and NO_x emissions that result from burning fossil fuels. The Clean Air Act creates a marketable commodity called an SO₂ "allowance." Each allowance gives the owner the right to emit one ton of SO₂. 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 SO₂ allowance banks. Our generating facilities comply with the SO₂ 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 rules 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 approximately \$210 million to \$250 million. 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.

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.

In mid-December 2003, the EPA issued proposed regulations with respect to SO₂ 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 as final late in 2004 or early 2005. We preliminarily estimate capital costs based on current technology on the Ameren systems to comply with the SO₂ and NO_x rules, as proposed, to range from \$400 million to \$600 million by 2010, with an additional \$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 anticipates additional capital costs to comply with the mercury rules could 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 Mercury and Interstate Air Quality Rules described above.

Global Climate

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

Clean Water Act

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. These rules pertain to existing generating facilities that currently employ a cooling water intake structure whose flow exceeds 50 million gallons per day. The proposed rule may require us to install additional intake screens or other protective measures, as well as extensive site specific study and monitoring requirements. There is also the possibility that the proposed rules may lead to the installation of cooling towers on some of our facilities. Final rules are expected by March 2004. Our compliance costs associated with the final rules are unknown, but are not expected to have a material impact on our future financial position, results of operations or liquidity.

Remediation

We are involved in a number of remediation actions to clean up hazardous waste sites as required by federal and state law. Such statutes require that responsible parties fund remediation actions regardless of fault, legality of original disposal, or ownership of a disposal site. Ameren has been identified by the federal or state governments as a potentially responsible party at several contaminated sites. Several of these sites involve facilities which were transferred by CIPS to Genco in May 2000 and were transferred by CILCO to AERG in October 2003. As part of each transfer, the transferor (CIPS or CILCO) has contractually agreed to indemnify the transferee (Genco or AERG) for remediation costs associated with pre-existing environmental contamination at the transferred sites.

Ameren owns or is otherwise responsible for 18 former MGP sites in Illinois. These sites are in various stages of investigation, evaluation and remediation. Under its current schedule, Ameren

anticipates that remediation at these sites should be completed by 2010. The ICC permits the recovery of remediation and litigation costs associated with former MGP sites located in Illinois from Ameren's Illinois electric and natural gas utility customers through environmental riders. To be recoverable, such costs must be prudently and properly incurred and are subject to annual reconciliation review by the ICC. The total costs deferred, net of recoveries from insurers and through environmental adjustment rate riders, through or at December 31, 2003, were \$31 million.

In addition, Ameren owns or is otherwise responsible for 10 MGP sites in Missouri and one in Iowa. Unlike in Illinois, Ameren does not have in effect in Missouri a rate rider mechanism which permits remediation costs associated with MGP sites to be recovered from utility customers, and Ameren does not have any retail utility operations in Iowa. Because of the unknown and unique characteristics of each site (such as amount and type of residues present, physical characteristics of the site and the environmental risk), and uncertain regulatory requirements, we are not able to determine the maximum liability for the remediation of these sites. Ameren has recorded a \$12 million liability as of December 31, 2003, representing its estimated minimum obligation. At this time, we are unable to determine what portion of these costs, if any, will be eligible for recovery from insurance carriers.

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

In September 2000, the Department of Justice was granted leave by the United States District Court - Southern District of Illinois to add numerous additional parties, including Ameren, to a pre-existing lawsuit between the government and others. The government seeks recovery of response costs under CERCLA (Superfund), incurred in connection with the remediation of Sauget Area 1. In October 2003, the government dismissed Ameren as a party to the lawsuit and Ameren considers the Sauget Area 1 litigation closed.

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

In October 2002, CILCO was included in a Unilateral Administrative Order list of potentially liable parties for groundwater contamination for a portion of the Sauget Area 2 site. The

Unilateral Administrative Order encompasses the groundwater contamination releasing to the Mississippi River adjacent to Monsanto Chemical Company's (now known as Solutia's) former chemical waste landfill and the resulting impact area in the Mississippi River. Ameren is being asked to participate in response activities that involve the installation of a barrier wall around a chemical waste site with three recovery wells to divert groundwater flow. The projected cost for this remedy method is \$26 million. In November 2002, Ameren sent a letter to the EPA asserting its defenses to the Unilateral Administrative Order and requested its removal from the list of potentially responsible parties under the Unilateral Administrative Order. Solutia agreed to comply with the Unilateral Administrative Order. However, in December 2003, Solutia filed for bankruptcy protection and is seeking to discharge its environmental liabilities. As the status of future remediation at Sauget Area 2 or compliance with the Unilateral Administrative Order is uncertain, we are unable to predict the ultimate impact of the Sauget Area 2 site on our financial position, results of operations or liquidity.

In October 2002, Ameren submitted a corrective action plan to the Illinois Environmental Protection Agency (Illinois EPA) in accordance with permit conditions to address ground water issues associated with the recycle pond and ash ponds at the Duck Creek power plant facility. In January 2003, the Illinois EPA accepted portions of the plan but rejected other portions. Additional discussions with the Illinois EPA will be necessary to develop an acceptable plan. Ameren has a liability of \$8 million at December 31, 2003, included on its Consolidated Balance Sheet for the estimated cost of the remediation effort to treat and discharge the recycle system water in order to address these ground water issues. Future Ameren capital expenditures at Duck Creek will entail installation of a bypass water line and construction of a landfill and a new pond. Ameren estimates future capital expenditures for the indicated activities could range from \$19 million to \$30 million by 2008.

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

Waste Disposal

On July 30, 2002, the Illinois Attorney General's Office advised us that it would be commencing an enforcement action concerning an inactive waste disposal site near Coffeen, Illinois, which is the location of a disposal facility permitted by the Illinois EPA to receive fly ash from Ameren's Coffeen power plant. The Illinois Attorney General also notified the disposal facility's current and former owners as to the proposed enforcement action. The Attorney General advised that it may initiate an action under CERCLA (Superfund) to recover past costs incurred at the site (approximately \$0.3 million) and to obtain a declaratory judgment as to

liability for future costs. Neither Genco, the current owner of the Coffeen power plant, nor CIPS, the prior owner of the Coffeen power plant, owned or operated the disposal facility. We believe that this matter will not have a material adverse effect on Ameren's financial position, results of operations or liquidity.

ASBESTOS-RELATED LITIGATION

Ameren, UE, CIPS, Genco and CILCO have been named, along with numerous other parties, in a number of lawsuits which have been filed by certain plaintiffs claiming varying degrees of injury from asbestos exposure. Most have been filed in the Circuit Court of Madison County, Illinois. The number of total defendants named in each case is significant with as many as 110 parties named in a case to as few as six. However, the average number of parties is 60 in the cases that were pending as of December 31, 2003.

The claims filed against Ameren, UE, CIPS, Genco and CILCO allege injury from asbestos exposure during the plaintiffs' activities at our electric generating plants. In the case of CIPS, its former plants are now owned by Genco, and in the case of CILCO, most of its former plants are now owned by AERG. As a part of the transfer of ownership of the generating plants, the transferor (CIPS or CILCO) has contractually agreed to indemnify the transferee (Genco or AERG) for liabilities associated with asbestos-related claims arising from activities prior to the transfer. Each lawsuit seeks unspecified damages in excess of \$50,000, which, if proved, typically would be shared among the named defendants.

The following table presents the status of the asbestos-related lawsuits that have been filed against the Ameren Companies as of December 31, 2003:

	Total(a)	Specifically Named as Defendant				
		Ameren	UE	CIPS	Genco	CILCO
Filed	178	15	121	68	2	13
Settled	31	—	22	11	—	1
Dismissed	67	2	50	21	—	1
Pending	80	13	49	36	2	11

(a) Addition of the numbers in the individual columns does not equal the total column because some of the lawsuits name multiple Ameren entities as defendants.

Ameren believes that the final disposition of these proceedings will not have a material adverse effect on its financial position, results of operations or liquidity.

REGULATION

Regulatory changes enacted and being considered at the federal and state levels continue to change the structure of the utility industry and utility regulation, as well as encourage increased competition. At this time, we are unable to predict the impact of these changes on our future financial position, results of operations or liquidity. See Note 3 – Rate and Regulatory Matters for further information.

Note 15 – Callaway Nuclear Plant

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or 1/10 of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel. Pursuant to this Act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates from its Callaway Nuclear Plant. Electric utility rates charged to customers provide for recovery of such costs. The DOE is not expected to have its permanent storage facility for spent fuel available until at least 2015. UE has sufficient storage capacity at the Callaway Nuclear Plant until 2019 and has the capability for additional storage capacity through the licensed life of the plant. The delayed availability of the DOE's disposal facility is not expected to adversely affect the continued operation of the Callaway Nuclear Plant through its currently licensed life.

Electric utility rates charged to customers provide for the recovery of the Callaway Nuclear Plant decommissioning costs over the life of the plant, based on an assumed 40-year life, ending with expiration of the plant's operating license in 2024. The Callaway Nuclear Plant site is assumed to be decommissioned based on immediate dismantlement method and removal from service. Decommissioning costs, including decontamination, dismantling and site restoration, are estimated to be \$536 million in current year dollars and are expected to escalate approximately 3.5% per year through the end of decommissioning activity in 2033. Decommissioning costs are charged to cost of services used to establish electric rates for UE's customers and amounted to approximately \$7 million in each of the years 2003, 2002 and 2001. Every three years, the MoPSC and ICC require UE to file updated cost studies for decommissioning the Callaway Nuclear Plant, and electric rates may be adjusted at such times to reflect changed estimates. The latest studies were filed in 2002. Costs collected from customers are deposited in an external trust fund to provide for the Callaway Nuclear Plant's decommissioning. Fund earnings are expected to average approximately 8.6% annually through the date of decommissioning. If the assumed return on trust assets is not earned, we believe it is probable that any such earnings deficiency will be recovered in rates. The fair value of the nuclear decommissioning trust fund for UE's Callaway Nuclear Plant is reported in Nuclear Decommissioning Trust Fund in Ameren's Consolidated Balance Sheet. This amount is legally restricted to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the nuclear decommissioning trust fund and to the regulatory asset recorded in connection with the adoption of SFAS No. 143 beginning in 2003. Upon the completion of UE's transfer of its Illinois electric and gas utility businesses to CIPS, which is subject to the receipt of regulatory approvals, the assets and liabilities related to the Illinois portion of the decommissioning trust fund will be transferred to Missouri. See Note 3 – Rate and Regulatory Matters for further information.

Note 16 – Fair Value of Financial Instruments

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

CASH, TEMPORARY INVESTMENTS AND SHORT-TERM BORROWINGS

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

MARKETABLE SECURITIES

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

NUCLEAR DECOMMISSIONING TRUST FUND

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

PREFERRED STOCK OF SUBSIDIARIES

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

LONG-TERM DEBT

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

DERIVATIVE FINANCIAL INSTRUMENTS

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

The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2003 and 2002:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt and capital lease obligations (including current portion)	\$4,568	\$4,903	\$ 3,772	\$ 4,014
Preferred stock	203	186	193	170

We have investments in debt and equity securities that are held in trust funds for the purpose of funding the nuclear decommissioning of our Callaway Nuclear Plant. See Note 15 – Callaway Nuclear Plant for further information. We have classified these investments in debt and equity securities as available for sale and have recorded all such investments at their fair market value at December 31, 2003 and 2002. Investments by the nuclear decommissioning trust funds are allocated 60% to 70% to equity securities with the balance invested in fixed income securities. Fixed income investments are limited to U.S. government or

agency securities, municipal bonds or investment-grade corporate securities. The proceeds from the sale of investments were \$123 million in 2003 (2002 - \$141 million; 2001 - \$230 million). Using the specific identification method to determine cost, the gross realized gains on those sales were approximately \$1 million for 2003 (2002 - less than \$1 million; 2001 - \$4 million). Net realized and unrealized gains and losses are reflected in asset retirement obligations on our Consolidated Balance Sheet, which is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trusts could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in electric rates paid by customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund at December 31, 2003 and 2002:

	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
2003:				
Debt securities	\$ 62	\$ 2	\$ –	\$ 64
Equity securities	96	47	–	143
Cash equivalents	5	–	–	5
Total	\$163	\$49	\$ –	\$212
2002:				
Debt securities	\$ 57	\$ 4	\$ –	\$ 61
Equity securities	89	17	–	106
Cash equivalents	5	–	–	5
Total	\$151	\$21	\$ –	\$172

The following table presents the costs and fair values of investments in debt securities according to their contractual maturities at December 31, 2003:

	Cost	Fair Value
Less than 5 years	\$ 24	\$ 24
5 years to 10 years	22	23
Due after 10 years	16	17
Total	\$62	\$64

Note 17 – Segment Information

Ameren's reportable segment, Utility Operations, is comprised of its electric generation and electric and gas transmission and distribution operations. Ameren's reportable segment, Other, is comprised of the parent holding company, Ameren Corporation. As a result of the CILCORP acquisition, we modified our segment presentation in 2003 and have made reclassifications to prior periods to conform to current period presentation.

The accounting policies for segment data are the same as those described in Note 1 – Summary of Significant Accounting

Policies. Segment data includes intersegment revenues, as well as a charge for allocating costs of administrative support services to each of the operating companies, which, in each case, is eliminated upon consolidation. Ameren Services allocates administrative support services based on various factors, such as headcount, number of customers and total assets.

The table below presents information about the reported revenues, net income and total assets of Ameren for the years ended December 31, 2003, 2002, and 2001:

	Utility Operations	Other	Reconciling Items	Total
2003:				
Operating revenues	\$ 5,692	\$ –	\$(1,099) ^(a)	\$ 4,593
Net income	546	(22)	–	524
Total assets	13,472	761	–	14,233
2002:				
Operating revenues	\$ 4,912	\$ –	\$(1,071) ^(a)	\$ 3,841
Net income	384	(2)	–	382
Total assets	11,037	1,114	–	12,151
2001:				
Operating revenues	\$ 4,965	\$ –	\$(1,107) ^(a)	\$ 3,858
Net income	472	(3)	–	469
Total assets	9,939	462	–	10,401

(a) Elimination of intercompany revenues.

The following table presents specified items included in Ameren's segment profit (loss) for the years ended December 31, 2003, 2002, and 2001:

	Utility Operations	Other	Reconciling Items	Total
2003:				
Interest	\$344	\$29	\$(96) ^(a)	\$277
Depreciation and amortization	519	–	–	519
Income tax	305	(4)	–	301 ^(b)
2002:				
Interest	\$279	\$28	\$(93) ^(a)	\$214
Depreciation and amortization	431	–	–	431
Income tax	244	(7)	–	237
2001:				
Interest	\$259	\$13	\$(81) ^(a)	\$191
Depreciation and amortization	406	–	–	406
Income tax	306	(1)	–	305 ^(c)

(a) Elimination of intercompany interest charges.

(b) Does not include income tax expense related to the cumulative effect gain recognized upon adoption of SFAS No. 143.

(c) Does not include tax benefit related to the cumulative effect loss recognized upon adoption of SFAS No. 133.

All construction expenditures for the years ended December 31, 2003, 2002, and 2001, were in the Utility Operations segment.

Glossary of Terms and Abbreviations

AERG – AmerenEnergy Resources Generating Company, a subsidiary of CILCO, which operates a non rate-regulated electric generation business in Illinois and which was formerly known as Central Illinois Generation, Inc.

AES – The AES Corporation.

AFS – Ameren Energy Fuels and Services Company, a subsidiary of Resources Company, which procures fuel and gas and manages the related risks for the Ameren Companies.

Ameren – Ameren Corporation and its subsidiaries on a consolidated basis. When referring to financing or acquisition activities, Ameren is defined as Ameren Corporation, the parent.

Ameren Companies – The individual registrants within the Ameren consolidated group.

Ameren Energy – Ameren Energy, Inc., a subsidiary of Ameren Corporation, which serves as a power marketing and risk management agent for the Ameren Companies for transactions of primarily less than one year.

Ameren Services – Ameren Services Company, a subsidiary of Ameren Corporation, which provides a variety of support services to Ameren and its subsidiaries.

APB – Accounting Principles Board.

Btu – British Thermal Unit, which is a standard unit for measuring the quantity of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit.

CERCLA (Superfund) – Comprehensive Environmental Response Compensation Liability Act of 1980, which is federal environmental legislation that addresses remediation of contaminated sites.

CILCO – Central Illinois Light Company, a subsidiary of CILCORP, which operates a rate-regulated transmission and distribution business, an electric generation business, and a rate-regulated natural gas distribution business in Illinois as AmerenCILCO. CILCO owns all the common stock of AERG.

CILCORP – CILCORP Incorporated, a subsidiary of Ameren Corporation, which operates as a holding company for CILCO.

CIPS – Central Illinois Public Service Company, a subsidiary of Ameren Corporation, which operates a rate-regulated electric and natural gas transmission and distribution business in Illinois as AmerenCIPS.

Cooling Degree Days – The summation of positive differences between the mean daily temperature and the 65° Fahrenheit base. This statistic is useful as an indicator of demand for electricity for summer space cooling for residential and commercial customers.

CT – Combustion turbine generation equipment.

Development Company – Ameren Energy Development Company, a subsidiary of Resources Company, which develops and constructs generating facilities for Genco.

DOE – Department of Energy, a governmental agency of the United States of America.

DRPlus – Ameren Corporation's dividend reinvestment and stock purchase plan.

Dynergy – Dynergy Inc., the indirect parent company of Illinois Power.

EEL – Electric Energy, Inc., a 60%-owned subsidiary of Ameren Corporation, which is 40% owned by UE and 20% owned by Resources Company, which operates electric generation and transmission facilities in Illinois.

EITF – Emerging Issues Task Force, an organization that is designed to assist the FASB in improving financial reporting through the identification, discussion and resolution of financial issues within the framework of existing authoritative literature.

EPA – Environmental Protection Agency, a governmental agency of the United States of America.

ERISA – Employee Retirement Income Security Act of 1974, as amended.

FASB – Financial Accounting Standards Board, a rule-making organization that establishes financial accounting and reporting standards in the United States of America.

FERC – Federal Energy Regulatory Commission, a governmental agency of the United States of America that, among other things, regulates interstate transmission and wholesale sales of electricity and gas and related matters.

FIN – FASB Interpretation intended to clarify accounting pronouncements previously issued by the FASB.

Fitch – Fitch Ratings, a leading global rating agency.

GAAP – Generally accepted accounting principles in the United States of America.

Genco – Ameren Energy Generating Company, a subsidiary of Development Company, which operates a non rate-regulated electric generation business in Illinois and Missouri.

GridAmerica Companies – UE, CIPS, American Transmission Systems, Inc., a subsidiary of FirstEnergy Corp., and Northern Indiana Public Service Company, a subsidiary of NiSource, Incorporated.

Heating Degree Days – The summation of negative differences between the mean daily temperature and the 65° Fahrenheit base. This statistic is useful as an indicator of demand for electricity and natural gas for winter space heating for residential and commercial customers.

ICC – Illinois Commerce Commission, a state agency that regulates the Illinois utility businesses and operations of UE, CIPS and CILCO.

Illinois Customer Choice Law – Illinois Electric Service Customer Choice and Rate Relief Law of 1997, which provides for electric utility restructuring and introduces competition into the retail supply of electric energy in Illinois.

Illinois Power – Illinois Power Company, a wholly owned subsidiary of Ilinova Corporation, which is a subsidiary of Dynergy.

ITC – Independent Transmission Company.

Marketing Company – Ameren Energy Marketing Company, a subsidiary of Resources Company, which markets power for periods primarily over one year.

Medina Valley – AmerenEnergy Medina Valley Cogen (No. 4), LLC and its subsidiaries, which are subsidiaries of Resources Company, which indirectly own a 40 megawatt, gas-fired electric generation plant.

MGP – Manufactured Gas Plant.

Midwest ISO – Midwest Independent System Operator.

MMBtu – One million Btus.

Moody's – Moody's Investors Service, Inc., a leading global rating agency.

MoPSC – Missouri Public Service Commission, a state agency that regulates the Missouri utility business and operations of UE.

MTN – Medium-term note.

NOPR – Notice of Proposed Rulemaking issued by the FERC.

NO_x – Nitrogen oxide.

NRC – Nuclear Regulatory Commission, a governmental agency of the United States of America.

NSR – New Source Review programs under the federal Clean Air Act.

NYMEX – New York Mercantile Exchange.

OATT – Open Access Transmission Tariff.

OCI – Other Comprehensive Income (Loss) as defined by GAAP.

PGA – Purchased Gas Adjustment tariffs, which impact UE, CIPS and CILCO natural gas utility customers.

PUHCA – Public Utility Holding Company Act of 1935, as amended.

Resources Company – Ameren Energy Resources Company, a subsidiary of Ameren Corporation, which consists of non rate-regulated operations, including Development Company, Genco, Marketing Company, AFS and Medina Valley.

RTO – Regional Transmission Organization.

S&P – Standard and Poor's, a leading global rating agency.

SEC – Securities and Exchange Commission, a governmental agency of the United States of America.

SFAS – Statement of Financial Accounting Standards, the accounting and financial reporting rules issued by the FASB.

SO₂ – Sulfur dioxide.

UE – Union Electric Company, a subsidiary of Ameren Corporation, which operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois as AmerenUE.