Ameren Illinois Co
Form 10-K
February 24, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(X) Annual report pursuant to Section 13 or 15(d)

of the Securities Exchange Act of 1934

for the fiscal year ended December 31, 2010

OR

( ) Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to .

Commission File Number	Exact name of registrant as specified in its charter; State of Incorporation; Address and Telephone Number	IRS Employer Identification No.
1-14756	**Ameren Corporation** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-1723446
1-2967	**Union Electric Company** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-0559760
1-3672	**Ameren Illinois Company** (Illinois Corporation) 300 Liberty Street Peoria, Illinois 61602 (309) 677-5271	37-0211380
333-56594	**Ameren Energy Generating Company** (Illinois Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	37-1395586

Securities Registered Pursuant to Section 12(b) of the Securities Exchange Act of 1934:

The following security is registered pursuant to Section 12(b) of the Securities Exchange Act of 1934 and is listed on the New York Stock Exchange:

Registrant	Title of each class
Ameren Corporation	Common Stock, $0.01 par value per share

Securities Registered Pursuant to Section 12(g) of the Securities Exchange Act of 1934:

Registrant	Title of each class
Union Electric Company	Preferred Stock, cumulative, no par value, stated value $100 per share
Ameren Illinois Company	Preferred Stock, cumulative, $100 par value per share Depository Shares, each representing one-fourth of a share of 6.625% Preferred Stock, cumulative, $100 par value per share

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Ameren Energy Generating Company does not have securities registered under either Section 12(b) or 12(g) of the Securities Exchange Act of 1934.

Indicate by checkmark if each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

Ameren Corporation	Yes	(X)	No	( )
Union Electric Company	Yes	(X)	No	( )
Ameren Illinois Company	Yes	( )	No	(X)
Ameren Energy Generating Company	Yes	( )	No	(X)

Indicate by checkmark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

Ameren Corporation	Yes	( )	No	(X)
Union Electric Company	Yes	( )	No	(X)
Ameren Illinois Company	Yes	( )	No	(X)
Ameren Energy Generating Company	Yes	( )	No	(X)

Indicate by checkmark whether the registrants: (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Ameren Corporation	Yes	(X)	No	( )
Union Electric Company	Yes	(X)	No	( )
Ameren Illinois Company	Yes	(X)	No	( )
Ameren Energy Generating Company	Yes	(X)	No	( )

Indicate by checkmark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Ameren Corporation	(X)
Union Electric Company	(X)
Ameren Illinois Company	(X)
Ameren Energy Generating Company	(X)

Indicate by checkmark whether each registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Ameren Corporation	Yes	(X)	No	( )
Union Electric Company	Yes	( )	No	( )
Ameren Illinois Company	Yes	( )	No	( )
Ameren Energy Generating Company	Yes	( )	No	( )

Indicate by checkmark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Ameren Corporation	(X)	( )	( )	( )
Union Electric Company	( )	( )	(X)	( )
Ameren Illinois Company	( )	( )	(X)	( )
Ameren Energy Generating Company	( )	( )	(X)	( )

Indicate by checkmark whether each registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Ameren Corporation	Yes	( )	No	(X)
Union Electric Company	Yes	( )	No	(X)
Ameren Illinois Company	Yes	( )	No	(X)
Ameren Energy Generating Company	Yes	( )	No	(X)

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As of June 30, 2010, Ameren Corporation had 239,131,488 shares of its $0.01 par value common stock outstanding. The aggregate market value of these shares of common stock (based upon the closing price of the common stock on the New York Stock Exchange on that date) held by nonaffiliates was $5,684,155,470. The shares of common stock of the other registrants were held by affiliates as of June 30, 2010.

The number of shares outstanding of each registrant s classes of common stock as of January 31, 2011, was as follows:

Ameren Corporation	Common stock, $0.01 par value per share: 240,544,989
Union Electric Company	Common stock, $5 par value per share, held by Ameren Corporation (parent company of the registrant): 102,123,834
Ameren Illinois Company	Common stock, no par value, held by Ameren Corporation (parent company of the registrant): 25,452,373
Ameren Energy Generating Company	Common stock, no par value, held by Ameren Energy Resources Company, LLC (parent company of the registrant and subsidiary of Ameren Corporation): 2,000

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement of Ameren Corporation and portions of the definitive information statements of Union Electric Company and Ameren Illinois Company for the 2011 annual meetings of shareholders are incorporated by reference into Part III of this Form 10-K.

OMISSION OF CERTAIN INFORMATION

Ameren Energy Generating Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

This combined Form 10-K is separately filed by Ameren Corporation, Union Electric Company, Ameren Illinois Company and Ameren Energy Generating Company. Each registrant hereto is filing on its own behalf all of the information contained in this annual report that relates to such registrant. Each registrant hereto is not filing any information that does not relate to such registrant, and therefore makes no representation as to any such information.

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This report contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements should be read with the cautionary statements and important factors included on pages 3, 4 and 5 of this report under the heading Forward-looking Statements. Forward-looking statements are all statements other than statements of historical fact, including those statements that are identified by the use of the words anticipates, estimates, expects, intends, plans, predicts, projects, and simila expressions.

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GLOSSARY OF TERMS AND ABBREVIATIONS

We use the words our, we or us with respect to certain information that relates to all Ameren Companies, as defined below. When appropriate, subsidiaries of Ameren are named specifically as we discuss their various business activities.

2007 Illinois Electric Settlement Agreement A comprehensive settlement of issues in Illinois arising out of the end of ten years of frozen electric rates, effective January 2, 2007. The settlement, which became effective in 2007, was designed to avoid new rate rollback and freeze legislation and legislation that would impose a tax on electric generation in Illinois. The settlement addressed the issue of power procurement, and it included a comprehensive rate relief and customer assistance program.

2009 Illinois Credit Agreement Ameren s and AIC s $800 million senior secured credit agreement, which terminated on September 10, 2010.

2009 Multiyear Credit Agreement Ameren s, UE s and Genco s $1.15 billion credit agreement, which terminated on September 10, 2010. Collectively, this agreement and the 2009 Supplemental Credit Agreement are referred to herein as the 2009 Multiyear Credit Agreements.

2009 Supplemental Credit Agreement Ameren s, UE s and Genco s $150 million supplemental credit agreement to the 2009 Multiyear Credit Agreement. This agreement expired in July 2010.

2010 Credit Agreements The 2010 Genco Credit Agreement, the 2010 Illinois Credit Agreement, and the 2010 Missouri Credit Agreement, collectively.

2010 Genco Credit Agreement On September 10, 2010, Ameren and Genco entered into a $500 million multiyear senior unsecured revolving credit facility. This agreement expires on September 10, 2013.

2010 Illinois Credit Agreement On September 10, 2010, Ameren and AIC entered into an $800 million multiyear senior unsecured credit agreement. This agreement expires on September 10, 2013.

2010 Missouri Credit Agreement On September 10, 2010, Ameren and UE entered into an $800 million multiyear senior unsecured revolving credit facility. This agreement expires on September 10, 2013, subject to UE s borrowing sublimit extensions.

AERG AmerenEnergy Resources Generating Company, a CILCO subsidiary until October 1, 2010, that operates a merchant electric generation business in Illinois. On October 1, 2010, AERG stock was distributed to Ameren and subsequently contributed by Ameren to Resources Company, which resulted in AERG becoming a subsidiary of Resources Company.

AFS Ameren Energy Fuels and Services Company, a Resources Company subsidiary that procured fuel and natural gas and managed the related risks for the Ameren Companies prior to January 1, 2011. Effective January 1, 2011, the functions previously performed by AFS are performed within the Ameren Missouri, Ameren Illinois and Merchant Generation business segments.

AIC Ameren Illinois Company, an Ameren Corporation subsidiary that operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. This

business consists of the combined rate-regulated electric and natural gas transmission and distribution businesses operated by CIPS, CILCO and IP before the AIC Merger. References to AIC prior to the AIC Merger refer collectively to the rate-regulated electric and natural gas transmission and distribution businesses of CIPS, CILCO and IP. Immediately after the AIC Merger, AIC distributed the common stock of AERG to Ameren Corporation. AERG is treated as a discontinued operation within AIC s financial statements. AIC operates its business in Illinois as Ameren Illinois.

AIC Merger On October 1, 2010, CILCO and IP merged with and into CIPS, with the surviving corporation renamed Ameren Illinois Company.

Ameren Ameren Corporation and its subsidiaries on a consolidated basis. In references to financing activities, acquisition activities, or liquidity arrangements, Ameren is defined as Ameren Corporation, the parent.

Ameren Companies The individual registrants within the Ameren consolidated group.

Ameren Illinois A financial reporting segment consisting of AIC s rate-regulated businesses. AIC also operates its business in Illinois as Ameren Illinois.

Ameren Missouri A financial reporting segment consisting of UE s rate-regulated businesses. UE also operates its business in Missouri as Ameren Missouri.

Ameren Services Ameren Services Company, an Ameren Corporation subsidiary that provides support services to Ameren and its subsidiaries.

AMIL The MISO balancing authority area operated by Ameren, which includes the load of AIC and the generating assets of Genco (excluding EEI and Genco s Elgin CT facility) and AERG.

AMMO The MISO balancing authority area operated by Ameren, which includes the load and generating assets of UE.

AMT Alternative minimum tax.

ARO Asset retirement obligations.

ATX Ameren Transmission Company, an Ameren Corporation subsidiary dedicated to electric transmission infrastructure investment.

ATXI Ameren Transmission Company of Illinois, an Ameren Corporation subsidiary that is engaged in the construction and operation of electric transmission assets in Illinois.

Baseload The minimum amount of electric power delivered or required over a given period of time at a steady rate.

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

CAIR Clean Air Interstate Rule.

Capacity factor A percentage measure that indicates how much of an electric power generating unit s capacity was used during a specific period.

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CATR Clean Air Transport Rule.

CILCO Central Illinois Light Company, a former Ameren Corporation subsidiary that operated a rate-regulated electric transmission and distribution business, a merchant electric generation business through AERG, and a rate-regulated natural gas transmission and distribution business, all in Illinois, before the AIC Merger. CILCO owned all of the common stock of AERG and included AERG within its consolidated financial statements. Immediately after the AIC Merger, AIC distributed the common stock of AERG to Ameren Corporation. AERG is treated as a discontinued operation within AIC s financial statements.

CILCORP CILCORP Inc., a former Ameren Corporation subsidiary that operated as a holding company for CILCO and its merchant generation subsidiary. On March 4, 2010, CILCORP merged with and into Ameren.

CIPS Central Illinois Public Service Company, an Ameren Corporation subsidiary, renamed Ameren Illinois Company at the effective date of the AIC Merger, that operates a rate-regulated electric and natural gas transmission and distribution business, all in Illinois.

CO_2 Carbon dioxide.

COLA Combined nuclear plant construction and operating license application.

Cooling degree-days The summation of positive differences between the mean daily temperature and a 65-degree Fahrenheit base. This statistic is useful for estimating electricity demand by residential and commercial customers for summer cooling.

CT Combustion turbine electric generation equipment used primarily for peaking capacity.

Development Company Ameren Energy Development Company, which was a Resources Company subsidiary and parent of Genco, Marketing Company, AFS, and Medina Valley. It was eliminated in an internal reorganization in February 2008.

DOE Department of Energy, a U.S. government agency.

DRPlus Ameren Corporation s dividend reinvestment and direct stock purchase plan.

Dth (dekatherm) One million Btus of natural gas.

EEI Electric Energy, Inc., an 80%-owned Genco subsidiary that operates merchant electric generation facilities and FERC-regulated transmission facilities in Illinois. Before February 29, 2008, EEI was 40% owned by UE and 40% owned by Development Company. On February 29, 2008, UE s 40% ownership interest and Development Company s 40% ownership interest were transferred to Resources Company. Effective January 1, 2010, in an internal reorganization, Resources Company contributed its 80% ownership interest in EEI to its subsidiary, Genco. The remaining 20% ownership interest is owned by Kentucky Utilities Company, a nonaffiliated entity.

EPA Environmental Protection Agency, a U.S. government agency.

Equivalent availability factor A measure that indicates the percentage of time an electric power generating unit was available for service during a period.

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

ESP Early Site Permit.

Exchange Act Securities Exchange Act of 1934, as amended.

FAC A fuel and purchased power cost recovery mechanism that allows UE to recover, through customer rates, 95% of changes in fuel (coal, coal transportation, natural gas for generation, and nuclear) and purchased power costs, net of off-system revenues, including MISO costs and revenues, greater or less than the amount set in base rates, without a traditional rate proceeding.

FASB Financial Accounting Standards Board, a rulemaking organization that establishes financial accounting and reporting standards in the United States.

FERC The Federal Energy Regulatory Commission, a U.S. government agency.

Fitch Fitch Ratings, a credit rating agency.

FTRs Financial transmission rights, financial instruments that entitle the holder to pay or receive compensation for certain congestion-related transmission charges between two designated points.

Fuelco Fuelco LLC, a limited liability company that provides nuclear fuel management and services to its members. The members are UE, Luminant, and Pacific Gas and Electric Company.

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

Genco Ameren Energy Generating Company, a Resources Company subsidiary that operates a merchant electric generation business in Illinois and Missouri and holds an 80% ownership interest in EEI.

Gigawatthour One thousand megawatthours.

Heating degree-days The summation of negative differences between the mean daily temperature and a 65- degree Fahrenheit base. This statistic is useful as an indicator of demand for electricity and natural gas for winter space heating by residential and commercial customers.

IBEW International Brotherhood of Electrical Workers, a labor union.

ICC Illinois Commerce Commission, a state agency that regulates Illinois utility businesses, including ATXI and AIC.

Illinois Customer Choice Law Illinois Electric Service Customer Choice and Rate Relief Law of 1997, which provided for electric utility restructuring; it was designed to introduce competition into the retail supply of electric energy in Illinois.

Illinois EPA Illinois Environmental Protection Agency, a state government agency.

IP Illinois Power Company, a former Ameren Corporation subsidiary that operated a rate-regulated electric and natural gas transmission and distribution business, all in Illinois, before the AIC Merger.

IPA Illinois Power Agency, a state government agency that has broad authority to assist in the procurement of electric power for residential and nonresidential customers.

ISRS Infrastructure system replacement surcharge, which is a cost recovery mechanism in Missouri that allows UE to recover gas infrastructure replacement costs from utility customers without filing a traditional rate case.

IUOE International Union of Operating Engineers, a labor union.

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Kilowatthour A measure of electricity consumption equivalent to the use of 1,000 watts of power over one hour.

LIUNA Laborers International Union of North America, a labor union.

MACT Maximum Achievable Control Technology.

Marketing Company Ameren Energy Marketing Company, a Resources Company subsidiary that markets power for Genco, AERG, EEI and Medina Valley.

Medina Valley AmerenEnergy Medina Valley Cogen LLC, a Resources Company subsidiary, which owns a 40-megawatt gas-fired electric generation plant.

Megawatthour One thousand kilowatthours.

Merchant Generation A financial reporting segment consisting primarily of the operations or activities of Resources Company, including Genco, Genco s 80% ownership interest in EEI, AERG, Medina Valley and Marketing Company.

MGP Manufactured gas plant.

MISO Midwest Independent Transmission System Operator, Inc., an RTO.

MISO Energy and Operating Reserves Market A market that uses market-based pricing, which takes into account transmission congestion and line losses, to compensate market participants for power and ancillary services.

Missouri Environmental Authority Environmental Improvement and Energy Resources Authority of the state of Missouri, a governmental body authorized to finance environmental projects by issuing tax-exempt bonds and notes.

Mmbtu One million Btus.

Money pool Borrowing agreements among Ameren and its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools maintained for rate-regulated and non-rate-regulated business are referred to as the utility money pool and the non-state-regulated subsidiary money pool, respectively.

Moody s Moody s Investors Service Inc., a credit rating agency.

MoPSC Missouri Public Service Commission, a state agency that regulates Missouri utility businesses, including UE.

MPS Multi-Pollutant Standard, an agreement, as amended, reached in 2006 among Genco, AERG, EEI and the Illinois EPA, which was codified in Illinois environmental regulations.

MTM Mark-to-market.

MW Megawatt.

Native load Wholesale customers and end-use retail customers, whom we are obligated to serve by statute, franchise, contract, or other regulatory requirement.

NCF&O National Congress of Firemen and Oilers, a labor union.

NO_x Nitrogen oxide.

Noranda Noranda Aluminum, Inc.

NPNS Normal purchases and normal sales.

NRC Nuclear Regulatory Commission, a U.S. government agency.

NSPS New Source Performance Standards, a provision under the Clean Air Act.

NSR New Source Review provisions of the Clean Air Act, which include Nonattainment New Source Review and Prevention of Significant Deterioration regulations.

NYMEX New York Mercantile Exchange.

NYSE New York Stock Exchange, Inc.

OATT Open Access Transmission Tariff.

OCI Other comprehensive income (loss) as defined by GAAP.

Off-system revenues Revenues from other than native load sales.

OTC Over-the-counter.

PGA Purchased Gas Adjustment tariffs, which allow the passing through of the actual cost of natural gas to utility customers.

PJM PJM Interconnection LLC.

PUHCA 2005 The Public Utility Holding Company Act of 2005, enacted as part of the Energy Policy Act of 2005, effective February 8, 2006.

Regulatory lag The effect of adjustments to retail electric and natural gas rates being based on historic cost and revenue levels. Rate increase requests can take up to 11 months to be acted upon by the MoPSC and the ICC. As a result, revenue increases authorized by regulators will lag behind changing costs and revenue when based on historical periods.

Resources Company Ameren Energy Resources Company, LLC, an Ameren Corporation subsidiary that consists of non-rate-regulated operations, including Genco, Genco s 80% ownership interest in EEI, AERG, Marketing Company and Medina Valley. On October 1, 2010, AERG stock was distributed to Ameren, which then contributed it to Resources Company, thereby making AERG a subsidiary of Resources Company.

RFP Request for proposal.

RTO Regional Transmission Organization.

S&P Standard & Poor s Ratings Services, a credit rating agency that is a division of The McGraw-Hill Companies, Inc.

SEC Securities and Exchange Commission, a U.S. government agency.

SERC SERC Reliability Corporation, one of the regional electric reliability councils organized for coordinating the planning and operation of the nation s bulk power supply.

SO_2 Sulfur dioxide.

UA United Association of Plumbers and Pipefitters, a labor union.

UE Union Electric Company, an Ameren Corporation subsidiary that operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri, doing business as Ameren Missouri.

VIE Variable-interest entity.

FORWARD-LOOKING STATEMENTS

Statements in this report not based on historical facts are considered forward-looking and, accordingly, involve

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risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there is no assurance that the expected results will be achieved. These statements include (without limitation) statements as to future expectations, beliefs, plans, strategies, objectives, events, conditions, and financial performance. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause actual results to differ materially from those anticipated. The following factors, in addition to those discussed under Risk Factors and elsewhere in this report and in our other filings with the SEC, could cause actual results to differ materially from management expectations suggested in such forward-looking statements:

regulatory, judicial, or legislative actions, including changes in regulatory policies and ratemaking determinations, such as the outcome of the pending UE electric rate proceeding and the AIC electric and natural gas rate proceeding; the court appeals and regulatory proceedings related to UE s 2009 and 2010 electric rate orders and the court appeals related to AIC s 2010 electric and natural gas rate order; and future regulatory, judicial, or legislative actions that seek to limit or reverse rate increases;
the effects of, or changes to, the Illinois power procurement process;
changes in laws and other governmental actions, including monetary, fiscal, and tax policies;
changes in laws or regulations that adversely affect the ability of electric distribution companies and other purchasers of wholesale electricity to pay their suppliers, including UE and Marketing Company;
the effects of increased competition in the future due to, among other things, deregulation of certain aspects of our business at both the state and federal levels, and the implementation of deregulation, such as occurred when the electric rate freeze and power supply contracts expired in Illinois at the end of 2006;
the effects on demand for our services resulting from technological advances, including advances in energy efficiency and distributed generation sources, which generate electricity at the site of consumption;
increasing capital expenditure and operating expense requirements and our ability to recover these costs in a timely fashion in light of regulatory lag;
the effects of participation in, or potential withdrawal from, MISO;
the cost and availability of fuel such as coal, natural gas, and enriched uranium used to produce electricity; the cost and availability of purchased power and natural gas for distribution; and the level and volatility of future market prices for such commodities, including the ability to recover the costs for such commodities;
the effectiveness of our risk management strategies and the use of financial and derivative instruments;
the level and volatility of future prices for power in the Midwest;
business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products;
disruptions of the capital markets or other events that make the Ameren Companies access to necessary capital, including short-term credit and liquidity, impossible, more difficult, or more costly;
our assessment of our liquidity;
the impact of the adoption of new accounting guidance and the application of appropriate technical accounting rules and guidance;
actions of credit rating agencies and the effects of such actions;
the impact of weather conditions and other natural phenomena on us and our customers;
the impact of system outages;
generation, transmission, and distribution asset construction, installation, performance, and cost recovery;
the extent to which UE prevails in its claims against insurers in connection with its Taum Sauk pumped-storage hydroelectric plant incident;
the extent to which UE is permitted by its regulators to recover in rates (i) certain of the Taum Sauk rebuild costs not covered by insurance and (ii) investments made in connection with a proposed second unit at its Callaway nuclear plant;
impairments of long-lived assets, intangible assets, or goodwill;
operation of UE s nuclear power facility, including planned and unplanned outages, and decommissioning costs;
the effects of strategic initiatives, including mergers, acquisitions and divestitures;
the impact of current environmental regulations on utilities and power generating companies and the expectation that more stringent requirements, including those related to greenhouse gases, other emissions, and energy efficiency, will be enacted over time, which could limit or terminate the operation of certain of our generating units, increase our costs, result in an impairment of our assets, reduce our customers demand for electricity or natural gas, or otherwise have a negative financial effect;
the impact of complying with renewable energy portfolio requirements in Missouri;
labor disputes, work force reductions, future wage and employee benefits costs, including changes in discount rates and returns on benefit plan assets;
the inability of our counterparties and affiliates to meet their obligations with respect to contracts, credit facilities, and financial instruments;
the cost and availability of transmission capacity for the energy generated by the Ameren Companies facilities or required to satisfy energy sales made by the Ameren Companies;

legal and administrative proceedings; and
acts of sabotage, war, terrorism, or intentionally disruptive acts.

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

PART I

ITEM 1. BUSINESS.

GENERAL

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005 administered by FERC. Ameren was formed in 1997 by the merger of UE and CIPSCO Inc. Ameren acquired CILCORP in 2003 and IP in 2004. Ameren s primary assets are the common stock of its subsidiaries, including UE, AIC and Genco. Ameren s subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. These subsidiaries operate, as the case may be, rate-regulated electric generation, transmission, and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant generation businesses in Missouri and Illinois. Dividends on Ameren s common stock and the payment of other expenses by Ameren depend on distributions made to it by its subsidiaries. Below is a summary description of UE, AIC and Genco. A more detailed description can be found in Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report.

- UE operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri.
- AIC operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.
- Genco operates a merchant electric generation business in Illinois and Missouri.

As part of an internal reorganization, Resources Company transferred its 80% ownership interest in EEI to Genco, through a capital contribution, on January 1, 2010.

On October 1, 2010, after receiving all necessary approvals, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed a two-step corporate internal reorganization. The first step of the reorganization was the AIC Merger. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren (the AERG distribution) and the subsequent contribution by Ameren of the AERG stock to Resources Company. For additional information regarding the corporate reorganization, see Note 16 Corporate Reorganization and Discontinued Operations under Part II, Item 8, of this report.

The following table presents our total employees at December 31, 2010:

Ameren[(a)]	9,474
UE	4,372
AIC	2,752
Genco	695

(a) Total for Ameren includes Ameren registrant and nonregistrant subsidiaries.

As of January 1, 2011, the IBEW, the IUOE, the LIUNA, the NCF&O and the UA labor unions collectively represented about 59% of Ameren s total employees. They represented 64% of the employees at UE, 67% at AIC, and 67% at Genco. All collective bargaining agreements that expired in 2010 were renegotiated and ratified. The collective bargaining agreements have three- to five-year terms, and expire between 2011 and 2013. Several collective bargaining agreements between Ameren subsidiaries and the IBEW, IUOE, the LIUNA, NCF&O and the UA labor unions, covering approximately 925 employees, expire throughout 2011.

For additional information about the development of our businesses, our business operations, and factors affecting our operations and financial position, see Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report and Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report.

BUSINESS SEGMENTS

Ameren has three reportable segments: Ameren Missouri, Ameren Illinois, and Merchant Generation. See Note 18 Segment Information under Part II, Item 8, of this report for additional information on reporting segments.

RATES AND REGULATION

Rates

The rates that UE and AIC are allowed to charge for their utility services significantly influence the results of operations, financial position, and liquidity of these companies and Ameren. The electric and natural gas utility industry is highly regulated. The utility rates charged to UE and AIC customers are determined, in large part, by governmental entities, including the MoPSC, the ICC, and FERC. Decisions by these entities are influenced by many factors, including the cost of providing service, the prudency of expenditures, the quality of service, regulatory staff knowledge and experience, economic conditions, public policy, and social and political views. Decisions made by these governmental entities regarding rates are largely outside of UE s and AIC s control. These decisions, as well as the regulatory lag involved in filing and getting new rates approved, could have a material impact on the results of operations, financial position, and liquidity of Ameren, UE and AIC. Rate orders are also subject to appeal and stay requests, which create additional uncertainty as to the rates UE and AIC are ultimately allowed to charge for their services.

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The ICC regulates rates and other matters for AIC and AITX. The MoPSC regulates rates and other matters for UE. The FERC regulates UE, AIC, Genco, and AITX as to their ability to charge market-based rates for the sale and transmission of energy in interstate commerce and various other matters discussed below under General Regulatory Matters.

About 46% of Ameren s electric and 15% of its gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2010. About 31% of Ameren s electric and 85% of its gas operating revenues were subject to regulation by the ICC in the year ended December 31, 2010. Wholesale revenues for UE, Genco and AERG are subject to FERC regulation, but not subject to direct MoPSC or ICC regulation.

Ameren Missouri (UE)

Electric

About 98% of UE s electric operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2010. Beginning March 1, 2009, UE s retail electric rates include a FAC that allows billing adjustments for changes in prudently incurred fuel and purchased power costs. On May 28, 2010, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $230 million. This order allowed UE to continue to use the regulatory tracking mechanisms for vegetation management and infrastructure costs and pension and postretirement benefit costs. See below for cost recovery of energy efficiency programs. UE s 2009 and 2010 electric rate orders are still subject to court appeals.

On September 3, 2010, UE filed a request with the MoPSC to increase its annual revenues for electric service by approximately $263 million. Approximately $110 million of the request relates to recovery of the cost of installing and operating two scrubbers at UE s Sioux plant. Also included in this requested increase is a $73 million anticipated increase in normalized net fuel costs above the net fuel costs included in base rates previously authorized by the MoPSC in its May 2010 electric rate order. Absent initiation of this general rate proceeding, 95% of this amount would have been reflected in rate adjustments implemented under UE s FAC. Capital additions relating to enhancements at the rebuilt Taum Sauk facility were also included in the increase request. As a part of its filing, UE also requested that the MoPSC approve the implementation of an infrastructure investment tracking mechanism as well as enhanced energy efficiency cost recovery. UE also requested continued use of its existing FAC, vegetation management and infrastructure cost tracker, and the regulatory tracking mechanism for pension and postretirement benefit costs the MoPSC previously authorized in earlier electric rate orders. In February 2011, the MoPSC staff responded to the UE request for an electric service rate increase. The MoPSC staff recommended an increase to UE s annual revenues of between $45 million and $99 million based on a return on equity of 8.25% to

9.25%. Included in this recommendation was approximately $50 million of increases in normalized net fuel costs and $32 million of asset disallowances relating to the Sioux plant scrubbers. Other parties also made recommendations through testimony filed in this case.

FERC regulates the rates charged and the terms and conditions for electric transmission services. Each RTO separately files a regional transmission tariff for approval by FERC. All transmission service within that RTO is then subjected to that tariff. As a member of MISO, UE s transmission rate is calculated in accordance with the MISO tariff rate formula. The transmission rate is updated in June of each year based on UE s filing with FERC. This rate is charged directly to wholesale customers. This rate is not directly charged to Missouri retail customers because in Missouri the MoPSC includes transmission-related costs in setting bundled retail rates.

Natural Gas

All of UE s natural gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2010. In January 2011, the MoPSC approved a stipulation and agreement that allows UE to increase annual natural gas revenues by $9 million resolving a June 2010 rate increase request. The new rates became effective on February 20, 2011. As part of the stipulation and agreement, UE agreed not to file a separate natural gas rate increase request before December 31, 2012; however, UE can file a combined natural gas and electric rate case before that date. Further, this agreement does not prevent UE from filing to recover infrastructure replacement costs through an ISRS during this moratorium. The return on equity to be used by UE for purposes of an ISRS tariff filing is 10%.

If certain criteria are met, UE s natural gas rates may be adjusted without a traditional rate proceeding. PGA clauses permit prudently incurred natural gas costs to be passed directly to the consumer. The ISRS also permits prudently incurred natural gas infrastructure replacement costs to be passed directly to the consumer.

For additional information on Missouri rate matters, including UE s 2011 natural gas rate order, UE s pending electric rate case, and UE s 2009 and 2010 electric rate orders and related court appeals and regulatory proceedings, see Results of Operations and Outlook in Management s

Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, and Note 2 Rate and Regulatory Matters, and Note 15 Commitments and Contingencies under Part II, Item 8, of this report.

Ameren Illinois (AIC)

All of AIC s electric and natural gas operating revenues were subject to regulation by the ICC or FERC in the year ended December 31, 2010.

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Under the Illinois Customer Choice Law, all electric customers in Illinois may choose their own electric energy provider. However, AIC is required to serve as the provider of last resort (POLR) for electric customers within its territory who have not chosen an alternative retail electric supplier. AIC s obligation to provide full requirements electric service, including power supply, as a POLR varies by customer size. AIC is not required to offer fixed-priced electric service to customers with electric demands of 400 kilowatts or greater, as the market for service to this group of customers has been declared competitive. Power procurement costs incurred by AIC are passed directly to its customers through a cost recovery mechanism.

In April 2010, the ICC issued a rate order for AIC, which was amended in May 2010, that approved a net increase in annual revenues for electric delivery service of $35 million and a net decrease in annual revenues for natural gas delivery service of $20 million. The rate changes became effective in May 2010. The ICC order confirmed the previously approved 80% allocation of fixed non-volumetric residential and commercial natural gas customer charges, and approved a higher percentage of recovery of fixed non-volumetric electric residential and commercial customer charges. The percentage of costs to be recovered through fixed non-volumetric electric residential and commercial customer and meter charges increased from 27% to 40%. AIC and certain intervenors were granted a rehearing with the ICC. In November 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the net $15 million increase authorized in the ICC s May 2010 amended rate order. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues became effective on November 19, 2010.

AIC filed a request with the ICC in February 2011 to increase its annual revenues for electric and natural gas delivery service by $60 million and $51 million, respectively. In an attempt to limit regulatory lag, AIC is using a future test year, 2012, in this rate request. Additionally, AIC is requesting a rider mechanism for its pension costs and the continuation of existing riders described below, including cost recovery mechanisms for energy efficiency costs. The requested pension cost rider mechanism would allow AIC to recover from or refund to customers any difference between pension expense incurred and the amount allowed in rates annually without a formal regulatory proceeding.

AIC has a tariff rider to recover the costs of asbestos-related litigation claims, subject to the following terms: 90% of cash expenditures in excess of the amount included in base electric rates are recovered from a trust fund established when Ameren acquired IP. At December 31, 2010, the trust fund balance was $23 million, including accumulated interest. If cash expenditures are less than the amount in base rates, AIC will contribute 90% of the difference to the fund. Once the trust fund is depleted, 90% of allowed cash expenditures in excess of base rates will be recovered through charges assessed to customers under

the tariff rider. Following the AIC Merger, this rider is only applicable for claims that occurred within IP s historical service territory. Similarly, the rider will seek recovery only from customers within IP s historical service territory.

In 2009, a new law became effective in Illinois that allows electric and natural gas utilities to recover through a rate adjustment the difference between their actual bad debt expense and the bad debt expense included in their base rates. In February 2010, the ICC approved AIC s electric and natural gas rate adjustment tariffs to recover bad debt expense not recovered in base rates.

If certain criteria are met, AIC s natural gas rates may be adjusted without a traditional rate proceeding. PGA clauses permit prudently incurred natural gas costs to be passed directly to the consumer.

FERC regulates the rates charged and the terms and conditions for electric transmission services. Each RTO separately files a regional transmission tariff for approval by FERC. All transmission service within that RTO is then subjected to that tariff. As a member of MISO, AIC s transmission rate is calculated in accordance with the MISO tariff rate formula. The transmission rate is updated in June of each year based on AIC s filings with FERC filings. This rate is charged directly to wholesale customers and alternative retail electric suppliers. For retail customers who have not chosen an alternative retail electric supplier, the transmission rate is collected through a rider mechanism.

For additional information on Illinois rate matters, including AIC s currently pending electric and natural gas rate cases, see Results of Operations and Outlook in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, and Note 2 Rate and Regulatory Matters, and Note 15 Commitments and Contingencies under Part II, Item 8, of this report.

Merchant Generation

Merchant Generation revenues are determined by market conditions and contractual arrangements. We expect the Merchant Generation fleet of assets to have 6,263 megawatts of capacity available for the 2011 peak summer electrical demand. As discussed below, Genco and AERG sell all of their power and capacity to Marketing Company through power supply agreements. Marketing Company attempts to optimize the value of those assets and mitigate risks through a variety of hedging techniques, including wholesale sales of capacity and energy, retail sales in the non-rate-regulated Illinois market, spot market sales primarily in MISO and PJM, and financial transactions. Marketing Company enters into long-term and short-term contracts. Marketing Company s counterparties include cooperatives, municipalities, commercial and industrial customers, power marketers, MISO, PJM and investor-owned utilities, such as AIC. For additional information on Marketing Company s hedging activities and Marketing Company s sales to AIC, see Outlook in Management s

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Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7 and Note 7 Derivative Financial Instruments and Note 14 Related Party Transactions under Part II, Item 8, of this report.

General Regulatory Matters

UE and AIC must receive FERC approval to issue short-term debt securities and to conduct certain acquisitions, mergers and consolidations involving electric utility holding companies having a value in excess of $10 million. In addition, these Ameren utilities must receive authorization from the applicable state public utility regulatory agency to issue stock and long-term debt securities (with maturities of more than 12 months) and to conduct mergers, affiliate transactions, and various other activities. Genco and AERG are subject to FERC s jurisdiction when they issue any securities.

Under PUHCA 2005, FERC and any state public utility regulatory agencies may access books and records of Ameren and its subsidiaries that are determined to be relevant to costs incurred by Ameren s rate-regulated subsidiaries with respect to jurisdictional rates. PUHCA 2005 also permits the MoPSC and the ICC to request that FERC review cost allocations by Ameren Services to other Ameren companies.

Operation of UE s Callaway nuclear plant is subject to regulation by the NRC. Its facility operating license expires on June 11, 2024. UE intends to submit a license extension application with the NRC to extend the plant s operating license to 2044. UE s Osage hydroelectric plant and UE s Taum Sauk pumped-storage hydroelectric plant, as licensed projects under the Federal Power Act, are subject to FERC regulations affecting, among other things, the general operation and maintenance of the projects. The license for UE s Osage hydroelectric plant expires on March 30, 2047. In June 2008, UE filed a relicensing application with FERC to operate its Taum Sauk pumped-storage hydroelectric facility for another 40 years. The existing FERC license expired on June 30, 2010. On July 2, 2010, UE received a license extension that allows Taum Sauk to continue operations until FERC issues a new license. UE conducted studies using current field data and submitted the study results to multiple state and federal agencies in February 2011. UE anticipates filing the study results with FERC in the spring of 2011. A FERC order is expected after a review of the study results is completed; however, we cannot predict the ultimate outcome of the order. Taum Sauk returned to service in April 2010 after the plant was rebuilt following the breach of its upper reservoir in December 2005. UE s Keokuk plant and its dam, in the Mississippi River between Hamilton, Illinois, and Keokuk, Iowa, are operated under authority granted by an Act of Congress in 1905.

For additional information on regulatory matters, see Note 2 Rate and Regulatory Matters and Note 15 Commitments and Contingencies under Part II, Item 8, of this report, which include a discussion about the December 2005 breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric plant.

Environmental Matters

Certain of our operations are subject to federal, state, and local environmental statutes or regulations relating to the safety and health of personnel, the public, and the environment. These environmental statutes and regulations include requirements for identification, generation, storage, handling, transportation, disposal, recordkeeping, labeling, reporting, and emergency response in connection with hazardous and toxic materials; safety and health standards; and environmental protection requirements, including standards and limitations relating to the discharge of air and water pollutants and the management of waste and byproduct materials. Failure to comply with those statutes or regulations could have material adverse effects on us. We could be subject to criminal or civil penalties by regulatory agencies or we could be ordered by the courts to pay private parties. Except as indicated in this report, we believe that we are in material compliance with existing statutes and regulations.

In addition to existing laws and regulations governing our facilities, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren, UE and Genco, that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; revised ambient air quality standards for SO_2 and NO_x emissions, lowering the existing ozone ambient air quality standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is also expected to propose new regulations under the Clean Water Act that could require significant capital expenditures, such as new water intake structures or cooling towers at our power plants, and a MACT standard for the control of hazardous air pollutants, such as mercury and acid gases from power plants. Such new regulations may be challenged with lawsuits, so the timing of their ultimate implementation is uncertain. Although many details of these future regulations are unknown, the combined effect of the new and proposed environmental regulations may result in significant capital expenditures or increased operating costs over the next five to eight years for Ameren, UE and Genco. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. As a result, these regulations could require us to close or to significantly alter the operation of our generating facilities, which could have an adverse effect on our results of operations, financial position, and liquidity.

For additional discussion of environmental matters, including NO_x, SO_2, and mercury emission reduction requirements, global climate change, remediation efforts, UE s receipt in January 2010 of a Notice of Violation from the EPA alleging violations of the Clean Air Act s NSR and Title V Programs, and the complaint filed by the EPA

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against UE in January 2011 alleging violation of the Clean Air Act and Missouri law in performing projects at UE s Rush Island coal-fired generating facility, see Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 15 Commitments and Contingencies under Part II, Item 8, of this report.

TRANSMISSION AND SUPPLY OF ELECTRIC POWER

Ameren owns an integrated transmission system that comprises the transmission assets of UE, AIC and ATXI. Ameren also operates two balancing authority areas, AMMO (which includes UE) and AMIL (which includes AIC, ATXI, Genco, excluding EEI and Genco s Elgin CT facility, and AERG). During 2010, the peak demand in AMMO was 8,797 MW and in AMIL was 9,166 MW. The Ameren transmission system directly connects with 15 other balancing authority areas for the exchange of electric energy.

UE, AIC and ATXI are transmission-owning members of MISO. Transmission service on the Ameren transmission systems is provided pursuant to the terms of the MISO OATT on file with FERC. EEI operates its own balancing authority area and its own transmission facilities in southern Illinois. The EEI transmission system is directly connected to MISO, the Tennessee Valley Authority, and Louisville Gas and Electric Company. EEI s generating units are dispatched separately from those of UE, Genco and AERG.

On August 2, 2010, Ameren announced the formation of ATX. ATX intends to build projects initially within Illinois and Missouri, with the potential for expanding to other areas in the future. ATX s initial investments are expected to be the Grand Rivers projects, the first of which involves building a 345 kilovolt line across the state of Illinois, from the Missouri border to the Indiana border. The investment could total more than $1.3 billion through 2021, with a potential investment of $265 million from 2011 to 2015.

The Ameren Companies and EEI are members of SERC. SERC is responsible for the bulk electric power supply system in many states, including all or portions of Missouri, Illinois, Arkansas, Kentucky, Tennessee, North Carolina, South Carolina, Georgia, Mississippi, Alabama, Louisiana, Virginia, Florida, Oklahoma, Iowa, and Texas. As a result of the Energy Policy Act of 2005, owners and operators of the bulk electric power system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and its regional entities, such as SERC, and enforced by FERC. The Ameren Companies must follow these standards, which are in place to require that proper functions are performed to ensure the reliability of the bulk electric power system.

See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for additional information.

Ameren Missouri (UE)

UE s electric supply is obtained primarily from its own generation. Factors that could cause UE to purchase power

include, among other things, absence of sufficient owned generation, plant outages, the fulfillment of renewable energy requirements, the failure of suppliers to meet their power supply obligations, extreme weather conditions, and the availability of power at a cost lower than the cost of generating it.

UE continues to evaluate its longer-term needs for new baseload and peaking electric generation capacity. UE s integrated resource plan filed with the MoPSC in February 2011 included the expectation that new baseload generation capacity would be required between 2020 and 2030. Because of the significant time required to plan, acquire permits for, and build a baseload power plant, UE continues to study future plant alternatives, as well as energy efficiency programs that could help defer new plant construction. To prepare for the long-term need for baseload capacity, and to prepare for potentially more stringent environmental regulation of coal-fired power plants, which could lead to the retirement of current baseload assets, UE is taking steps to preserve options to meet future demand. These steps include seeking improvements in regulatory treatment of energy efficiency investments, evaluating potential sites for natural gas-fired generation, and pursuing an ESP for an additional unit at its existing nuclear plant site, subject to passage of state legislation that would ensure rate recovery of the ESP costs once the ESP has been approved by the NRC. In December 2010 and January 2011, the Missouri Energy Partnership Act was separately introduced in both the Missouri Senate and House of Representatives. The purpose of this legislation is to maintain an option for nuclear power in the state of Missouri, recover the costs of the ESP for a period up to 20 years, and provide appropriate consumer protections. This legislation remains pending as of the date of this report.

See also Outlook in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 2 Rate and Regulatory Matters and Note 15 Commitments and Contingencies under Part II, Item 8, of this report.

Ameren Illinois (AIC)

AIC is required to obtain from market sources all electric supply requirements for customers, except those customers in markets declared competitive, who do not purchase electric supply from third-party suppliers. The power procurement costs incurred by AIC are passed directly to its customers through a cost recovery mechanism.

As part of the 2007 Illinois Electric Settlement Agreement, a new competitive power procurement process led by the IPA was implemented beginning in January 2009. The IPA administers a RFP process that procures AIC s expected supply obligation. Since the start of this process, the ICC has approved the outcomes of multiple electric power procurement RFPs for energy, capacity and renewable energy credits covering different time periods.

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A portion of the electric power supply required for AIC to satisfy its distribution customers requirements is purchased in the RFP process administered by the IPA from Marketing Company on behalf of Genco, AERG and EEI. In addition, as part of the 2007 Illinois Electric Settlement Agreement, AIC entered into financial contracts with Marketing Company (for the benefit of Genco and AERG) to lock in energy prices for 400 to 1,000 megawatts annually of its round-the-clock power requirements during the period June 1, 2008, through December 31, 2012, at the market prices relevant at that time. These financial contracts do not include capacity, are not load-following products, and do not involve the physical delivery of energy.

See Note 2 Rate and Regulatory Matters, Note 14 Related Party Transactions and Note 15 Commitments and Contingencies under Part II, Item 8, of this report for additional information on power procurement in Illinois.

Merchant Generation

Genco and AERG have entered into power supply agreements with Marketing Company whereby Genco and AERG sell, and Marketing Company purchases, all the capacity available from Genco s and AERG s generation fleets and the associated energy. These power supply agreements continue through December 31, 2022, and from year to year thereafter unless either party elects to

terminate the agreement by providing the other party with no less than six months advance written notice. EEI and Marketing Company have entered into a power supply agreement for EEI to sell all of its capacity and energy to Marketing Company. This agreement expires on May 31, 2016. All of Genco s, AERG s and EEI s generating facilities compete for the sale of energy and capacity in the competitive energy markets through Marketing Company. See Note 14 Related Party Transactions under Part II, Item 8, of this report for additional information.

On September 28, 2010, Resources Company announced that it signed a cooperative agreement with the DOE that could lead to repowering a unit at Genco s Meredosia plant. This would create the world s first full-scale, oxy-combustion coal-fired plant designed for permanent CO_2 capture and storage. Ameren and two independent companies will assess the project in phases to validate the project s scope, cost, schedule and commercial viability. If the first phases are successful and the project has received regulatory approval, Ameren and its partners will initiate the construction necessary to repower the plant.

FUEL FOR POWER GENERATION

The following table presents the source of electric generation by fuel type, excluding purchased power, for the years ended December 31, 2010, 2009 and 2008:

	Coal	Nuclear	Natural Gas	Hydroelectric	Oil
Ameren:[(a)]					
2010	**85%**	**12%**	**1%**	**2%**	**(b)%**
2009	83	13	1	3	(b)
2008	85	12	1	2	(b)
Ameren Missouri (UE):					
2010	**77%**	**19%**	**1%**	**3%**	**-%**
2009	75	21	(b)	4	-
2008	77	19	1	3	(b)
Merchant Generation:					
2010	**98%**	**-%**	**2%**	**-%**	**(b)%**
2009	99	-	1	-	(b)
2008	99	-	1	-	(b)
Genco:					
2010	**99%**	**-%**	**1%**	**-%**	**(b)%**
2009	100	-	(b)	-	(b)
2008	99	-	1	-	(b)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Less than 1% of total fuel supply.

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The following table presents the cost of fuels for electric generation for the years ended December 31, 2010, 2009 and 2008:

Cost of Fuels (Dollars per million Btus)	**2010**	**2009**	**2008**
Ameren:			
Coal[a]	**$ 1.848**	$ 1.654	$ 1.572[b]
Nuclear	**0.701**	0.620	0.493
Natural gas[c]	**6.539**	8.685	10.503
Weighted average all fuels[d]	**$ 1.803**	$ 1.591	$ 1.573[b]
Ameren Missouri (UE):			
Coal[a]	**$ 1.675**	$ 1.534	$ 1.426
Nuclear	**0.701**	0.620	0.493
Natural gas[c]	**6.199**	8.544	10.264
Weighted average all fuels[d]	**$ 1.563**	$ 1.386	$ 1.340
Merchant Generation:			
Coal[a]	**$ 2.063**	$ 1.813	$ 1.746[b]
Natural gas[c]	**6.972**	8.796	10.764
Weighted average all fuels[d]	**$ 2.169**	$ 1.934	$ 1.919[b]
Genco:			
Coal[a]	**$ 2.112**	$ 1.869	$ 1.786
Natural gas[c]	**7.881**	13.159	15.857
Weighted average all fuels[d]	**$ 2.206**	$ 1.957	$ 1.896

(a) The fuel cost for coal represents the cost of coal, costs for transportation, which includes railroad diesel fuel additives, and cost of emission allowances.
(b) Excludes impact of the Genco coal supply contract settlement under which Genco received a lump-sum payment of $60 million in July 2008 from a coal mine owner. See Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report.
(c) The fuel cost for natural gas represents the cost of natural gas and firm and variable costs for transportation, storage, balancing, and fuel losses for delivery to the plant. In addition, the fixed costs for firm transportation and firm storage capacity are included in the calculation of fuel cost for the generating facilities.
(d) Represents all costs for fuels used in our electric generating facilities, to the extent applicable, including coal, nuclear, natural gas, oil, propane, tire chips, paint products, and handling. Oil, paint, propane, and tire chips are not individually listed in this table because their use is minimal.

Coal

Ameren, UE and Genco have agreements in place to purchase a portion of their coal needs and to transport it to electric generating facilities through 2019. Ameren, UE and Genco expect to enter into additional contracts to purchase coal from time to time. Coal supply agreements typically have an initial term of up to five years, with about 20% of the contracts expiring annually. UE has an ongoing need for coal to serve its native load customers and pursues a price hedging strategy consistent with this requirement. Merchant Generation s forward coal requirements are dependent on the volume of power sales that have been contracted. As such, Merchant Generation strives to achieve increased margin certainty by aligning its fuel purchases with its power sales. Ameren burned 39 million tons (UE 22 million, Genco 13 million) of coal in 2010. See Part II, Item 7A Quantitative and Qualitative Disclosures About Market Risk of this report for additional information about coal supply contracts.

About 97% of Ameren s coal (UE 97%, Genco 97%) is purchased from the Powder River Basin in Wyoming. The remaining coal is typically purchased from the Illinois Basin. Ameren, UE and Genco have a goal to maintain coal inventory consistent with their risk management policies. Inventory may be adjusted because of changes in burn or uncertainties of supply due to

potential work stoppages, delays in coal deliveries, equipment breakdowns, and other factors. In the past, deliveries from the Powder River Basin have occasionally been restricted because of rail maintenance, weather, and derailments. As of December 31, 2010, coal inventories for Ameren, UE and Genco were at targeted levels. However, in 2011 Merchant Generation is targeting a reduction in its coal inventory, relative to previous levels. Disruptions in coal deliveries could cause Ameren, UE and Genco to pursue a strategy that could include reducing sales of power during low-margin periods, buying higher-cost fuels to generate required electricity, and purchasing power from other sources.

Nuclear

The steps in the process to provide nuclear fuel generally involve the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride gas, the enrichment of that gas, and the fabrication of the enriched uranium hexafluoride gas into usable fuel assemblies. UE has entered into uranium, uranium conversion, enrichment, and fabrication contracts to procure the fuel supply for its Callaway nuclear plant.

Fuel assemblies for the 2011 fall refueling at UE s Callaway nuclear plant are scheduled for manufacture and

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delivery to the plant during May to July 2011. UE also has agreements or inventories to price-hedge approximately 98%, 84%, and 71% of Callaway s 2011, 2013, and 2014 refueling requirements, respectively. UE has uranium (concentrate and hexafluoride) inventories and supply contracts sufficient to meet all of its uranium and conversion requirements through at least 2014. UE has enriched uranium inventories and enrichment supply contracts sufficient to satisfy enrichment requirements through 2013. Fuel fabrication services are under contract through 2014. UE expects to enter into additional contracts to purchase nuclear fuel. As a member of Fuelco, UE can join with other member companies to increase its purchasing power, enhance diversification and pursue opportunities for volume discounts. The Callaway nuclear plant normally requires refueling at 18-month intervals. The last refueling was completed in May 2010. There is no refueling scheduled for 2012 and 2015. The nuclear fuel markets are competitive, and prices can be volatile; however, we do not anticipate any significant problems in meeting our future supply requirements.

Natural Gas Supply

To maintain gas deliveries to gas-fired generating units throughout the year, especially during the summer peak demand, Ameren s portfolio of natural gas supply resources includes firm transportation capacity and firm no-notice storage capacity leased from interstate pipelines. UE and Genco primarily use the interstate pipeline systems of Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Natural Gas Pipeline Company of America, and Mississippi River Transmission Corporation to transport natural gas to generating units. In addition to physical transactions, Ameren uses financial instruments, including some in the NYMEX futures market and some in the OTC financial markets, to hedge the price paid for natural gas.

UE s and Genco s natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to their generating units. This is accomplished by optimizing transportation and storage options and minimizing cost and price risk through various supply and price-hedging agreements that allow access to multiple gas pools, supply basins, and storage services. As of December 31, 2010, UE had price-hedged about 30% and Genco had price-hedged 84% of its expected natural gas supply requirements for generation in 2011.

Renewable Energy

Illinois and Missouri have enacted laws requiring electric utilities to include renewable energy resources in their portfolios. Illinois requires renewable energy resources to equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers as of June 1, 2008, increasing to 15% by June 1, 2015, and to 25% by June 1, 2025. AIC has procured renewable energy credits under the IPA-administered procurement process to

meet the renewable energy portfolio requirement through May 2011. In December 2010, AIC entered into a 20-year power purchase agreement with renewable energy suppliers and will begin purchasing power under the agreement starting in June 2012, to help supplement these requirements. Approximately 50% of the 2012 renewable energy requirement will be met through this agreement. See Note 2 Rate and Regulatory Matters under Part II, Item 8, for additional information about the Illinois power procurement process.

In Missouri, utilities are required to purchase or generate from renewable energy sources electricity equaling at least 2% of native load sales, with that percentage increasing to at least 15% by 2021, subject to a 1% limit on customer rate impacts. At least 2% of each renewable energy portfolio requirement must be derived from solar energy. UE expects to satisfy the nonsolar requirement through 2017 with existing renewable generation in its current fleet along with a 15-year, 102-MW power purchase agreement with a wind farm operator in Iowa that became effective in 2009 and the landfill gas project discussed below. Currently, UE expects to meet the solar energy requirement through the purchase of solar-generated renewable energy credits.

In September 2009, UE announced an agreement with a landfill owner to install CTs at a landfill site in St. Louis County, Missouri, which is expected to generate approximately 15MW of electricity by burning methane gas collected from the landfill. Site preparation for the CTs began in 2010 and construction will begin in 2011. The CTs are expected to begin generating power in 2012. UE signed a 20-year supply agreement with the landfill owner to purchase methane gas.

Energy Efficiency

Ameren s regulated utilities have implemented energy efficiency programs to educate and help their customers become more efficient users of energy. A law in Missouri allows electric utilities to recover costs related to MoPSC-approved energy efficiency programs. The law could, among other things, allow UE to earn a return on its energy efficiency programs equivalent to the return UE could earn with supply-side capital investments, such as new power plants. UE introduced multiple energy efficiency programs in 2009 and 2010. UE has set up a website at www.uefficiency.com in order to provide more information to its customers regarding energy efficiency.

AIC is participating in the Illinois Clean Energy Community Foundation, a program that supports energy efficiency, promotes renewable energy, and provides educational opportunities. In 2008, the ICC issued orders approving AIC s electric energy efficiency plan as well as cost recovery mechanisms by which program costs are being recovered from customers. AIC has set up a website at www.actonenergy.com in order to provide more information to its customers regarding energy efficiency.

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NATURAL GAS SUPPLY FOR DISTRIBUTION

UE and AIC are responsible for the purchase and delivery of natural gas to their gas utility customers. UE and AIC develop and manage a portfolio of gas supply resources. These include firm gas supply under term agreements with producers, interstate and intrastate firm transportation capacity, firm storage capacity leased from interstate pipelines, and on-system storage facilities to maintain gas deliveries to customers throughout the year and especially during peak demand. UE and AIC primarily use the Panhandle Eastern Pipe Line Company, the Trunkline Gas Company, the Natural Gas Pipeline Company of America, the Mississippi River Transmission Corporation, the Northern Border Pipeline Company and the Texas Eastern Transmission Corporation interstate pipeline systems to transport natural gas to their systems. In addition to physical transactions, financial instruments, including those entered into in the NYMEX futures market and in the OTC financial markets, are used to hedge the price paid for natural gas. See Part II, Item 7A Quantitative and Qualitative Disclosures About Market Risk of this report for additional information about natural gas supply contracts. Prudently incurred natural gas purchase costs are passed on to customers of UE and AIC in Missouri and Illinois under PGA clauses, subject to prudency reviews by the MoPSC and the ICC. As of December 31, 2010, UE had price-hedged 90%, and AIC had price-hedged 89%, of its expected natural gas supply requirements for distribution in 2011.

For additional information on our fuel and purchased power supply, see Results of Operations, Liquidity and Capital Resources and Effects of Inflation and Changing Prices in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report. Also see Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, of this report, Note 1 Summary of Significant Accounting Policies, Note 7 Derivative Financial Instruments, Note 10 Callaway Nuclear Plant, Note 14 Related Party Transactions, and Note 15 Commitments and Contingencies under Part II, Item 8.

INDUSTRY ISSUES

We are facing issues common to the electric and natural gas utility industry and the merchant electric generation industry. These issues include:

- continually developing and complex environmental laws, regulations and issues, including air and water-quality standards, mercury regulations, and increasingly likely greenhouse gas limitations and ash management requirements;
- political and regulatory resistance to higher rates, especially in a difficult economic environment;
- the potential for changes in laws, regulation, and policies at the state and federal level, including those resulting from election cycles;
- access to, and uncertainty in, the capital and credit markets;
- the potential for more intense competition in generation, supply and distribution, including new technologies;
- pressure on customer growth and usage in light of current economic conditions and energy efficiency initiatives;
- the potential for reregulation in some states, including Illinois, which could cause electric distribution companies to build or acquire generation facilities and to purchase less power from electric generating companies such as Genco, AERG and EEI;
- changes in the structure of the industry as a result of changes in federal and state laws, including the formation of merchant generating and independent transmission entities and RTOs;
- increases, decreases and volatility in power prices due to the balance of supply and demand and marginal fuel costs;
- the availability of fuel and increases or decreases in fuel prices;
- the availability of qualified labor and material, and rising costs;
- regulatory lag;
- decreased free cash flows due to rising infrastructure investments and the regulatory framework;
- public concern about the siting of new facilities;
- aging infrastructure and the need to construct new power generation, transmission and distribution facilities;
- proposals for programs to encourage or mandate energy efficiency and renewable sources of power;
- public concerns about nuclear plant operation and decommissioning and the disposal of nuclear waste; and
- consolidation of electric and natural gas companies.

We are monitoring these issues. Except as otherwise noted in this report, we are unable to predict what impact, if any, these issues will have on our results of operations, financial position, or liquidity. For additional information, see Risk Factors under Part I, Item 1A, and Outlook and Regulatory Matters in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 2 Rate and Regulatory Matters, and Note 15 Commitments and Contingencies under Part II, Item 8, of this report.

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OPERATING STATISTICS

The following tables present key electric and natural gas operating statistics for Ameren for the past three years:

Electric Operating Statistics Year Ended December 31,	**2010**	2009	2008
Electric Sales kilowatthours (in millions):			
Ameren Missouri:			
Residential	**14,640**	13,413	13,904
Commercial	**15,002**	14,510	14,690
Industrial	**8,656**	7,037	9,256
Other	**1,429**	1,655	785
Native load subtotal	**39,727**	36,615	38,635
Off-system sales	**8,496**	12,447	10,457
Subtotal	**48,223**	49,062	49,092
Ameren Illinois:			
Residential			
Power supply and delivery service	**12,341**	11,089	11,667
Commercial			
Power supply and delivery service	**4,419**	5,235	6,095
Delivery service only	**8,051**	6,797	6,147
Industrial			
Power supply and delivery service	**1,389**	514	1,442
Delivery service only	**11,147**	10,712	11,300
Other	**545**	546	555
Native load subtotal	**37,892**	34,893	37,206
Merchant Generation:			
Nonaffiliate energy sales	**30,788**	25,673	26,395
Affiliate native energy sales	**949**	3,529	6,055
Subtotal	**31,737**	29,202	32,450
Eliminate affiliate sales	**(949)**	(3,529)	(6,055)
Eliminate Ameren Illinois/Merchant Generation common customers	**(5,016)**	(5,566)	(4,939)
Ameren total	**111,887**	104,062	107,754
Electric Operating Revenues (in millions):			
Ameren Missouri:			
Residential	**$ 1,193**	$ 982	$ 948
Commercial	**1,004**	881	838
Industrial	**399**	314	372
Other	**147**	122	108
Native load subtotal	**$ 2,743**	$ 2,299	$ 2,266
Off-system sales	**287**	401	490
Subtotal	**$ 3,030**	$ 2,700	$ 2,756
Ameren Illinois:			
Residential			
Power supply and delivery service	**$ 1,270**	$ 1,094	$ 1,112
Commercial			
Power supply and delivery service	**425**	521	616
Delivery service only	**143**	103	77
Industrial			
Power supply and delivery service	**66**	22	102
Delivery service only	**38**	36	30
Other	**119**	189	305
Native load subtotal	**$ 2,061**	$ 1,965	$ 2,242
Merchant Generation:			
Nonaffiliate energy sales	**$ 1,442**	$ 1,340	$ 1,389
Affiliate native energy sales	**231**	385	441
Other	**20**	(15)	106
Subtotal	**$ 1,693**	$ 1,710	$ 1,936
Eliminate affiliate revenues	**(263)**	(435)	(547)
Ameren total	**$ 6,521**	$ 5,940	$ 6,387

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Electric Operating Statistics Year Ended December 31,	2010	2009	2008
Electric Generation megawatthours (in millions):			
Ameren Missouri	**48.1**	48.7	49.3
Merchant Generation:			
Genco	**22.0**	20.5	24.6
AERG	**7.5**	6.8	6.7
Medina Valley	**0.1**	0.2	0.2
Subtotal	**29.6**	27.5	31.5
Ameren total	**77.7**	76.2	80.8
Price per ton of delivered coal (average)	**$ 32.91**	$ 29.85	$ 26.90[a]
Source of energy supply:			
Coal	**65.7%**	67.0%	70.1%
Nuclear	**8.9**	10.8	9.5
Hydroelectric	**1.6**	2.0	1.8
Gas	**1.0**	0.6	0.8
Purchased Wind	**0.3**	0.1	-
Purchased Other	**22.5**	19.5	17.8
	100.0%	100.0%	100.0%

Gas Operating Statistics Year Ended December 31,	2010	2009	2008
Gas Sales (millions of Dth)			
Ameren Missouri:			
Residential	**7**	7	8
Commercial	**4**	4	4
Industrial	**1**	1	1
Subtotal	**12**	12	13
Ameren Illinois:			
Residential	**60**	60	65
Commercial	**23**	26	28
Industrial	**7**	7	11
Subtotal	**90**	93	104
Other:			
Industrial	**1**	3	4
Subtotal	**1**	3	4
Eliminate affiliate sales	**-**	-	(1)
Ameren total	**103**	108	120
Natural Gas Operating Revenues (in millions)			
Ameren Missouri:			
Residential	**$ 100**	$ 106	$ 121
Commercial	**43**	47	54
Industrial	**10**	10	12
Other	**13**	7	14
Subtotal	**$ 166**	$ 170	$ 201
Ameren Illinois:			
Residential	**$ 649**	$ 646	$ 819
Commercial	**223**	259	338
Industrial	**44**	38	119
Other	**37**	72	(11)
Subtotal	**$ 953**	$ 1,015	$ 1,265
Other:			
Industrial	**$ 4**	$ 15	$ 26
Subtotal	**$ 4**	$ 15	$ 26
Eliminate affiliate revenues	**(6)**	(5)	(10)
Ameren total	**$ 1,117**	$ 1,195	$ 1,482

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Gas Operating Statistics Year Ended December 31,	2010	2009	2008
Peak day throughput (thousands of Dth):			
UE	**167**	163	158
AIC	**1,227**	1,353	1,280
Total peak day throughput	**1,394**	1,516	1,438

(a) Includes impact of the Genco coal settlement under which Genco received a lump-sum payment of $60 million in July 2008 from a coal mine owner. See Note 1 Summary of Significant Account Policies under Part II, Item 8, of this report.

AVAILABLE INFORMATION

The Ameren Companies make available free of charge through Ameren s website (www.ameren.com) their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Ameren s eXtensible Business Reporting Language (XBRL) documents, and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Exchange Act as soon as reasonably possible after such reports are electronically filed with, or furnished to, the SEC. These documents are also available through an Internet website maintained by the SEC (www.sec.gov). Ameren also uses its website (www.ameren.com) as a channel of distribution of material information relating to the Ameren Companies. Financial and other material information regarding the Ameren Companies is routinely posted and accessible at Ameren s website.

The Ameren Companies also make available free of charge through Ameren s website (www.ameren.com) the charters of Ameren s board of directors audit and risk committee, human resources committee, nominating and corporate governance committee, finance committee, nuclear oversight and environmental committee, and public policy committee; the corporate governance guidelines; a policy regarding communications to the board of directors; a policy and procedures with respect to related-person transactions; a code of ethics for principal executive and senior financial officers; a code of business conduct applicable to all directors, officers and employees; and a director nomination policy that applies to the Ameren Companies. The information on Ameren s website, or any other website referenced in this report, is not incorporated by reference into this report.

ITEM 1A. RISK FACTORS.

Investors should review carefully the following risk factors and the other information contained in this report. The risks that the Ameren Companies face are not limited to those in this section. There may be additional risks and uncertainties (either currently unknown or not currently believed to be material) that could adversely affect the results of operations, financial position, and liquidity of the Ameren Companies. See Forward-looking Statements above and Outlook in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report.

We are subject to extensive regulation of our businesses, which could adversely affect our results of operations, financial position, and liquidity.

We are subject to, or affected by, extensive federal and state regulation. This extensive regulatory framework, some but not all of which is more specifically identified in the following risk factors, regulates, among other matters, the electric and natural gas industries; rate and cost structure of utilities; operation of nuclear power facilities; construction and operation of generation, transmission and distribution facilities; acquisition, disposal, depreciation and amortization of assets and facilities; transmission reliability; and present or prospective wholesale and retail competition. We must address in our business planning and management of operations the effects of existing and proposed laws and regulations and potential changes in the regulatory framework, including initiatives by federal and state legislatures, RTOs, utility regulators, and taxing authorities. Significant changes in the nature of the regulation of our businesses could require changes to our business planning and management of our businesses and could adversely affect our results of operations, financial position, and liquidity. Failure to obtain adequate rates or regulatory approvals in a timely manner, failure to obtain necessary licenses or permits from regulatory authorities, new or changed laws, regulations, standards, interpretations, or other legal requirements, or increased compliance costs could adversely impact our results of operations, financial position, and liquidity.

The electric and natural gas rates that UE and AIC are allowed to charge are determined through regulatory proceedings, which are subject to appeal, and are subject to legislative actions, which are largely outside of their control. Any events that prevent UE or AIC from recovering their respective costs or from earning appropriate returns on their investments could have a material adverse effect on results of operations, financial position, and liquidity.

The rates that UE and AIC are allowed to charge for their utility services significantly influence the results of operations, financial position, and liquidity of these companies and Ameren. The electric and natural gas utility industry is highly regulated. The utility rates charged to UE and AIC customers are determined, in large part, by governmental entities, including the MoPSC, the ICC, and FERC. Decisions by these entities are influenced by many factors, including the cost of providing service, the

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prudency of expenditures, the quality of service, regulatory staff knowledge and experience, economic conditions, public policy, and social and political views. Decisions made by these governmental entities regarding rates are largely outside of UE s and AIC s control. Regulatory lag involved in filing and getting new rates approved could have a material adverse effect on our results of operations, financial position, and liquidity. Rate orders are also subject to appeal and stay requests, which create additional uncertainty as to the rates UE and AIC will ultimately be allowed to charge for their services.

UE and AIC electric and natural gas utility rates are typically established in regulatory proceedings that take up to 11 months to complete. Rates established in those proceedings for UE are primarily based on historical costs and revenues. Rates established in those proceedings for AIC may be based on historical or estimated future costs and revenues. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rates include an allowed return on investments by the regulators. Although rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all the costs of UE and AIC to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs or an adequate return on those investments.

During periods of rising costs and investments or declining retail usage, UE and AIC may not be able to earn the allowed return established by their regulators. This could result in deferral or elimination of planned capital investments. As a result, UE and AIC expect to file rate cases frequently. A period of increasing rates for our customers, especially during weak economic times, could result in additional regulatory and legislative actions, as well as competitive and political pressures, which could have a material adverse effect on our results of operations, financial position, and liquidity.

We are subject to various environmental laws and regulations that require significant capital expenditures or could result in closure of facilities, could increase our operating costs, and could adversely influence or limit our results of operations, financial position, and liquidity, or expose us to fines and liabilities.

We are subject to various environmental laws and regulations enforced 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, natural gas storage facilities, and natural gas transmission and distribution facilities, our activities involve compliance with diverse environmental laws and regulations. These laws and regulations address emissions, impacts to air, land and water, noise, protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archeological and historical resources), and

chemical and waste handling. Complex and lengthy processes are required 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 release prevention plans and emergency response procedures.

In addition to existing laws and regulations governing our facilities, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren, UE and Genco that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; revised ambient air quality standards for SO_2 and NO_x emissions that increase the stringency of the existing ozone ambient air quality standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is also expected to propose new regulations under the Clean Water Act, which could require significant capital expenditures such as new water intake structures or cooling towers at our power plants; NSPS and emission guidelines for greenhouse gas emissions applicable to new and existing electric generating units; and a MACT standard for the control of hazardous air pollutants such as mercury and acid gases from power plants. Such new regulations may be challenged with lawsuits, so the timing of their ultimate implementation is uncertain. Although many of the details of these future regulations are unknown, the combined effect of the new and proposed environmental regulations may result in significant capital expenditures and/or increased operating costs over the next five to eight years for Ameren, UE and Genco. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. As a result, these regulations could require us to close or to significantly alter the operation of our generating facilities, which could have an adverse effect on our results of operations, financial position, and liquidity. Failure to comply with environmental laws and regulations may also result in the imposition of fines, penalties, and injunctive measures.

We are also subject to liability under environmental laws for remediating environmental contamination of property now or formerly owned by us or by our predecessors, as well as property contaminated by hazardous substances that we generated. Such sites include MGP sites and third-party sites, such as landfills. Additionally, private individuals may seek to enforce environmental laws and regulations against us and could allege injury from exposure to hazardous materials.

Ameren also may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations. The EPA is engaged in an enforcement initiative targeted at coal-fired power plants in the United States to determine whether coal-fired power plants failed to comply

with the requirements of the NSR and NSPS provisions under the Clean Air Act when the plants implemented modifications. Failure to comply with the NSR and NSPS provisions under the Clean Air Act can result in increased capital expenditures for the installation of control technology, increased operations and maintenance expenses, and fines or penalties. Ameren and Genco have received requests for information from the EPA pursuant to Section 114(a) of the Clean Air Act. In January 2010, UE received a Notice of Violation from the EPA alleging violations of the Clean Air Act s NSR and Title V programs. In the Notice of Violation, the EPA contends that various projects at UE s Labadie, Meramec, Rush Island, and Sioux coal-fired power plant facilities, dating back to the mid-1990s, triggered NSR requirements. In October 2010, the EPA supplemented and amended the Notice of Violation to include additional projects at UE s coal-fired power plant facilities. The amended Notice of Violation followed a series of information requests under Section 114(a). In January 2011, the EPA filed a complaint against UE in the United States District Court for the Eastern District of Missouri. The EPA s complaint alleges that in performing projects at its Rush Island coal-fired generating facility, UE violated provisions of the Clean Air Act and Missouri law. At present, the complaint does not include UE s other coal-fired facilities. Litigation of this matter could take many years to resolve. An outcome in this matter adverse to UE could require substantial capital expenditures and the payment of substantial penalties, neither of which can be determined at this time. Such expenditures could affect unit retirement and replacement decisions and our results of operations, financial position, and liquidity if such costs are not recovered through regulated rates.

Ameren, UE and Genco have incurred and expect to incur significant costs related to environmental compliance and site remediation. New environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation could result in a significant increase in capital expenditures and operating costs, decreased revenues, increased financing requirements, penalties, or closure of facilities for Ameren, UE and Genco. Although costs incurred by UE would be eligible for recovery in rates over time, subject to MoPSC approval in a rate proceeding, there is no similar cost recovery mechanism for Genco or for Ameren s Merchant Generation business segment. We are unable to predict the ultimate impact of these matters on our results of operations, financial position, and liquidity.

Future limits on greenhouse gas emissions would likely require Ameren, UE and Genco to incur significant increases in capital expenditures and operating costs, which, if excessive, could result in the closures of coal-fired generating plants, impairment of assets, or otherwise materially adversely affect our results of operations, financial position, and liquidity.

Initiatives to limit greenhouse gas emissions and to address climate change have been subject to consideration in the U.S. Congress. In the past two years, legislation has been passed in the U.S. House of Representatives and

proposed in the Senate to reduce greenhouse gas emissions from designated sources, including coal-fired electric generation units. Many of these proposals have included economy-wide cap-and-trade programs. The reduction of greenhouse gas emissions has been identified as a high priority by President Obama s administration.

Potential impacts from climate change legislation could vary, depending upon proposed CO_2 emission limits, the timing of implementation of those limits, the method of distributing any allowances, the degree to which offsets are allowed and available, and provisions for cost-containment measures, such as a safety valve provision that provides a maximum price for emission allowances. Our emissions of greenhouse gases vary among our generating facilities, but coal-fired power plants are significant sources of CO_2. Ameren s analysis shows that if most versions of the recently proposed climate change bills were enacted into law, household costs and rates for electricity could rise significantly. The burden could fall particularly hard on electricity consumers and upon the economy in the Midwest because of the region s reliance on electricity generated by coal-fired power plants. Natural gas emits per kilowatthour about half as much CO_2 as coal emits when burned to produce electricity. Therefore, climate change regulation could cause the conversion of coal-fired power plants to natural gas, or the construction of new natural gas plants to replace coal-fired power plants. As a result, economy-wide shifts to natural gas as a fuel source for electricity generation also could affect the cost of heating for our utility customers and many industrial processes that use natural gas. Higher costs for energy could contribute to reduced demand for electricity and natural gas.

In December 2009, the EPA issued its endangerment finding determining that greenhouse gas emissions, including CO_2, endanger human health and welfare and that emissions of greenhouse gases from motor vehicles contribute to that endangerment. In March 2010, the EPA issued a determination that greenhouse gas emissions from stationary sources, such as power plants, would be subject to regulation under the Clean Air Act in 2011. As a result of these actions, we will be required to consider the emissions of greenhouse gas in any air permit application submitted by us or pending after January 1, 2011.

Recognizing the difficulties presented by regulating at once virtually all emitters of greenhouse gases, the EPA finalized in May 2010 regulations known as the Tailoring Rule, that would establish new higher thresholds for regulating greenhouse gas emissions from stationary sources, such as power plants. The Tailoring Rule became effective in January 2011. The rule requires any source that already has an operating permit to have greenhouse-gas-specific provisions added to their permits upon renewal. Currently, all Ameren power plants have operating permits that, when renewed, may be modified to address greenhouse gas emissions. The Tailoring Rule also provides that if projects performed at major sources result in an increase in emissions of greenhouse gases of at least 75,000 tons per year, measured as CO_2 equivalents, such

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projects could trigger permitting requirements under the NSR/Prevention of Significant Deterioration program and the application of best available control technology, if any, to control greenhouse gas emissions. New major sources also would be required to obtain such a permit and to install the best available control technology if their greenhouse gas emissions exceed the applicable emissions threshold. Separately, in December 2010, the EPA announced it would establish NSPS for greenhouse gas emissions at new and existing fossil-fuel fired power plants. In the announcement, the EPA said it will propose standards for power plants in July 2011 and issue final standards in May 2012. It is uncertain whether reductions to greenhouse gas emissions would be required at our power plants as a result of any of the EPA s new and future rules. Legal challenges to the EPA s greenhouse gas rules have been filed and more challenges are expected. Any federal climate change legislation that is enacted may preempt the EPA s regulation of greenhouse gas emissions, including the Tailoring Rule, particularly as it relates to power plant greenhouse gas emissions. The extent to which the Tailoring Rule could have a material impact on our generating facilities depends upon how state agencies apply the EPA s guidelines as to what constitutes the best available control technology for greenhouse gas emissions from power plants, whether physical changes or changes in operations subject to the rule occur at our power plants, and whether federal legislation that preempts the rule is passed.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would likely result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Moreover, to the extent UE requests recovery of these costs through rates, its regulators might deny some or all of, or defer timely recovery of, these costs. Excessive costs to comply with future legislation or regulations might force Ameren, UE and Genco as well as other similarly situated electric power generators to close some coal-fired facilities and could lead to possible impairment of assets and reduced revenues. As a result, mandatory limits could have a material adverse impact on Ameren s, UE s, and Genco s results of operations, financial position, and liquidity.

The construction of, and capital improvements to, Ameren s, UE s and AIC s electric and gas utility infrastructure as well as to Ameren s and Genco s merchant generation facilities involve substantial risks. These risks include escalating costs, unsatisfactory performance by the projects when completed, the inability to complete projects as scheduled, cost disallowances by regulators and the inability to earn a reasonable return on invested capital, any of which could result in higher costs and the closure of facilities.

Over the next five years, the Ameren Companies will incur significant capital expenditures to comply with existing and known environmental regulations and to make investments in their electric and gas natural utility infrastructure and their merchant generation facilities. The

Ameren Companies estimate that they will incur up to $8.2 billion (UE up to $4.1 billion; AIC up to $2.4 billion; Genco up to $1.0 billion; other up to $700 million) of capital expenditures during the period 2011 through 2015. These expenses include construction expenditures, capitalized interest or allowance for funds used during construction, and compliance with environmental standards. Construction costs as well as the cost of capital have escalated in recent years. They are expected to stay at current levels or to escalate further.

Investments in Ameren s regulated operations are expected to be recoverable from ratepayers, but are subject to prudency reviews and regulatory lag. The recoverability of amounts expended in merchant generation operations will depend upon market prices for capacity and energy.

The ability of the Ameren Companies to complete facilities under construction successfully, and to complete future projects within established estimates, is contingent upon many variables and subject to substantial risks. These variables include, but are not limited to, project management expertise and escalating costs for materials, labor, and environmental compliance. Delays in obtaining permits, shortages in materials and qualified labor, suppliers and contractors who do not perform as required under their contracts, changes in the scope and timing of projects, the inability to raise capital on favorable terms, or other events beyond our control that could occur may materially affect the schedule, cost and performance of these projects. With respect to capital spent for pollution control equipment, there is a risk that electric generating plants will not be permitted to continue to operate if pollution control equipment is not installed by prescribed deadlines or does not perform as expected. Should any such construction efforts be unsuccessful, the Ameren Companies could be subject to additional costs and to the loss of their investment in the project or facility. The Ameren Companies may also be required to purchase electricity for their customers until the projects are completed. All of these risks may have a material adverse effect on the Ameren Companies results of operations, financial position, and liquidity.

Our counterparties may not meet their obligations to us.

We are exposed to the risk that counterparties to various arrangements who owe us money, credit, energy, coal, or other commodities or services will not be able to perform their obligations or, with respect to our credit facilities, will fail to honor their commitments. Should the counterparties to commodity arrangements fail to perform, we might be forced to replace or to sell the underlying commitment at then-current market prices. Should the lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements would decrease unless we were able to find replacement lenders to assume the nonperforming lender s commitment. In such an event, we might incur losses, or our results of operations, financial position, and liquidity could otherwise be adversely affected.

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Certain of the Ameren Companies have obligations to other Ameren Companies or other Ameren subsidiaries as a result of transactions involving energy, coal, other commodities and services, and as a result of hedging transactions. If one Ameren entity failed to perform under any of these arrangements, other Ameren entities might incur losses. Their results of operations, financial position, and liquidity could be adversely affected, resulting in the nondefaulting Ameren entity being unable to meet its obligations, including to unrelated third parties.

Increasing costs associated with our defined benefit retirement and postretirement plans, health care plans, and other employee benefits could materially adversely affect our results of operations, financial position, and liquidity.

We offer defined benefit retirement and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates, and other actuarial matters have a significant impact on our earnings and funding requirements. Ameren expects to fund its pension plans at a level equal to the greater of the pension expense or the legally required minimum contribution. Considering Ameren s assumptions at December 31, 2010, its investment performance in 2010, and its pension funding policy, Ameren expects to make annual contributions of $75 million to $110 million in each of the next five years, with aggregate estimated contributions of $470 million. We expect UE s, AIC s, and Genco s portion of the future funding requirements to be 63%, 28%, and 9%, respectively. These amounts are estimates. They may change with actual investment performance, changes in interest rates, changes in our assumptions, any pertinent changes in government regulations, and any voluntary contributions.

In addition to the costs of our retirement plans, the costs of providing health care benefits to our employees and retirees have increased in recent years. We believe that our employee benefit costs, including costs of health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements associated with our defined benefit retirement plans, health care plans, and other employee benefits could increase our financing needs and otherwise materially adversely affect our results of operations, financial position, and liquidity.

Our electric generating, transmission and distribution facilities are subject to operational risks that could materially adversely affect our results of operations, financial position, and liquidity.

The Ameren Companies financial performance depends on the successful operation of electric generating, transmission, and distribution facilities. Operation of electric generating, transmission, and distribution facilities involves many risks, including:

- facility shutdowns due to operator error or a failure of equipment or processes;
- longer-than-anticipated maintenance outages;
- older generating equipment may require significant expenditures to keep it operating at peak efficiency;
- disruptions in the delivery of fuel or lack of adequate inventories;
- lack of water for cooling plant operations;
- labor disputes;
- inability to comply with regulatory or permit requirements, including those relating to environmental contamination;
- disruptions in the delivery of electricity, including impacts on us or our customers;
- handling and storage of fossil-fuel combustion byproducts, such as coal ash;
- unusual or adverse weather conditions, including severe storms, droughts, and floods;
- a workplace accident that might result in injury or loss of life, extensive property damage, or environmental damage;
- information security risk, such as a breach of systems where sensitive utility customer data and account information are stored;
- catastrophic events such as fires, explosions, pandemic health events, or other similar occurrences;
- limitations on amounts of insurance available to cover losses that might arise in connection with operating our electric generating, transmission, and distribution facilities; and
- other unanticipated operations and maintenance expenses and liabilities.

We are subject to federal regulatory compliance and proceedings, which increase our risk of regulatory penalties and other sanctions.

The Energy Policy Act of 2005 increased FERC s civil penalty authority for violation of FERC statutes, rules and orders. FERC can now impose penalties of $1 million per violation per day. Under the Energy Policy Act of 2005, the Ameren Companies, as owners and operators of bulk power transmission systems and/or electric generation facilities, are subject to mandatory reliability standards. Compliance with these mandatory reliability standards may subject the Ameren Companies to higher operating costs and may result in increased capital expenditures. If the Ameren Companies were found not to be in compliance with these mandatory reliability standards or other FERC statutes, rules and orders, the Ameren Companies may incur substantial monetary penalties and other sanctions, which could adversely affect their results of operations, financial position, and liquidity.

Our natural gas distribution and storage activities involve numerous risks that may result in accidents and other operating risks and costs that could materially adversely affect our results of operations, financial position, and liquidity.

Inherent in our natural gas distribution and storage activities are a variety of hazards and operating risks, such as leaks, accidental explosions, and mechanical problems, which could cause substantial financial losses. In addition,

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these risks could result in serious injury to employees and nonemployees, loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of distribution lines and storage facilities near populated areas, including residential areas, commercial business centers, industrial sites, and other public gathering places, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could materially adversely affect our results of operations, financial position, and liquidity.

Even though agreements have been reached with the state of Missouri and the FERC, the breach of the upper reservoir of UE s Taum Sauk pumped-storage hydroelectric facility could continue to have a material adverse effect on Ameren s and UE s results of operations, liquidity, and financial condition.

In December 2005, there was a breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility. This resulted in significant flooding in the local area, which damaged a state park. UE settled with FERC and the state of Missouri all issues associated with the December 2005 Taum Sauk incident.

UE had property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance did not cover some lost electric margins and penalties paid to FERC. UE believes that the total cost for cleanup, damage, and liabilities, excluding costs to rebuild the upper reservoir, is approximately $207 million, which is the amount UE paid as of December 31, 2010.

In June 2010, UE sued an insurance company that was providing UE with liability coverage on the date of the Taum Sauk incident. In the litigation, filed in the U.S. District Court for the Eastern District of Missouri, UE claimed the insurance company breached its duty to indemnify UE for the losses experienced from the incident. In January 2011, a federal judge ruled that the parties must first pursue alternative dispute resolution under the terms of their coverage agreement. In February 2011, UE filed an appeal of the January ruling to the U.S. Court of Appeals for the Eighth District, which seeks resolution outside of a dispute resolution process.

Until Ameren s remaining liability insurance claims and the related litigation are resolved, among other things, we are unable to determine the total impact the breach could have on Ameren s and UE s results of operations, financial position, and liquidity beyond those amounts already recognized.

The recoverability of any Taum Sauk facility rebuild costs from customers is subject to the terms and conditions set forth in UE s November 2007 state of

Missouri settlement agreement. In that settlement, UE agreed that it would not attempt to recover from ratepayers costs incurred in the reconstruction, expressly excluding, however, enhancements, costs incurred due to circumstances or conditions that were not at that time reasonably foreseeable and costs that would have been incurred absent the Taum Sauk incident. Certain costs associated with the Taum Sauk facility not recovered from property insurers may be recoverable from UE s electric customers through rates established in rate cases filed subsequent to the in-service date of the rebuilt facility. As of December 31, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $89 million that UE believes qualify for recovery in electric rates under the terms of the November 2007 state of Missouri settlement agreement, and those costs were included in UE s pending electric rate increase request filed in September 2010. The inclusion of such costs in UE s electric rates is subject to review and approval by the MoPSC. Any amounts not recovered in electric rates, or otherwise, could result in charges to earnings, which could be material.

Genco s and AERG s electric generating facilities must compete for the sale of energy and capacity, which exposes them to price risks.

All of Genco s and AERG s generating facilities compete for the sale of energy and capacity in the competitive energy markets.

To the extent that electricity generated by these facilities is not under a fixed-price contract to be sold, the revenues and results of operations of these merchant subsidiaries generally depend on the prices that can be obtained for energy and capacity in Illinois and adjacent markets by Marketing Company.

Market prices for energy and capacity may fluctuate substantially, sometimes over relatively short periods of time, and at other times experience sustained increases or decreases. Demand for electricity and fuel can fluctuate dramatically, creating periods of substantial under- or over-supply. During periods of oversupply, prices might be depressed. Also, at times legislators or regulators with jurisdiction over wholesale and retail energy commodity and transportation rates may impose price limitations, bidding rules, and other mechanisms to address volatility and other issues in these markets.

For power products sold in advance, contract prices are influenced both by market conditions and by the contract terms such as damage provisions, credit support requirements, and the number of available counterparties interested in contracting for the desired forward period. Depending on differences between market factors at the time of contracting versus current conditions, Marketing Company s contract portfolio may have average contract prices greater than or less than current market prices, including at the expiration of the contracts, which could significantly affect Ameren s and Genco s results of operations, financial condition and liquidity.

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Among the factors that could influence such prices (all of which are beyond our control to a significant degree) are:

- current and future delivered market prices for natural gas, fuel oil, and coal, and related transportation costs;
- current and forward prices for the sale of electricity;
- current and future prices for emission allowances that may be required to operate the fossil fuel-fired electric generating facilities in compliance with environmental laws and permits;
- the extent of additional supplies of electric energy from current competitors or new market entrants;
- the regulatory and market structures developed for evolving Midwest energy markets;
- changes enacted by the Illinois legislature, the ICC, the IPA, or other government agencies with respect to power procurement procedures;
- the potential for reregulation of generation in some states;
- future pricing for, and availability of, services on transmission systems, and the effect of RTOs and export energy transmission constraints, which could limit our ability to sell energy in our markets;
- the growth rate in electricity usage as a result of population changes, regional economic conditions, and the implementation of energy-efficiency programs;
- climate conditions in the Midwest market and major natural disasters; and
- environmental laws and regulations.

UE s ownership and operation of a nuclear generating facility creates business, financial, and waste disposal risks.

UE s ownership of the Callaway nuclear plant subjects it to the risks of nuclear generation, which include the following:

- potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- the lack of a permanent waste storage site;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the Callaway nuclear plant or other U.S. nuclear operations;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate;
- public and governmental concerns over the adequacy of security at nuclear power plants;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives (UE s facility operating license for the Callaway nuclear plant expires in 2024);
- limited availability of fuel supply; and
- costly and extended outages for scheduled or unscheduled maintenance and refueling.

The NRC has broad authority under federal law to impose licensing and safety requirements for nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated from time to time by the NRC could necessitate substantial capital expenditures at nuclear plants such as UE s. In addition, if a serious nuclear incident were to occur, it could have a material but indeterminable adverse effect on UE s results of operations, financial position, and liquidity. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit. An incident at a nuclear facility anywhere in the world also could cause the NRC to impose additional conditions or requirements on the industry, which could increase costs and result in additional capital expenditures.

Our energy risk management strategies may not be effective in managing fuel and electricity procurement and pricing risks, which could result in unanticipated liabilities or increased volatility in our earnings and cash flows.

We are exposed to changes in market prices for natural gas, fuel, electricity, emission allowances, and transmission congestion. Prices for natural gas, fuel, electricity, and emission allowances may fluctuate substantially over relatively short periods of time, and at other times exhibit sustained increases or decreases, and expose us to commodity price risk. We use short-term and long-term purchase and sales contracts in addition to derivatives such as forward contracts, futures contracts, options, and swaps to manage these risks. We attempt to manage our risk associated with these activities through enforcement of established risk limits and risk management procedures. We cannot ensure that these strategies will be successful in managing our pricing risk or that they will not result in net liabilities because of future volatility in these markets.

Although we routinely enter into contracts to hedge our exposure to the risks of demand and changes in commodity prices, we do not hedge the entire exposure of our operations from commodity price volatility. Furthermore, our ability to hedge our exposure to commodity price volatility depends on liquid commodity markets. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time. To the extent that unhedged positions exist, fluctuating commodity prices can adversely affect our results of operations, financial position, and liquidity.

Our facilities are considered critical energy infrastructure and may therefore be targets of acts of terrorism.

Like other electric and natural gas utilities and other merchant electric generators, our power generation plants, fuel storage facilities, and transmission and distribution facilities may be targets of terrorist activities that could result in disruption of our ability to produce or distribute some portion of our energy products. Any such disruption could result in a significant decrease in revenues or significant additional costs for repair, which could have a material adverse effect on our results of operations, financial position, and liquidity.

Our businesses are dependent on our ability to access the capital markets successfully. We may not have access to sufficient capital in the amounts and at the times needed.

We use short-term and long-term debt as a significant source of liquidity and funding for capital requirements not satisfied by our operating cash flow, including requirements related to future environmental compliance. As a result of rising costs and increased capital and operations and maintenance expenditures, coupled with regulatory lag, we expect to continue to rely on short-term and long-term debt financing. The inability to raise debt or equity capital on favorable terms, or at all, particularly during times of uncertainty in the capital markets, could negatively affect our ability to maintain and to expand our businesses. Our current credit ratings cause us to believe that we will continue to have access to the capital markets. However, events beyond our control, such as a recession or extreme volatility in global debt or equity capital and credit markets, may create uncertainty that could increase our cost of capital or impair or eliminate our ability to access the debt, equity or credit markets, including our ability to draw on bank credit facilities. Any adverse change in the Ameren Companies credit ratings may reduce access to capital and trigger additional collateral postings and prepayments. Such changes may also increase the cost of borrowing and fuel, power and gas supply, among other things, which could have a material adverse effect on our results of operations, financial position, and liquidity. Certain of the Ameren Companies rely, in part, on Ameren for access to capital. Circumstances that limit Ameren s access to capital, including those relating to its other subsidiaries, could impair its ability to provide those Ameren Companies with needed capital.

Ameren s holding company structure could limit its ability to pay common stock dividends and to service its debt obligations.

Ameren is a holding company; therefore, its primary assets are the common stock of its subsidiaries. As a result, Ameren s ability to pay dividends on its common stock depends on the earnings of its subsidiaries and the ability of its subsidiaries to pay dividends or otherwise transfer funds to Ameren. Similarly, Ameren s ability to service its debt obligations is also dependent upon the earnings of operating subsidiaries and the distribution of those earnings and other payments, including payments of principal and interest under intercompany indebtedness. The payment of dividends to Ameren by its subsidiaries in turn depends on their results of operations and cash flows and other items affecting retained earnings. Ameren s subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any dividends or make any other distributions (except for payments required pursuant to the terms of intercompany borrowing arrangements) to Ameren. Certain of the Ameren Companies financing agreements and articles of incorporation, in addition to certain statutory and regulatory requirements, may impose restrictions on the ability of such Ameren Companies to transfer funds to Ameren in the form of cash dividends, loans or advances.

Failure to retain and attract key officers and other skilled professional and technical employees could have an adverse effect on our operations.

Our businesses depend upon our ability to employ and retain key officers and other skilled professional and technical employees. A significant portion of our work force is nearing retirement, including many employees with specialized skills such as maintaining and servicing our electric and natural gas infrastructure and operating our generating units. Our inability to retain and recruit qualified employees could adversely affect our results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

For information on our principal properties, see the generating facilities table below. See also Liquidity and Capital Resources and Regulatory Matters in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report for any discussion of planned additions, replacements or transfers. See also Note 5 Long-term Debt and Equity Financings, and Note 15 Commitments and Contingencies under Part II, Item 8, of this report.

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The following table shows what our electric generating facilities and capability are anticipated to be at the time of our expected 2011 peak summer electrical demand:

Primary Fuel Source	Plant	Location	Net Kilowatt Capability[(a)]
Ameren Missouri (UE):			
Coal	Labadie	Franklin County, Mo.	2,401,000
	Rush Island	Jefferson County, Mo.	1,222,000
	Sioux	St. Charles County, Mo.	968,000
	Meramec	St. Louis County, Mo.	832,000
Total coal			5,423,000
Nuclear	Callaway	Callaway County, Mo.	1,194,000
Hydroelectric	Osage	Lakeside, Mo.	240,000
	Keokuk	Keokuk, Ia.	136,000
Total hydroelectric			376,000
Pumped-storage	Taum Sauk	Reynolds County, Mo.	450,000
Oil (CTs)	Meramec	St. Louis County, Mo.	58,000
	Fairgrounds	Jefferson City, Mo.	54,000
	Mexico	Mexico, Mo.	53,000
	Moberly	Moberly, Mo.	53,000
	Moreau	Jefferson City, Mo.	53,000
	Howard Bend	St. Louis County, Mo.	39,000
	Venice	Venice, Ill.	(b)
Total oil			310,000
Natural gas (CTs)	Audrain[(c)]	Audrain County, Mo.	592,000
	Venice[(d)]	Venice, Ill.	487,000
	Goose Creek	Piatt County, Ill.	426,000
	Pinckneyville	Pinckneyville, Ill.	312,000
	Raccoon Creek	Clay County, Ill.	300,000
	Kinmundy[(d)]	Kinmundy, Ill.	206,000
	Peno Creek[(c)(d)]	Bowling Green, Mo.	188,000
	Meramec[(d)]	St. Louis County, Mo.	48,000
	Viaduct	Cape Girardeau, Mo.	25,000
	Kirksville	Kirksville, Mo.	13,000
Total natural gas			2,597,000
Total Ameren Missouri (UE)			10,350,000
Merchant Generation:			
Genco:			
Coal	Newton	Newton, Ill.	1,186,000
	Joppa Generating Station (EEI)[(e)]	Joppa, Ill.	1,002,000
	Coffeen	Coffeen, Ill.	895,000
	Meredosia	Meredosia, Ill.	203,000
	Hutsonville	Hutsonville, Ill.	151,000
Total coal			3,437,000
Oil	Meredosia	Meredosia, Ill.	166,000
	Hutsonville (Diesel)	Hutsonville, Ill.	3,000
Total oil			169,000
Natural gas (CTs)	Grand Tower	Grand Tower, Ill.	511,000
	Elgin	Elgin, Ill.	468,000
	Gibson City[(d)]	Gibson City, Ill.	230,000
	Joppa 7B	Joppa, Ill.	162,000
	Columbia[(f)]	Columbia, Mo.	108,000
	Joppa (EEI)[(e)]	Joppa, Ill.	74,000
Total natural gas			1,553,000
Total Genco			5,159,000
AERG:			
Coal	E.D. Edwards	Bartonville, Ill.	650,000
	Duck Creek	Canton, Ill.	410,000
Total AERG			1,060,000
Medina Valley:			
Natural gas	Medina Valley	Mossville, Ill.	44,000
Total Merchant Generation			6,263,000
Total Ameren			16,613,000

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(a) Net Kilowatt Capability is the generating capacity available for dispatch from the facility into the electric transmission grid.
(b) This facility is in extended reserve shutdown.
(c) There are economic development lease arrangements applicable to these CTs.
(d) One of the four CTs at Gibson City has the capability to operate on either oil or natural gas (dual fuel).
(e) Genco owns an 80% interest in EEI. This table reflects the full capability of EEI s facilities.
(f) In June 2010, Genco completed a sale of 25% of its Columbia CT facility to the city of Columbia, Missouri. Genco received cash proceeds of $18 million from the sale. The city of Columbia also holds two options to purchase additional ownership interests in the facility under two existing power purchase agreements. Columbia can exercise one option, as amended, for an additional 25% of the facility at the end of 2011 for a purchase price of $14.9 million, at the end of 2014 for a purchase price of $9.5 million, or at the end of 2020 for a purchase price of $4 million. The other option can be exercised for another 25% of the facility at the end of 2013 for a purchase price of $15.5 million, at the end of 2017 for a purchase price of $9.5 million, or at the end of 2023 for a purchase price of $4 million. On an annual basis, the city of Columbia purchases a total of 72 megawatts of capacity and energy generated by the facility under the two existing power purchase agreements. If the city of Columbia exercises one of the purchase options described above, the power purchase agreement associated with that option would be terminated.

The following table presents electric and natural gas utility-related properties for UE and AIC as of December 31, 2010:

	UE	AIC
Circuit miles of electric transmission lines	2,944	4,535
Circuit miles of electric distribution lines	33,031	45,531
Circuit miles of electric distribution lines underground	22%	15%
Miles of natural gas transmission and distribution mains	3,268	18,128
Propane-air plants	1	-
Underground gas storage fields	-	12
Billion cubic feet of total working capacity of underground gas storage fields	-	25

Our other properties include office buildings, warehouses, garages, and repair shops.

With only a few exceptions, we have fee title to all principal plants and other units of property material to the operation of our businesses, and to the real property on which such facilities are located (subject to mortgage liens securing our outstanding first mortgage bonds and credit facility indebtedness and to certain permitted liens and judgment liens). The exceptions are as follows:

A portion of UE s Osage plant reservoir, certain facilities at UE s Sioux plant, most of UE s Peno Creek and Audrain CT facilities, Genco s Columbia CT facility, Medina Valley s generating facility, certain substations, and most transmission and distribution lines and gas mains are situated on lands occupied under leases, easements, franchises, licenses, or permits. The United States or the state of Missouri may own or may have paramount rights to certain lands lying in the bed of the Osage River or located between the inner and outer harbor lines of the Mississippi River on which certain of UE s generating and other properties are located.

The United States, the state of Illinois, the state of Iowa, or the city of Keokuk, Iowa, may own or may have paramount rights with respect to certain lands lying in the bed of the Mississippi River on which a portion of UE s Keokuk plant is located.

Substantially all of the properties and plant of UE and AIC are subject to the first liens of the indentures securing their mortgage bonds.

UE has conveyed most of its Peno Creek CT facility to the city of Bowling Green, Missouri, and leased the facility back from the city through 2022. Under the terms of this capital lease, UE is responsible for all operation and maintenance for the facility. Ownership of the facility will transfer to UE at the expiration of the lease, at which time the property and plant will become subject to the lien of any outstanding UE first mortgage bond indenture.

UE operates a CT facility located in Audrain County, Missouri. UE has rights and obligations as lessee of the CT facility under a long-term lease with Audrain County. The lease term will expire on December 1, 2023. Under the terms of this capital lease, UE is responsible for all operation and maintenance for the facility. Ownership of the facility will transfer to UE at the expiration of the lease, at which time the property and plant will become subject to the lien of any outstanding UE first mortgage bond indenture.

ITEM 3. LEGAL PROCEEDINGS.

We are involved in legal and administrative proceedings before various courts and agencies with respect to matters that arise in the ordinary course of business, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings, except as otherwise disclosed in this report, will not have a material adverse effect on our results of operations, financial position, or liquidity. Risk of loss is mitigated, in some cases, by insurance or contractual or statutory indemnification. We believe that we have established appropriate reserves for potential losses. Material legal and administrative proceedings, which are discussed in Note 2 Rate and Regulatory Matters, and Note 15 Commitment and Contingencies under part II, Item 8, of this report and incorporated herein by reference, include the following:

- appeal of the MoPSC January 2009 and May 2010 electric rate orders;
- an electric rate case proceeding for UE pending before the MoPSC;
- the MoPSC staff s FAC prudence review pending before the MoPSC;
- appeal of the MoPSC rules implementing the Missouri renewable energy portfolio requirement;

appeal of certain aspects of the ICC s 2010 rate orders;
electric and natural gas rate proceedings for AIC pending before the ICC;
the EPA s Clean Air Act-related litigation filed against UE and NSR investigations at Genco and AERG;
remediation matters associated with MGP and waste disposal sites of the Ameren Companies;
litigation associated with the breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility; and
asbestos-related litigation associated with Ameren, UE, AIC and Genco.

ITEM 4. [REMOVED AND RESERVED].
EXECUTIVE OFFICERS OF THE REGISTRANTS (ITEM 401(b) OF REGULATION S-K):

The executive officers of the Ameren Companies, including major subsidiaries, as of December 31, 2010, (except as otherwise noted) are listed below, along with their ages as of December 31, 2010, all positions and offices held with the Ameren Companies, tenure as officer, and business background for at least the last five years. Some executive officers hold multiple positions within the Ameren Companies; their titles are given in the description of their business experience.

AMEREN CORPORATION:

Name	Age	Positions and Offices Held
Thomas R. Voss	63	Chairman, President and Chief Executive Officer, and Director

Voss joined UE in 1969. He was elected senior vice president of UE, CIPS, and Ameren Services in 1999, of Genco in 2001, of CILCO in 2003, and of IP in 2004. In 2003, Voss was elected president of Genco; he relinquished his presidency of this company in 2004. In 2006, he was elected executive vice president of UE, CIPS, CILCO and IP. In 2007, Voss was elected chairman, president, and chief executive officer of UE. He relinquished his positions at CIPS, CILCO and IP in 2007. In 2009, Voss was elected president and chief executive officer of Ameren; at that time, he relinquished his other positions. In 2010, the Ameren board of directors elected Voss to the position of chairman of the board. He has been a member of the Ameren board since 2009.

Name	Age	Positions and Offices Held
Martin J. Lyons, Jr.	44	Senior Vice President and Chief Financial Officer

Lyons joined Ameren, UE, CIPS, Genco, and Ameren Services in 2001 as controller. He was elected controller of CILCO in 2003. He was also elected vice president of Ameren, UE, CIPS, Genco, CILCO, and Ameren Services in 2003 and vice president and controller of IP in 2004. In 2007, his positions at UE were changed to vice president and principal accounting officer. In 2008, Lyons was elected senior vice president and principal accounting officer of the Ameren Companies. In 2009, Lyons was also elected chief financial officer of the Ameren Companies. With the AIC Merger in 2010, Lyons remained senior vice president, chief financial officer and principal accounting officer at AIC.

Name	Age	Positions and Offices Held
Gregory L. Nelson	53	Senior Vice President and General Counsel (Effective March 2, 2011)

Nelson joined UE in 1995 as a manager in the tax department and assumed a similar position with Ameren Services in 1998. Nelson was elected vice president and tax counsel of Ameren Services in 1999 and vice president of UE, CIPS, CILCO and Genco in 2003 and of IP in 2004. In 2010, Nelson was elected vice president, tax and deputy general counsel of Ameren Services and remained vice president of UE, CIPS, CILCO, IP and Genco. With the AIC Merger in 2010, Nelson remained vice president at AIC. Effective March 2, 2011, Nelson will assume the positions of senior vice president and general counsel of Ameren, UE, AIC, Genco and Ameren Services.

Name	Age	Positions and Offices Held
Jerre E. Birdsong	56	Vice President and Treasurer

Birdsong joined UE in 1977 and was elected treasurer of UE in 1993. He was elected treasurer of Ameren, CIPS, and Ameren Services in 1997 and of Genco in 2000. In addition to being treasurer, in 2001 he was elected vice president at Ameren, UE, CIPS, Ameren Services and Genco. Additionally, he was elected vice president and treasurer of CILCO in 2003 and of IP in 2004. With the AIC Merger in 2010, Birdsong, remained vice president and treasurer at AIC.

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SUBSIDIARIES:

Name	Age	Positions and Offices Held
Warner L. Baxter	49	Chairman, President and Chief Executive Officer (UE)

Baxter joined UE in 1995. He was elected senior vice president, finance, of Ameren, UE, CIPS, Ameren Services, and Genco in 2001 and of CILCO in 2003. Baxter was elected to the positions of executive vice president and chief financial officer of Ameren, UE, CIPS, Genco, CILCO and Ameren Services in 2003 and of IP in 2004. He was elected chairman, president, chief executive officer and chief financial officer of Ameren Services in 2007. In 2009, Baxter was elected chairman, president and chief executive officer of UE; at that time, he relinquished his other positions.

Maureen A. Borkowski	53	Chairman, President and Chief Executive Officer (ATX)

Borkowski joined UE in 1981. She left the company for a period of time before rejoining Ameren in 2005. Borkowski has led Ameren s transmission operations since 2005 as vice president, transmission, of Ameren Services. In 2010, Borkowski was elected president and chief executive officer of ATX. Effective March 2, 2011, Borkowski will also assume the position of Chairman of ATX.

Scott A. Cisel	57	Chairman, President and Chief Executive Officer (AIC)

Cisel joined CILCO in 1975. He was named senior vice president and leader of CILCO s Sales and Marketing Business Unit in 2001. Cisel assumed the positions of vice president and chief operating officer of CILCO in 2003, upon Ameren s acquisition of that company. In 2004, Cisel was elected vice president of UE and president and chief operating officer of CIPS, CILCO and IP. In 2007, Cisel was elected chairman and chief executive officer of CIPS, CILCO and IP, in addition to his position as president. He relinquished his position at UE in 2007. With the AIC Merger in 2010, Cisel remained chairman, president and chief executive officer at AIC.

Daniel F. Cole	57	Chairman, President and Chief Executive Officer (Ameren Services)

Cole joined UE in 1976. He was elected senior vice president of UE and Ameren Services in 1999 and of CIPS in 2001. He was elected president of Genco in 2001; he relinquished that position in 2003. He was elected senior vice president of CILCO in 2003 and of IP in 2004. In 2009, Cole was elected chairman, president and chief executive officer of Ameren Services and remained senior vice president of UE, CIPS, CILCO and IP. With the AIC Merger in 2010, Cole remained senior vice president at AIC.

Karen C. Foss	66	Senior Vice President (Ameren Services)

Foss joined UE in 2007 as vice president of public relations. She was elected senior vice president, communications and brand management, of Ameren Services in 2009. Foss relinquished her position at UE in 2009. Prior to joining UE, Foss was a news anchor at KSDK-TV in St. Louis, Missouri. Foss will retire from Ameren Services in July 2011.

Adam C. Heflin	46	Senior Vice President and Chief Nuclear Officer (UE)

Heflin joined UE in 2005 as vice president of nuclear operations and was elected senior vice president and chief nuclear officer of UE in 2008.

Richard J. Mark	55	Senior Vice President (UE)

Mark joined Ameren Services in 2002 as vice president of customer service. In 2003, he was elected vice president of governmental policy and consumer affairs at Ameren Services, with responsibility for government affairs, economic development and community relations for Ameren s operating utility companies. He was elected senior vice president, customer operations of UE in 2005, with responsibility for Missouri energy delivery. In 2007, Mark relinquished his position at Ameren Services.

Michael L. Moehn	41	Senior Vice President (Ameren Services)

Moehn joined Ameren Services in 2000. He was named director of Ameren Services corporate modeling and transaction support in 2001 and elected vice president of business services for Resources Company in 2002. In 2004, Moehn was elected vice president of corporate planning of Ameren Services and relinquished his position at Resources Company. In 2008, he was elected senior vice president, corporate planning and business risk management of Ameren Services.

Charles D. Naslund	58	Senior Vice President (UE) (Effective March 2, 2011)

Naslund joined UE in 1974. He was elected vice president of power operations at UE in 1999, vice president of Ameren Services in 2000 and vice president of nuclear operations at UE in 2004. He relinquished his position at Ameren Services in 2001. Naslund was elected senior vice president and chief nuclear officer at UE in 2005. In 2008, he was elected chairman, president and chief executive officer of Resources Company and chairman and president of Genco. Naslund relinquished his positions at UE in 2008. Effective March 2, 2011, Naslund will assume the position of senior vice president, generation and environmental projects of UE and relinquish his positions of chairman, president and chief executive officer of Resources Company and chairman and president of Genco.

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Name	Age	Positions and Offices Held
Andrew M. Serri	49	President and Chief Executive Officer (Marketing Company)

Serri joined Marketing Company as vice president of sales and marketing in 2000. He was elected vice president of marketing and trading of Ameren Services in 2004, before being elected president and chief executive officer of Marketing Company that same year. He relinquished his position at Ameren Services in 2007.

Steven R. Sullivan	50	Chairman, President and Chief Executive Officer (Resources Company) and Chairman and President (Genco) (Effective March 2, 2011)

Sullivan joined Ameren, UE, CIPS and Ameren Services in 1998 as vice president, general counsel and secretary. He added those positions at Genco in 2000. In 2003, Sullivan was elected vice president, general counsel and secretary of CILCO. He was elected to his present positions of senior vice president, general counsel and secretary of Ameren, UE, CIPS, Genco, CILCO and Ameren Services in 2003 and of IP in 2004. With the AIC Merger in 2010, Sullivan remained senior vice president, general counsel and secretary at AIC. Effective March 2, 2011, Sullivan will assume the positions of chairman, president and chief executive officer of Resources Company and chairman and president of Genco and relinquish his positions of senior vice president and general counsel of Ameren, UE, AIC, Genco and Ameren Services. Sullivan remains secretary of Ameren, UE, AIC, Genco and Ameren Services.

Officers are generally elected or appointed annually by the respective board of directors of each company, following the election of board members at the annual meetings of shareholders. No special arrangement or understanding exists between any of the above-named executive officers and the Ameren Companies nor, to our knowledge, with any other person or persons pursuant to which any executive officer was selected as an officer. There are no family relationships among the officers. Except for Karen C. Foss, all of the above-named executive officers have been employed by an Ameren company for more than five years in executive or management positions.

PART II

ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Ameren s common stock is listed on the NYSE (ticker symbol: AEE). Ameren common shareholders of record totaled 66,808 on January 31, 2011. The following table presents the price ranges, closing prices, and dividends declared per Ameren common share for each quarter during 2010 and 2009.

	High	Low	Close	Dividends Declared
AEE 2010 Quarter Ended:				
March 31	**$ 28.27**	**$ 24.14**	**$ 26.08**	**38 1/2¢**
June 30	**26.92**	**23.09**	**23.77**	**38 1/2**
September 30	**28.99**	**23.45**	**28.40**	**38 1/2**
December 31	**29.89**	**27.65**	**28.19**	**38 1/2**
AEE 2009 Quarter Ended:				
March 31	$ 35.35	$ 19.51	$ 23.19	38 1/2¢
June 30	25.25	21.75	24.89	38 1/2
September 30	27.66	23.09	25.28	38 1/2
December 31	28.67	23.78	27.95	38 1/2

There is no trading market for the common stock of UE, AIC and Genco. Ameren holds all outstanding common stock of UE and AIC; Resources Company holds all outstanding common stock of Genco.

The following table sets forth the quarterly common stock dividend payments made by Ameren and its subsidiaries during 2010 and 2009:

	2010				2009			
(In millions)	**Quarter Ended**				**Quarter Ended**			
Registrant	**December 31**	**September 30**	**June 30**	**March 31**	**December 31**	**September 30**	**June 30**	**March 31**
UE	**$ 59**	**$ 60**	**$ 58**	**$ 58**	$ 5	$ 71	$ 47	$ 52
AIC	**33**	**33**	**34**	**33**	86	12	-	-

Genco	**-**	**-**	**-**	**-**	-	-	20	23
Nonregistrants	**-**	**-**	**-**	**-**	-	-	15	7
Ameren	**$ 92**	**$ 93**	**$ 92**	**$ 91**	$ 91	$ 83	$ 82	$ 82

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On February 9, 2011, the board of directors of Ameren declared a quarterly dividend on Ameren s common stock of 38.5 cents per share. The common share dividend is payable March 31, 2011, to stockholders of record on March 9, 2011.

For a discussion of restrictions on the Ameren Companies payment of dividends, see Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report.

Purchase of Equity Securities

The following table presents Ameren Corporation s purchases of equity securities reportable under Item 703 of Regulation S-K:

Period	(a) Total Number of Shares (or Units) Purchased[(a)]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased As Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) That May Yet Be Purchased Under the Plans or Programs
October 1 October 31, 2010	948	$ 29.23	-	-
November 1 November 30, 2010	-	-	-	-
December 1 December 31, 2010	-	-	-	-
Total	948	$ 29.23	-	-

(a) The shares of Ameren common stock were purchased by Ameren in open-market transactions pursuant to Ameren s 2006 Omnibus Incentive Compensation Plan in satisfaction of Ameren s obligation to distribute shares of common stock for vested performance units. Ameren does not have any publicly announced equity securities repurchase plans or programs.

The following table presents AIC s purchases of equity securities reportable under Item 703 of Regulation S-K:

Period	(a) Total Number of Shares (or Units) Purchased[(a)]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased As Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) That May Yet Be Purchased Under the Plans or Programs
October 1 October 31, 2010	-	$ -	-	-
November 1 November 30, 2010	68	73.66	-	-
December 1 December 31, 2010	-	-	-	-
Total	68	$ 73.66	-	-

(a) The shares of CIPS preferred stock were purchased by AIC as a result of CIPS preferred stockholders exercising their dissenters rights under Illinois law.

UE and Genco did not purchase equity securities reportable under Item 703 of Regulation S-K during the period from October 1, 2010 to December 31, 2010.

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Performance Graph

The following graph shows Ameren s cumulative total shareholder return during the five years ended December 31, 2010. The graph also shows the cumulative total returns of the S&P 500 Index and the Edison Electric Institute Index (EEI Index), which comprises most investor-owned electric utilities in the United States. The comparison assumes that $100 was invested on December 31, 2005, in Ameren common stock and in each of the indices shown, and it assumes that all of the dividends were reinvested.

December 31,	2005	2006	2007	2008	2009	2010
Ameren	$ 100	$ 110.11	$ 116.65	$ 76.30	$ 68.13	**$ 72.80**
S&P 500 Index	100	115.79	122.15	76.95	97.31	**111.97**
EEI Index	100	120.76	140.76	104.30	115.47	**123.60**

Ameren management cautions that the stock price performance shown in the graph above should not be considered indicative of potential future stock price performance.

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ITEM 6. SELECTED FINANCIAL DATA.

For the years ended December 31,

(In millions, except per share amounts)	2010	2009	2008	2007	2006
Ameren:					
Operating revenues[a]	**$ 7,638**	$ 7,135	$ 7,869	$ 7,562	$ 6,895
Operating income[a][b]	**916**	1,416	1,362	1,359	1,188
Net income attributable to Ameren Corporation[a]	**139**	612	605	618	547
Common stock dividends	**368**	338	534	527	522
Earnings per share basic and diluted[a]	**0.58**	2.78	2.88	2.98	2.66
Common stock dividends per share	**1.54**	1.54	2.54	2.54	2.54
As of December 31:					
Total assets	**$ 23,515**	$ 23,702	$ 22,671	$ 20,752	$ 19,662
Long-term debt, excluding current maturities	**6,853**	7,111	6,554	5,689	5,285
Preferred stock subject to mandatory redemption	**-**	-	-	16	17
Total Ameren Corporation stockholders equity	**7,730**	7,856	6,963	6,752	6,583
UE:					
Operating revenues	**$ 3,197**	$ 2,874	$ 2,960	$ 2,961	$ 2,823
Operating income	**711**	566	514	590	620
Net income available to common stockholder	**364**	259	245	336	343
Dividends to parent	**235**	175	264	267	249
As of December 31:					
Total assets	**$ 12,504**	$ 12,219	$ 11,529	$ 10,903	$ 10,290
Long-term debt, excluding current maturities	**3,949**	4,018	3,673	3,208	2,934
Total stockholders equity	**4,153**	4,057	3,562	3,601	3,153
AIC:					
Operating revenues	**$ 3,014**	$ 2,984	$ 3,508	$ 3,380	$ 3,353
Operating income	**498**	363	191	195	272
Income from continuing operations	**212**	133	41	56	124
Net income available to common stockholder	**248**	241	87	114	137
Dividends to parent	**133**	98	60	101	115
As of December 31:					
Total assets[c]	**$ 7,406**	$ 8,298	$ 8,023	$ 7,101	$ 6,778
Long-term debt, excluding current maturities	**1,657**	1,847	1,850	1,618	1,368
Preferred stock subject to mandatory redemption	**-**	-	-	16	17
Total stockholders equity	**2,576**	3,072	2,655	2,635	2,612
Genco:					
Operating revenues	**$ 1,126**	$ 1,148	$ 1,422	$ 1,298	$ 1,359
Operating income[b]	**62**	324	551	468	346
Net income (loss) attributable to Ameren Energy Generating Company	**(39)**	160	286	230	150
Dividends to parent	**-**	43	221	199	223
As of December 31:					
Total assets	**$ 2,611**	$ 2,920	$ 2,592	$ 2,288	$ 2,150
Long-term debt, excluding current maturities	**824**	823	774	474	474
Subordinated intercompany notes (current)	**-**	176	145	172	206
Total Ameren Energy Generating Company stockholder s equity	**998**	1,004	868	857	740

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

(b) Includes goodwill and other asset impairment pretax charges of $589 million and $170 million recorded at Ameren and Genco, respectively, during the year ended December 31, 2010.

(c) Includes total assets from discontinued operations of $1,117 million, $1,081 million, $865 million, and $635 million at December 31, 2009, 2008, 2007, and 2006, respectively.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

OVERVIEW

Ameren Executive Summary

Operations

During 2010, disciplined cost management, strong customer sales and rate relief allowed Ameren to overcome the financial impact of weak wholesale power prices and higher fuel and related transportation costs. Ameren also returned its newly rebuilt Taum Sauk pumped-storage hydroelectric facility to service; installed major environmental controls at two coal-fired plants; simplified its corporate structure by merging its Illinois delivery utilities into a single company and by moving AERG under Resources Company, where Ameren s other Merchant Generation assets reside; launched plans for growing its transmission business; and improved its safety and customer satisfaction performance.

In 2010, UE and AIC were authorized to increase rates. UE obtained approval from the MoPSC in May 2010 to increase electric rates by $230 million annually and then in February 2011 to increase natural gas rates by $9 million annually. These rate increases have been necessary to recover the cost of infrastructure investments, higher fuel costs, and other operating expenses. In November 2010, AIC received an order on rehearing from the ICC on issues arising from the ICC s amended order of May 2010. The rehearing order authorized an additional $25 million annual rate increase, bringing the total annual revenue increase to $40 million.

Ongoing litigation exists surrounding appeals of certain aspects of UE s two most recent electric rate orders. In February 2011, the Missouri Office of Public Counsel (MoOPC) made a filing with the MoPSC in which the MoOPC argued that a December 20, 2010 stay, granted by the Circuit Court of Cole County, Missouri (Circuit Court), of UE s 2010 electric rate increase, as it applies to four industrial customers, should apply to all UE customers. UE disagrees with the MoOPC s argument. On December 20, 2010, the Circuit Court found that four industrial customers appealing UE s 2010 electric rate increase could pay the portions of their bills, representing increases from previously approved levels, into the Circuit Court s registry pending resolution of these appeals. This effectively stayed the rate increases for those parties. UE disagrees with the Circuit Court s ruling granting these industrial customers a stay. At this time, UE does not believe any aspect of the 2009 and 2010 electric rate increases authorized by the 2009 and 2010 Missouri electric rate orders are probable of refund to UE s customers.

UE and AIC also have pending rate cases. In September 2010, UE filed for a $263 million annual electric rate increase. On February 8, 2011, other parties filed their initial testimony. The staff of the MoPSC recommended a rate increase of $45 million to $99 million. A key reason that the staff s recommendation is considerably lower than

UE s request is the staff s use of a return on equity range of 8.25% to 9.25%, compared to UE s request of 10.9%. While UE strongly disagrees with elements of the MoPSC s staff and other parties initial recommendations, this case is still in its early stages with a decision not expected until July 2011. On February 18, 2011, AIC filed an electric and natural gas delivery rate case with the ICC requesting a $111 million aggregate increase in annual revenues. This request is based on a future test year ending December 31, 2012, with an ICC decision expected in January 2012. The use of a future test year is designed to better match AIC s 2012 rate levels to its expected 2012 costs, reducing regulatory lag and providing an improved opportunity to earn a fair return on investment. In addition to these regulatory developments in Ameren s state jurisdictions, Ameren is awaiting action from FERC on its August 2010 filing for pre-approval of supportive rate treatment for its proposed Grand Rivers regional electric transmission projects.

2011 could be a pivotal year in environmental regulation. The EPA is scheduled to finalize its proposed CATR, which is aimed at reducing emissions of SO_2 and NO_x. Further, the EPA is scheduled to propose requirements for retrofitting power plants with MACT to reduce hazardous air pollutants such as mercury and acid gases, cooling water standards, and rules for reducing greenhouse gas emissions. These rules are expected to impose additional costs that could be substantial to Ameren and, therefore, its customers. Ameren is continually evaluating these changing environmental standards for their impact on its power plants and is focused on meeting these requirements in the most cost effective manner possible.

Ameren remains focused on earning fair returns on investments at its rate-regulated utilities by seeking consistent, constructive regulatory outcomes, including mechanisms that reduce regulatory lag, like the use of a future test year in AIC s pending electric and natural gas rate case filing. Further, Ameren continues to focus on disciplined cost management, including aligning its spending with the level of rates authorized by its regulators. In 2010, Ameren s rate-regulated utilities narrowed the gap between their core earnings and their allowed returns on equity by almost three percent and by more than one percent on a weather-normalized basis. The projected 2011 return levels are expected to be below what is currently authorized and what Ameren considers appropriate. Ameren believes its pending rate cases, cost control efforts and its ongoing work to improve its regulatory frameworks will allow its rate-regulated utilities to further narrow the gap between earned and allowed returns.

Ameren s Merchant Generation business continues to aggressively manage operating and capital costs so that this business remains stable during this period of low power prices and well-positioned to benefit from an eventual expected power price recovery. In 2010, Ameren s Merchant Generation business further lowered its cost structure to enhance its long-term competitiveness.

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Earnings

Ameren reported net income of $139 million, or 58 cents per share, for 2010 compared with net income of $612 million, or $2.78 per share, in 2009. The main factor contributing to the decline in earnings in 2010 compared with 2009 was noncash goodwill and other asset impairment charges of $522 million, or $2.19 per share, recorded in 2010 related to Ameren s Merchant Generation business. These charges reflected a decline in the value of Ameren s Merchant Generation business, principally as a result of sustained lower power prices and the potential enactment of more stringent environmental regulations. Ameren s earnings were also lower in 2010, compared with 2009, because of reduced Merchant Generation margins, as a result of lower realized power prices and higher fuel and related transportation costs, and higher depreciation and amortization expense. Offsetting factors included higher electricity sales, which benefited from warmer summer weather, new utility rates in Missouri and Illinois, lower financing costs, and disciplined cost management.

Liquidity

Cash flows from operations of $1.8 billion were used to pay dividends to common stockholders of $368 million and to fund capital expenditures of $1.0 billion. At December 31, 2010, Ameren, on a consolidated basis, had available liquidity, in the form of cash on hand and amounts available under its existing credit facilities, of approximately $1.9 billion, which was equivalent to the amount of available liquidity at December 31, 2009.

Capital Spending

Capital expenditures decreased $673 million in 2010 compared with 2009. The reduction was a result of fewer planned expenditures for the distribution system and power plant improvements, less expenditures required to repair severe storm damage, and the completion of power plant scrubber projects in the Merchant Generation business during 2009 and early 2010.

From 2011 through 2015, cumulative capital spending is projected to range between $6.4 billion and $8.2 billion. Much of this spending is at Ameren s rate-regulated utilities, including $265 million at ATX to expand its electric transmission assets. This five-year plan also includes significant investments in environmental projects, including the cost of installing scrubbers for two units of Genco s Newton plant and for two units of a UE plant.

In addition to existing laws and regulations governing our facilities, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren, UE and Genco, that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; revised ambient air quality standards for SO_2 and NO_x emissions increasing the

stringency of the existing ozone ambient air quality standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is also expected to propose new regulations under the Clean Water Act, that could require significant capital expenditures such as new water intake structures or cooling towers at our power plants; NSPS and emission guidelines for greenhouse gas emissions applicable to new and existing electric generating units; and a MACT standard for the control of hazardous air pollutants, such as mercury and acid gases from power plants. Such new regulations may be challenged with lawsuits, so the timing of their ultimate implementation is uncertain. Although many details of these future regulations are unknown, the combined effects of the new and proposed environmental regulations may result in significant capital expenditures over the next five to eight years for Ameren, UE and Genco.

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005, administered by FERC. Ameren s primary assets are the common stock of its subsidiaries. Ameren s subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. These subsidiaries operate, as the case may be, rate-regulated electric generation, transmission, and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois. Dividends on Ameren s common stock and the payment of other expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren s principal subsidiaries are listed below. See Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report for a detailed description of our principal subsidiaries.

- UE operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri.
- AIC operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.
- Genco operates a merchant electric generation business in Illinois and Missouri. Genco has an 80% ownership interest in EEI.

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed a two-step corporate internal reorganization. The first step of the reorganization was the AIC Merger, pursuant to the terms of the agreement, dated as of April 13, 2010. Upon consummation of the AIC Merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. The AIC Merger and the distribution of AERG stock were accounted for as

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transactions between entities under common control. In accordance with authoritative accounting guidance, assets and liabilities transferred between entities under common control were accounted for at the historical cost basis of the common parent, Ameren, as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren s historical cost basis in AIC included purchase accounting adjustments related to Ameren s acquisition of CILCORP in 2003. AIC accounted for the AERG distribution as a spinoff. AIC transferred AERG to Ameren based on AERG s carrying value. AIC determined that the operating results of AERG qualified for discontinued operations presentation; therefore, AIC has segregated AERG s operating results and presented them separately as discontinued operations for all periods prior to October 1, 2010, in this report. For Ameren s financial statements, AERG s results of operations remained classified as continuing operations. See Note 16 Corporate Reorganization and Discontinued Operations under Part II, Item 8, for additional information.

Ameren has various other subsidiaries responsible for the marketing of power, management of commodity risks, and provision of other shared services. Ameren has an 80% ownership interest in EEI, which until February 29, 2008, was held 40% by UE and 40% by Development Company. UE reported EEI under the equity method until February 29, 2008. Effective February 29, 2008, UE s and Development Company s ownership interests in EEI were transferred to Resources Company through an internal reorganization. UE s interest in EEI was transferred at book value indirectly through a dividend to Ameren. Effective January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% stock ownership interest in EEI to Genco through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco accounted for the transfer at the historical carrying value of the parent (Ameren) as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren s historical cost basis in EEI included purchase accounting adjustments relating to Ameren s acquisition of an additional 20% ownership interest in EEI in 2004. This transfer required Genco s prior-period financial statements to be retrospectively combined for all periods presented. Consequently, Genco s prior-period consolidated financial statements reflect EEI as if it had been a subsidiary of Genco. Ameren and Genco consolidate EEI for financial reporting purposes. See Note 14 Related Party Transactions under Part II, Item 8, for additional information.

The financial statements of Ameren are prepared on a consolidated basis and therefore include the accounts of its majority-owned subsidiaries. All significant intercompany transactions have been eliminated. All tabular dollar amounts are expressed in millions, unless otherwise indicated.

In addition to presenting results of operations and earnings amounts in total, we present certain information in

cents per share. These amounts reflect factors that directly affect Ameren s earnings. We believe this per share information helps readers to understand the impact of these factors on Ameren s earnings per share. All references in this report to earnings per share are based on average diluted common shares outstanding.

RESULTS OF OPERATIONS

Our results of operations and financial position are affected by many factors. Weather, economic conditions, and the actions of key customers or competitors can significantly affect the demand for our services. Our results are also affected by seasonal fluctuations: winter heating and summer cooling demands. The vast majority of Ameren s revenues are subject to state or federal regulation. This regulation has a material impact on the price we charge for our services. Merchant Generation sales are also subject to market conditions for power. We principally use coal, nuclear fuel, natural gas, and oil for fuel in our operations. The prices for these commodities can fluctuate significantly due to the global economic and political environment, weather, supply and demand, and many other factors. We have natural gas cost recovery mechanisms for our Illinois and Missouri gas delivery service businesses, purchased power cost recovery mechanisms for our Illinois electric delivery service businesses, and a FAC for our Missouri electric utility business. See Note 2 Rate and Regulatory Matters under Part II, Item 8, for a discussion of pending rate cases in Missouri and Illinois. Fluctuations in interest rates and conditions in the capital and credit markets affect our cost of borrowing and our pension and postretirement benefits costs. We employ various risk management strategies to reduce our exposure to commodity risk and other risks inherent in our business. The reliability of our power plants and transmission and distribution systems and the level of purchased power costs, operations and maintenance costs, and capital investment are key factors that we seek to control to optimize our results of operations, financial position, and liquidity.

Earnings Summary

Net income attributable to Ameren Corporation was $139 million, or $0.58 per share, for 2010, $612 million, or $2.78 per share, for 2009, and $605 million, or $2.88 per share, for 2008.

2010 versus 2009

Net income attributable to Ameren Corporation decreased $473 million and its earnings per share decreased $2.20 in 2010 compared with 2009. Net income attributable to Ameren Corporation increased in the Ameren Missouri and Ameren Illinois segments by $105 million and $81 million, respectively, in 2010 compared with 2009, while net income attributable to Ameren Corporation in the Merchant Generation segment decreased by $656 million in 2010 compared with 2009.

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Compared with 2009 earnings per share, 2010 earnings were negatively affected by:

- the 2010 impairment of goodwill, intangible assets, and long-lived assets within the Merchant Generation segment due to the sustained decline in market prices for electricity, industry market multiples becoming observable at lower levels than previously estimated, and potentially more stringent environmental regulations ($2.19 per share);
- lower realized electric margins in the Merchant Generation segment largely due to lower realized revenue per megawatthour sold and higher fuel and related transportation costs (79 cents per share). This amount excludes the unfavorable impacts of net unrealized MTM activity on nonqualifying power hedges discussed below. See Outlook for expected trends in future coal, transportation and power prices;
- higher dilution (23 cents per share) caused by an increase in the average number of common shares outstanding, largely because of a September 2009 common stock issuance, the proceeds of which were used to make investments in Ameren s rate-regulated utilities. The impact of dilution was offset by higher earned returns on investments at Ameren s rate-regulated utilities and lower financing costs;
- costs associated with the Callaway nuclear plant s scheduled refueling and maintenance outage in 2010. There was no Callaway refueling and maintenance outage in 2009 (12 cents per share);
- increased depreciation and amortization expenses, primarily due to capital additions placed in-service at the Merchant Generation segment in late 2009 and early 2010, excluding the impacts at UE of the May 2010 MoPSC electric rate order discussed below (9 cents per share);
- a reduced gain between years from net unrealized MTM activity on nonqualifying power hedges and from changes in the market value of investments used to support Ameren s deferred compensation plans (6 cents per share); and
- the impact of a federal tax change resulting from a U.S. health care reform bill that was enacted in 2010 (6 cents per share).

Compared with 2009 earnings per share, 2010 earnings were favorably affected by:

- the impact of weather conditions on energy demand (estimated at 40 cents per share);
- higher UE electric rates pursuant to the MoPSC 2009 and 2010 electric rate orders effective March 1, 2009, and June 21, 2010, respectively, offset by the adoption of the life span depreciation methodology and increased regulatory asset amortization as directed by the MoPSC 2010 electric rate order (27 cents per share);
- the favorable impact on electric and natural gas margins in our rate-regulated businesses from higher weather-normalized sales volumes (exclusive of higher sales to Noranda discussed below), largely due to improved economic conditions and higher wholesale sales margins at UE because of additional customers and higher-priced wholesale sales contracts, among other things (20 cents per share);
- increased UE sales to Noranda as its smelter plant gradually returned to full capacity by the end of the first quarter of 2010 after a January 2009 severe ice storm significantly reduced the plant s capacity (11 cents per share);
- a reduction in financing expenses caused primarily by an increase in the allowance for funds used during construction at UE for the installation of two scrubbers at its Sioux plant (10 cents per share);
- higher AIC electric and natural gas net delivery rates pursuant to the ICC 2010 rate orders, which became effective in May and November 2010 (9 cents per share); and
- reduced charges in 2010 relating to workforce reductions through voluntary and involuntary separation programs (4 cents per share).

The cents per share information presented above is based on average shares outstanding in 2009.

2009 versus 2008

Net income attributable to Ameren Corporation increased $7 million and its earnings per share decreased 10 cents in 2009 compared with 2008. Net income attributable to Ameren Corporation increased in the Ameren Illinois and Ameren Missouri segments by $92 million and $25 million, respectively, in 2009 compared with 2008, while net income attributable to Ameren Corporation in the Merchant Generation segment decreased by $105 million in 2009 compared with 2008.

Compared with 2008 earnings per share, 2009 earnings were negatively affected by:

- higher dilution and financing costs caused by an increase in the average number of common shares outstanding, largely because of a September 2009 common stock issuance (31 cents per share);
- the impact on electric and natural gas margins in our rate-regulated businesses of higher net fuel costs at UE resulting from higher coal and related transportation costs, and lower sales prices for excess power, and lower demand (exclusive of weather impacts), among other things

(30 cents per share);

the absence in 2009 of the benefit of a settlement agreement reached with a coal mine owner that reimbursed Genco, in the form of a lump-sum payment, for increased costs for coal and transportation incurred in 2008 and 2009 due to the premature closure of an Illinois mine and contract termination (18 cents per share);

the impact of milder weather conditions on energy demand (estimated at 15 cents per share);

increased depreciation and amortization expenses primarily because of capital additions at UE and at the Merchant Generation segment and additional

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amortization of UE s regulatory assets as a result of the MoPSC s January 2009 electric rate order (12 cents per share);
reduced sales to Noranda after a January 2009 severe ice storm significantly reduced its smelter plant s capacity (11 cents per share);
the absence in 2009 of a MoPSC rate order establishing two separate regulatory assets for previously incurred storm and MISO related costs (11 cents per share);
increased expense related to workforce reductions through voluntary and involuntary separation programs and long-lived asset impairment charges recorded primarily at Genco in 2009 (7 cents per share);
increased taxes other than income taxes, primarily because of higher property taxes (6 cents per share);
lower realized electric margins in the Merchant Generation segment largely due to lower sales volumes and higher fuel and related transportation costs (5 cents per share); and
increased distribution system reliability expenditures (5 cents per share).

Compared with 2008 earnings per share, 2009 earnings were favorably affected by:

higher AIC electric and natural gas delivery rates pursuant to an ICC rate order, which became effective on October 1, 2008 (40 cents per share);
higher UE electric rates pursuant to a MoPSC rate order, which became effective on March 1, 2009 (40 cents per share);
favorable net unrealized MTM activity on derivatives and from changes in the market value of investments used to support Ameren s deferred compensation plans (21 cents per share);
decreased plant operations and maintenance expense because less work was undertaken as a result of cost-containment initiatives in response to weak economic conditions (15 cents per share);
the absence in 2009 of a Callaway nuclear plant refueling and maintenance outage (9 cents per share);
the absence in 2009 of asset impairment charges recorded to adjust the carrying value of AERG s Indian Trails and Sterling Avenue generating facilities to their estimated fair values as of December 31, 2008 (6 cents per share); and
the reduced impact in 2009 of the electric rate relief and customer assistance programs provided to certain AIC electric customers under the 2007 Illinois Electric Settlement Agreement (5 cents per share).

The cents per share information presented above is based on average shares outstanding in 2008.

For additional details regarding the Ameren Companies results of operations, including explanations of Margins, Other Operations and Maintenance Expenses, Goodwill and Other Impairment Losses, Depreciation and Amortization, Taxes Other Than Income Taxes, Interest Charges, and Income Taxes, see the major headings below.

Because it is a holding company, Ameren s net income and cash flows are primarily generated by its principal subsidiaries: UE, AIC and Genco. The following table presents the contribution by Ameren s principal subsidiaries to Ameren s consolidated net income for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
Net income (loss):			
UE[a]	**$ 364**	$ 259	$ 245
AIC[b]	**248**	241	87
Genco	**(39)**	160	286
Other[c]	**(434)**	(48)	(13)
Net income attributable to Ameren Corporation	**$ 139**	$ 612	$ 605

(a) Includes earnings from a 40% interest in EEI through February 29, 2008.
(b) Includes AERG for all periods prior to October 1, 2010, when AIC distributed AERG stock to Ameren.
(c) Includes earnings from other merchant generation operations, as well as corporate general and administrative expenses, and intercompany eliminations. During 2010, Ameren Corporation, parent, and other nonregistrant subsidiaries recorded a $419 million impairment charge related to goodwill, long-lived assets, and intangible assets in the Merchant Generation segment.

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Below is a table of income statement components by segment for the years ended December 31, 2010, 2009, and 2008:

2010	Ameren Missouri	Ameren Illinois	Merchant Generation	Other / Intersegment Eliminations	Total
Electric margins	**$ 2,233**	**$ 1,096**	**$ 780**	**$ (17)**	**$ 4,092**
Natural gas margins	**75**	**375**	**-**	**(2)**	**448**
Other revenues	**1**	**-**	**-**	**(1)**	**-**
Other operations and maintenance	**(931)**	**(635)**	**(287)**	**32**	**(1,821)**
Goodwill and other impairment losses	**-**	**-**	**(589)**	**-**	**(589)**
Depreciation and amortization	**(382)**	**(210)**	**(146)**	**(27)**	**(765)**
Taxes other than income taxes	**(285)**	**(128)**	**(26)**	**(10)**	**(449)**
Other income and (expenses)	**70**	**(6)**	**1**	**(8)**	**57**
Interest charges	**(213)**	**(143)**	**(133)**	**(8)**	**(497)**
Income (taxes) benefit	**(199)**	**(137)**	**(6)**	**17**	**(325)**
Net income (loss)	**369**	**212**	**(406)**	**(24)**	**151**
Noncontrolling interest and preferred dividends	**(5)**	**(4)**	**(3)**	**-**	**(12)**
Net income (loss) attributable to Ameren Corporation	**$ 364**	**$ 208**	**$ (409)**	**$ (24)**	**$ 139**
2009					
Electric margins	$ 1,983	$ 917	$ 1,012	$ (22)	$ 3,890
Natural gas margins	73	373	-	-	446
Other revenues	4	4	-	(8)	-
Other operations and maintenance	(880)	(590)	(333)	35	(1,768)
Goodwill and other impairment losses	-	-	(7)	-	(7)
Depreciation and amortization	(357)	(216)	(126)	(26)	(725)
Taxes other than income taxes	(257)	(125)	(28)	(10)	(420)
Other income and (expenses)	56	2	1	(11)	48
Interest charges	(229)	(153)	(119)	(7)	(508)
Income (taxes) benefit	(128)	(79)	(151)	26	(332)
Net income (loss)	265	133	249	(23)	624
Noncontrolling interest and preferred dividends	(6)	(6)	(2)	2	(12)
Net income (loss) attributable to Ameren Corporation	$ 259	$ 127	$ 247	$ (21)	$ 612
2008					
Electric margins	$ 1,924	$ 837	$ 1,188	$ (47)	$ 3,902
Natural gas margins	78	351	-	(4)	425
Other revenues	3	1	-	(4)	-
Other operations and maintenance	(922)	(653)	(342)	55	(1,862)
Goodwill and other impairment losses	-	-	(14)	-	(14)
Depreciation and amortization	(329)	(219)	(109)	(28)	(685)
Taxes other than income taxes	(240)	(126)	(26)	(12)	(404)
Other income and (expenses)	53	11	-	(15)	49
Interest charges	(193)	(145)	(99)	(3)	(440)
Income (taxes) benefit	(134)	(16)	(217)	40	(327)
Net income (loss)	240	41	381	(18)	644
Noncontrolling interest and preferred dividends	(6)	(6)	(29)	2	(39)
Net income (loss) attributable to Ameren Corporation	$ 234	$ 35	$ 352	$ (16)	$ 605

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Margins

The following table presents the favorable (unfavorable) variations in the registrants electric and natural gas margins from the previous year. Electric margins are defined as electric revenues less fuel and purchased power costs. Natural gas margins are defined as gas revenues less gas purchased for resale. The table covers the years ended December 31, 2010, 2009, and 2008. We consider electric and natural gas margins useful measures to analyze the change in profitability of our electric and natural gas operations between periods. We have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, these margins may not be a presentation defined under GAAP, and they may not be comparable to other companies presentations or more useful than the GAAP information we provide elsewhere in this report.

2010 versus 2009	**Ameren[(a)]**	**UE**	**AIC**	**Genco**
Electric revenue change:				
Effect of weather (estimate)[(b)]	$ 174	$ 134	$ 40	$ -
Regulated rates:				
Changes in base rates	203	162	41	-
Noranda sales	54	54	-	-
Illinois pass-through power supply costs	220	-	(83)	-
Energy efficiency programs and environmental remediation cost riders	29	-	29	-
Bad debt rider	14	-	14	-
Transmission services	49	7	42	-
Recovery of FAC net under-recovery	60	60	-	-
Sales price changes, including hedge effect	(243)	-	-	(81)
Off-system revenues	(102)	(102)	-	-
2007 Illinois Electric Settlement Agreement, net of reimbursement	23	-	10	10
Net unrealized MTM gains (losses)	49	-	-	(1)
Sales (excluding impact of abnormal weather) and other	51	15	3	50
Total electric revenue change	$ 581	$ 330	$ 96	$ (22)
Fuel and purchased power change:				
Fuel:				
Production volume and other	$ (138)	$ (91)	$ -	$ (38)
FAC net under-recovery	138	138	-	-
Recovery of FAC net under-recovery	(60)	(60)	-	-
Net unrealized MTM losses	(51)	(29)	-	(18)
Price Merchant Generation	(71)	-	-	(51)
Purchased power	23	(38)	-	11
Illinois pass-through power supply costs	(220)	-	83	-
Total fuel and purchased power change	$ (379)	$ (80)	$ 83	$ (96)
Net change in electric margins	**$ 202**	**$ 250**	**$ 179**	**$ (118)**
Natural gas margins change:				
Effect of weather (estimate)[(b)]	$ 1	$ -	$ 1	$ -
Bad debt rider	15	-	15	-
Rate decrease	(11)	-	(11)	-
Energy efficiency programs and environmental remediation cost riders	1	-	1	-
Net unrealized MTM losses	(6)	-	(6)	-
Sales (excluding impact of abnormal weather) and other	2	2	2	-
Net change in natural gas margins	**$ 2**	**$ 2**	**$ 2**	**$ -**

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2009 versus 2008	Ameren[a]	UE	AIC	Genco
Electric revenue change:				
Effect of weather (estimate)[b]	$ (47)	$ (33)	$ (14)	$ -
Regulated rates:				
Changes in base rates	229	141	88	-
Noranda sales	(50)	(50)	-	-
Illinois pass-through power supply costs	(338)	-	(338)	-
Energy efficiency programs and environmental remediation cost riders	11	-	11	-
Sales price changes, including hedge effect	57	-	-	(48)
Off-system revenues	(89)	(89)	-	-
2007 Illinois Electric Settlement Agreement	15	-	5	7
Net unrealized MTM (losses) gains	(110)	-	-	2
Sales (excluding impact of abnormal weather) and other	(125)	(25)	(29)	(235)
Total electric revenue change	$ (447)	$ (56)	$ (277)	$ (274)
Fuel and purchased power change:				
Fuel:				
Production volume and other	$ 88	$ (17)	$ 1	$ 93
FAC net under-recovery, net of collections	38	38	-	-
Net unrealized MTM gains	118	58	-	48
Price Merchant Generation	(83)	-	-	(80)
Coal contract settlement	(27)	-	-	(27)
Purchased power	(25)	48	18	25
Illinois pass-through power supply costs	338	-	338	-
FERC-ordered MISO resettlements	(12)	(12)	-	-
Total fuel and purchased power change	$ 435	$ 115	$ 357	$ 59
Net change in electric margins	**$ (12)**	**$ 59**	**$ 80**	**$ (215)**
Natural gas margins change:				
Effect of weather (estimate)[b]	$ (7)	$ (1)	$ (6)	$ -
Changes in base rates	34	-	34	-
Absence of capitalization of nonrecoverable gas costs	(5)	-	(5)	-
Energy efficiency programs and environmental remediation cost riders	4	-	4	-
Net unrealized 2008 MTM losses	12	-	12	-
Sales (excluding impact of abnormal weather) and other	(17)	(4)	(17)	-
Net change in natural gas margins	**$ 21**	**$ (5)**	**$ 22**	**$ -**

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Represents the estimated margin impact resulting from the effects of changes in cooling and heating degree-days on electric and natural gas demand compared to the prior year based on temperature readings from the National Oceanic and Atmospheric Administration.

2010 versus 2009

Ameren Corporation

Ameren s electric margins increased by $202 million, or 5%, in 2010 compared with 2009. The following items had a favorable impact on Ameren s electric margins:

- Favorable weather conditions, as evidenced by a 52% increase in cooling degree-days, which increased revenues by $174 million.
- Higher electric rates at UE, effective March 1, 2009, and June 21, 2010, which increased margins by $162 million.
- Increased UE sales to Noranda in 2010 as its smelter plant gradually returned to full capacity in March 2010 after a January 2009 severe storm significantly reduced the plant s capacity, which increased revenues by $54 million.
- Higher transmission revenues primarily associated with higher FERC-regulated transmission rates. Higher rates were due, in part, to a significant increase in transmission assets placed into service at AIC during 2009, higher equity levels as a result of Ameren s capital contributions to AIC in 2009, and mild 2009 weather, which increased margins by $49 million.
- Higher electric rates at AIC, effective in early May 2010, as well as the adjustment of residential electric delivery rates effective October 1, 2009, to recover the full increase of IP s 2008 ICC rate order, which increased margins by $41 million.

Net unrealized MTM activity at the Merchant Generation segment (primarily at Marketing Company), primarily related to nonqualifying power hedges, which increased margins by $49 million.

Recovery of energy efficiency program costs and environmental remediation costs through Illinois rate-adjustment mechanisms at AIC, which increased margins by $29 million. See Operations and Maintenance in this section for information on a related offsetting increase in energy efficiency program costs and environmental remediation costs.

Excluding the impact of UE s increased sales to Noranda and the estimated impact of abnormal weather, rate-regulated retail sales volumes increased

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by 3% largely due to improved economic conditions, which increased margins by $25 million.
A reduction in the impact of the 2007 Illinois Electric Settlement Agreement, which increased margins by $23 million.
Recovery of prior years bad debt expense through the Illinois bad debt rider at AIC effective March 2010, which increased revenues by $14 million. See Operations and Maintenance in this section for additional information on a related offsetting increase in bad debt expense.

The following items had an unfavorable impact on Ameren s electric margins for 2010 compared with 2009:

Reductions in higher-margin sales at the Merchant Generation segment resulting from the expiration of the 2006 auction power supply agreements on May 31, 2010, and lower market prices resulting in fewer opportunities for economic power sales, which decreased margins by $243 million.
A $93 million increase in UE s net base fuel expense, which is substantially recovered from its customers, through higher sales volume associated with favorable weather in 2010 compared with 2009 and higher rates. Net base fuel expense is the sum of fuel production volume and other ($91 million), purchased power ($38 million), and off-system sales ($102 million) offset by the FAC net under-recovery ($138 million).
14% higher fuel prices in the Merchant Generation segment primarily due to higher commodity and transportation costs associated with new supply contracts, which decreased margins $71 million.
In the first quarter of 2009, the reversal of previously unrealized losses related to regulatory assets resulted in the recognition of a $29 million net MTM gain on energy and fuel-related contracts at UE. After the implementation of UE s FAC on March 1, 2009, UE s net MTM gains or losses no longer impact electric margins. Net unrealized MTM activity at the Merchant Generation segment on fuel-related transactions, primarily associated with financial instruments that were acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts, which reduced margins by $20 million.

Ameren s Illinois pass-through power supply costs reflect lower power prices and the expiration of intercompany power supply agreements between AIC and Marketing Company. AIC purchased power from Marketing Company from January 1, 2007, through May 31, 2010, under power supply agreements entered into following a 2006 Illinois power procurement auction. The purchases and sales under these agreements were eliminated in consolidation for Ameren s financial statements. Subsequent to the expiration of these agreements in May 2010, Marketing Company s power sales and AIC s power purchases have primarily been made with nonaffiliated parties. As a result, Ameren s consolidated revenues increased by a net $220 million in 2010 compared with

2009. These revenues were offset by a corresponding $220 million net increase in purchased power costs.

Ameren s natural gas margins increased $2 million, or less than 1%, in 2010 compared with 2009. The following items had a favorable impact on Ameren s natural gas margins:

Recovery of prior years bad debt expense through the Illinois bad debt rider at AIC effective March 2010, which increased revenues by $15 million. See Operations and Maintenance in this section for additional information on a related offsetting increase in bad debt expense.
Favorable higher-margin customer mix that was mitigated by a 2% decrease in sales volumes, which increased margins by $2 million.

The following items had an unfavorable impact on Ameren s natural gas margins in 2010 compared with 2009:

Lower natural gas rates effective early May 2010 at AIC, which reduced margins by $11 million.
The absence of net unrealized MTM gains in 2010 of $6 million on natural gas swaps.

Ameren Missouri (UE)

UE has a FAC cost recovery mechanism that allows UE to recover, through customer rates, 95% of changes in fuel-production volume and other costs and purchased power costs, net of off-system revenues, including MISO costs and revenues, greater or less than the amount set in base rates, without a traditional rate proceeding.

UE s electric margins increased $250 million, or 13%, in 2010 compared with 2009. The following items had a favorable impact on UE s electric margins:

Higher electric rates, effective March 1, 2009, and June 21, 2010, which increased margins $162 million.
Favorable weather conditions, as evidenced by a 44% increase in cooling degree-days, which increased revenues by $134 million.
Increased sales to Noranda in 2010 as its smelter plant gradually returned to full capacity in March 2010 after a January 2009 severe storm significantly reduced the plant s capacity, which increased electric revenues by $54 million.
Taum Sauk s return to service. Although Taum Sauk was not available to generate electricity for off-system revenues during 2009, UE had included $19 million in the calculation of the FAC as if Taum Sauk had generated off-system revenues. Upon Taum Sauk s return to service in April 2010, UE s margins have increased since the adjustment factor was eliminated from the FAC calculation, which increased margins by $12 million.
Excluding the impact of increased sales to Noranda and the estimated impact of abnormal weather, rate-regulated retail sales volumes increased by less than 1%, largely due to improved economic conditions, which increased margins by $9 million.

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The following items had an unfavorable effect on UE s electric margins in 2010 compared with 2009:

- A $93 million increase in net base fuel expense, which is substantially recovered from its customers, as a result of higher sales volume associated with favorable weather in 2010 compared with 2009 and higher rates. Net base fuel expense is the sum of fuel production volume and other ($91 million), purchased power ($38 million), and off-system sales ($102 million) offset by the FAC net under-recovery ($138 million).
- The reversal of previously unrealized losses to regulatory assets, which resulted in the recognition of a $29 million net MTM gain on energy and fuel-related contracts in the first quarter of 2009. This benefit did not reoccur in 2010. After the implementation of the FAC on March 1, 2009, net MTM gains or losses no longer affect electric margins. See Note 7 Derivative Financial Instruments under Part II, Item 8, of this report for additional information.

UE s natural gas margins increased by $2 million, or 3%, in 2010 compared with 2009 because of a 2% increase in sales volumes, largely due to improved economic conditions.

Ameren Illinois (AIC)

AIC has a cost recovery mechanism for power purchased on behalf of its customers. These pass-through power costs do not affect margins; however, the electric revenues and offsetting purchased power costs may fluctuate, primarily because of customer switching and usage. See below for explanations of electric and natural gas margin variances for the Ameren Illinois segment.

AIC s electric margins increased by $179 million, or 20%, in 2010 compared with 2009. The following items had a favorable impact on electric margins:

- Higher transmission revenues primarily associated with higher FERC-regulated transmission rates. Higher rates were due, in part, to an increase in transmission assets placed into service during 2009, higher equity levels resulting from Ameren s capital contributions to IP in 2009, and mild 2009 weather, which increased margins by $42 million.
- Higher delivery service rates, effective in early May 2010, as well as the adjustment of residential electric delivery rates effective October 1, 2009, at IP to recover the full increase of the 2008 ICC rate order, which increased margins by $41 million.
- Favorable weather conditions, as evidenced by a 65% increase in cooling degree-days, which increased revenues by $40 million.
- Recovery of energy efficiency program costs and environmental remediation costs through Illinois rate-adjustment mechanisms, which increased margins by $29 million. See Operations and Maintenance in this section for information on a related offsetting increase in energy efficiency program costs and environmental remediation costs.
- Recovery of prior years bad debt expense under the Illinois bad debt rider effective March 2010, which increased revenues by $14 million. See Operations and Maintenance in this section for additional information on a related offsetting increase in bad debt expense.
- A reduction in the impact of the 2007 Illinois Electric Settlement Agreement, which increased margins by $10 million.

AIC s natural gas margins increased by $2 million, or 1%, in 2010 compared with 2009. The following items had a favorable impact on natural gas margins:

- Recovery of prior years bad debt expense under the Illinois bad debt rider, effective March 2010, which increased revenues by $15 million. See Operations and Maintenance in this section for additional information on a related offsetting increase in bad debt expense.
- A higher-margin customer mix that was mitigated by a 3% decrease in sales volumes, which increased margins by $2 million.

The following items had an unfavorable impact on AIC s natural gas margins in 2010 compared with 2009:

- Lower natural gas rates effective early May 2010, which reduced margins by $11 million.
- The absence of net unrealized MTM gains in 2010 of $6 million on natural gas swaps, as occurred in 2009.

Merchant Generation

Merchant Generation s electric margins decreased by $232 million, or 23%, in 2010 compared with 2009. See below for explanations of electric margin variances for the Merchant Generation segment.

Genco

Genco s electric margins decreased by $118 million, or 18%, in 2010 compared with 2009. The following items had an unfavorable impact on electric margins:

- Lower revenues allocated to Genco under its power supply agreement (Genco PSA) with Marketing Company. There was a smaller pool of money to allocate because of reductions in higher-margin sales, resulting from the expiration of older long-term contracts and because of lower market prices. The lower market prices associated with the Genco PSA were mitigated by higher market prices associated with EEI s power supply agreement with Marketing Company (EEI PSA). The net impact of lower market prices under both power supply agreements reduced electric revenues by $81 million. In accordance with the Genco PSA, Genco was also allocated a lower percentage of revenues from the pool because of lower reimbursable expenses and lower generation relative to AERG.
- 14% higher fuel prices in 2010 compared with 2009, primarily due to higher commodity and transportation costs associated with new supply contracts, which reduced margins by $51 million.

- Net unrealized MTM activity on fuel-related transactions primarily associated with financial instruments acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts, which reduced margins by $18 million.

The following items had a favorable impact on Genco s electric margins in 2010 compared with 2009:

- A reduction in the impact of the 2007 Illinois Electric Settlement Agreement, which increased margins by $10 million.
- Increased power plant utilization, primarily due to more economic sales opportunities and a reduction in transmission constraints, which previously limited the period in which power could be sold. In addition, one of Genco s coal-fired power plants experienced a transformer fire in September 2009, which put two units out of service for a period of time in 2009. The higher production volume contributed to the $50 million increase in electric revenues, which was mitigated by higher production volume costs of $38 million. Genco s baseload coal-fired generating plants average capacity factor increased to 71% in 2010, compared with 67% in 2009, and Genco s equivalent availability factor increased to 88% in 2010, compared with 82% in 2009.

Other Merchant Generation

Electric margins from Ameren s other Merchant Generation operations, primarily AERG and Marketing Company, decreased by $114 million, or 32%, in 2010. Other Merchant Generation electric margins were unfavorably affected, compared with 2009, by:

- Lower revenues allocated to AERG under its power supply agreement (AERG PSA) with Marketing Company. There was a smaller pool of money to allocate because of reductions in higher-margin sales resulting from the expiration of older long-term contracts and because of lower market prices. These items reduced electric margins by $109 million. However, in accordance with the AERG PSA, AERG was allocated a greater percentage of revenues from the pool because of higher reimbursable expenses and higher generation relative to Genco.
- 19% higher fuel prices at AERG in 2010 compared with 2009, primarily due to higher commodity and transportation costs associated with new supply contracts, which reduced margins by $20 million.

The following items had a favorable impact on the electric margins of other Merchant Generation operations for 2010 compared with 2009:

- Net unrealized MTM activity at Marketing Company improved margins by $50 million primarily because of nonqualifying power hedges.
- A reduction in the impact of the 2007 Illinois Electric Settlement Agreement at AERG, which increased margins by $4 million.
- Increased power plant utilization at AERG, primarily due to more opportunities for economic sales and a reduction in plant outages. The higher production volume increased electric revenues by $37 million, which was partially offset by higher production volume costs of $16 million. AERG s baseload coal-fired generating plants average capacity factor increased to 75% in 2010, compared with 69% in 2009, while AERG s equivalent availability factor increased to 85% in 2010, compared with 78% in 2009.

2009 versus 2008

Ameren

Ameren s electric margins decreased by $12 million, or less than 1%, in 2009 compared with 2008. The following items had an unfavorable impact on Ameren s electric margins:

- Net unrealized MTM activity in the Merchant Generation segment decreased margins by $110 million (Marketing Company net loss of $112 million and Genco net gain of $2 million), primarily related to nonqualifying power hedges.
- Higher fuel expense at Genco as a result of its June 2008 agreement with a coal mine owner to receive a lump-sum payment of $60 million for the early termination of a coal supply contract. This payment compensated Genco, in total, for higher fuel costs it incurred throughout 2008 ($33 million) and 2009 ($27 million). Because the entire settlement was recorded in earnings in 2008, Ameren s recorded earnings in 2009 were lower than they otherwise would have been.
- Excluding the impact of the June 2008 settlement agreement, 5% higher fuel prices in the Merchant Generation segment.
- Reduced sales by UE to Noranda, due to an extended severe storm-related outage, which lowered electric revenues by $50 million in 2009.
- Unfavorable weather conditions, as evidenced by a 7% reduction in cooling degree-days, which decreased revenues by $47 million.

Excluding the impact of UE s reduced sales to Noranda and the estimated impact of abnormal weather, rate-regulated retail sales volumes decreased by 4% in Ameren s rate-regulated utilities, largely a result of the economic slowdown, which decreased margins by $40 million.
Higher net fuel expense at UE of $20 million resulting from lower off-system revenues and higher production volume and other, offset in part by lower purchased power and FAC under-recovery.
Decreased power plant utilization in the Merchant Generation segment, primarily because of lower market prices, which resulted in fewer opportunities for economic sales, and transmission congestion, which limited the period when power could be sold. The lower production volume contributed to the $125 million decrease in electric revenues, which was mitigated by

lower production volume costs of $88 million. Merchant Generation s baseload, coal-fired generating plants equivalent availability factors were 81% in 2009, compared with 85% in 2008. The average capacity factor was 66% in 2009, compared with 76% in 2008.

The following items had a favorable impact on Ameren s electric margins for 2009 compared with 2008:

- Higher electric rates at UE, effective March 1, 2009, which increased margins by $141 million, and higher rates at AIC, effective October 1, 2008, which increased margins by $88 million.
- Net unrealized MTM activity at UE improved margins by $58 million on energy and fuel-related transactions. During 2009, UE reversed and deferred as regulatory assets previously recorded net MTM losses of $42 million on energy and fuel-related transactions when these costs became probable of recovery because of the FAC.
- Net unrealized MTM activity improved margins by $55 million at the Merchant Generation segment (Genco $48 million, AERG $7 million). These were primarily associated with financial instruments acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts.
- The repricing of wholesale and retail electric power supply agreements and financial swaps that settled at higher margins at Merchant Generation.
- A $32 million increase in wholesale sales margins at UE because of additional customers and higher-priced wholesale sales contracts. Power was available for sale to wholesale customers as a result of reduced native load demand.
- Recovery of energy efficiency program costs and environmental remediation costs through Illinois rate-adjustment mechanisms at AIC, which increased margins by $11 million. See Operations and Maintenance in this section for information on a related offsetting increase in energy efficiency program costs and environmental remediation costs.
- A $15 million reduction in the impact of the 2007 Illinois Electric Settlement Agreement.
- Higher Callaway nuclear plant availability due to the absence of a 30-day planned maintenance outage, which occurred in 2008.

Ameren s natural gas margins increased by $21 million, or 5%, in 2009 compared with 2008. The following items had a favorable impact on Ameren s natural gas margins:

- AIC s net natural gas delivery service rate increase, effective October 1, 2008, which increased margins by $34 million.
- The absence of net unrealized MTM losses at AIC on natural gas swaps that improved margins by $12 million in 2009.
- Recovery of energy efficiency program costs and environmental remediation costs through Illinois rate-adjustment mechanisms at AIC, which increased margins by $4 million. See Operations and Maintenance in this section for information on a related offsetting increase in energy efficiency program costs and environmental remediation costs.

The following items had an unfavorable impact on Ameren s natural gas margins in 2009 compared with 2008:

- 7% lower sales volumes, excluding the estimated impact of abnormal weather, largely a result of the economic slowdown, and lower realized prices related to a contract with a large industrial customer in 2009, which decreased margins by $17 million.
- Unfavorable weather conditions, as evidenced by an 8% reduction in heating degree-days, which decreased margins by $7 million.
- The absence of the capitalization of nonrecoverable purchased gas costs in accordance with the September 2008 ICC gas rate order, which resulted in a one-time increase in margins of $5 million in 2008.

Ameren Missouri (UE)

UE has a FAC cost recovery mechanism that allows UE to recover, through customer rates, 95% of changes in fuel-production volume and other costs and purchased power costs, net of off-system revenues, including MISO costs and revenues, greater or less than the amount set in base rates, without a traditional rate proceeding.

UE s electric margins increased $59 million, or 3%, in 2009 compared with 2008. The following items had a favorable impact on UE s electric margins:

- Higher electric rates, effective March 1, 2009, which increased margins by $141 million.

Net unrealized MTM activity on energy and fuel-related transactions that improved margins by $58 million. During 2009, UE reversed and deferred as regulatory assets previously recorded net MTM losses of $42 million on energy and fuel-related transactions when these costs became probable of recovery because of the FAC.

A $32 million increase in wholesale sales margins due to additional customers and higher-priced wholesale sales contracts. Power was available for sale to wholesale customers as a result of reduced native load demand.

Higher Callaway nuclear plant availability due to the absence of a 30-day planned maintenance outage, which occurred in 2008.

The following items had an unfavorable impact on UE s electric margins in 2009 compared with 2008:

Reduced sales to Noranda, due to an extended severe storm-related outage, which lowered electric revenues by $50 million.

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- Unfavorable weather conditions, as indicated by a 13% reduction in cooling degree-days during the third quarter of 2009, which is UE s peak cooling period, and a mild winter, which decreased revenues by $33 million.
- Excluding the impact of reduced sales to Noranda and the estimated impact of abnormal weather, rate-regulated retail sales volumes decreased by 2%, largely a result of the economic slowdown, which decreased margins by $25 million.
- A $20 million increase in net fuel expense resulting from lower off-system revenues and higher production volume and other, offset in part by lower purchased power and FAC under-recovery.
- The absence in 2009 of the benefits from a MoPSC order that directed the recording in 2008 of a regulatory asset related to previously incurred costs for a 2007 FERC order, which decreased margins by $12 million.

UE s natural gas margins decreased by $5 million, or 6%, in 2009 compared with 2008, primarily because of an 8% decrease in sales volumes in 2009.

Ameren Illinois (AIC)

AIC has a cost recovery mechanism for power purchased on behalf of its customers. These pass-through power costs do not affect margins; however, the electric revenues and offsetting purchased power costs may fluctuate, primarily because of customer switching and usage. See below for explanations of electric and natural gas margin variances for the Ameren Illinois segment.

AIC s electric margins increased by $80 million, or 10%, in 2009 compared with 2008. The following items had a favorable impact on electric margins:

- Higher electric delivery service rates, effective October 1, 2008, which increased margins by $88 million.
- Recovery of energy efficiency program costs and environmental remediation costs through Illinois rate-adjustment mechanisms, which increased margins by $11 million. See Operations and Maintenance in this section for information on a related offsetting increase in energy efficiency program costs and environmental remediation costs.
- A $5 million reduction in the impact of the 2007 Illinois Electric Settlement Agreement.

AIC s electric margins were unfavorably affected in 2009 compared with 2008 by the following items:

- 5% lower sales volumes excluding the estimated impact of abnormal weather, primarily in the lower-margin industrial customer sector, largely as a result of the economic slowdown, which decreased margins by $15 million.
- Unfavorable weather conditions, as evidenced by a 13% reduction in cooling degree-days, which decreased revenues by $14 million.

AIC s natural gas margins increased by $22 million, or 6%, in 2009 compared with 2008. The following items had a favorable impact on natural gas margins:

- Higher net natural gas delivery service rates, effective October 1, 2008, which increased margins by $34 million.
- The absence of net unrealized MTM losses on natural gas swaps that improved margins by $12 million in 2009.
- Recovery of energy efficiency program costs and environmental remediation costs through Illinois rate-adjustment mechanisms, which increased margins by $4 million. See Operations and Maintenance in this section for information on a related offsetting increase in energy efficiency program costs and environmental remediation costs.

The following items had an unfavorable impact on AIC s natural gas margins in 2009 compared with 2008:

- 6% lower sales volumes excluding the estimated impact of abnormal weather, largely a result of the economic slowdown, and lower realized prices related to a contract with a large industrial customer in 2009, which decreased margins by $13 million.
- Unfavorable weather conditions, as evidenced by a 7% reduction in heating degree-days, which decreased margins by $6 million.
- The absence of the capitalization of nonrecoverable purchased gas costs in accordance with the September 2008 ICC gas rate order, which resulted in a one-time increase in margins of $5 million in 2008.

Merchant Generation

Merchant Generation s electric margins decreased by $176 million, or 15%, in 2009 compared with 2008. See below for explanations of electric margin variances for the Merchant Generation segment.

Genco

Genco s electric margins decreased by $215 million, or 25%, in 2009 compared with 2008. The following items had an unfavorable impact on electric margins:

Decreased power plant utilization, primarily due to lower market prices, which resulted in fewer opportunities for economic sales, and transmission congestion, which limited the period when power could be sold. In addition, one of Genco s coal-fired power plants experienced a transformer fire in September 2009, which put two units out of service for a time. The lower production volume contributed to the $235 million decrease in electric revenues, which was mitigated by lower production volume costs of $93 million. This contributed to a reduction in Genco s baseload coal-fired generating plants equivalent availability factor to 82% in 2009, compared with 88% in 2008. Genco s average capacity factor also decreased to 67% in 2009, compared with 80% in 2008.

Lower revenues associated with EEI s power supply agreement with Marketing Company driven primarily by lower market prices, which decreased revenues by $191 million.

Lower revenues allocated to Genco under the Genco PSA because of lower reimbursable expenses and lower generation relative to AERG in accordance with the Genco PSA, partially offset by financial swaps settling at higher margins and new higher-priced wholesale and retail electric power supply agreements. These higher sales prices increased electric revenues by $143 million.

Higher fuel expense as a result of Genco s June 2008 agreement with a coal mine owner to receive a lump-sum payment of $60 million for the early termination of a coal supply contract. This payment compensated Genco, in total, for higher fuel costs it incurred throughout 2008 ($33 million) and 2009 ($27 million). Because the entire settlement was recorded in earnings in 2008, Genco s recorded earnings in 2009 were lower than they otherwise would have been.

Excluding the impact of the June 2008 settlement agreement, 8% higher fuel prices.

Genco s electric margins were favorably affected in 2009 compared with 2008 by the following items:

Net unrealized MTM activity on fuel-related transactions improved margins by $48 million. These were primarily associated with financial instruments acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts.

A $7 million reduction in the impact of the 2007 Illinois Electric Settlement Agreement.

Other Merchant Generation

Electric margins from Ameren s other Merchant Generation operations, primarily AERG and Marketing Company, increased by $39 million, or 13%, in 2009. Other Merchant Generation electric margins were favorably affected, compared with 2008, by:

Higher revenues allocated to AERG under the AERG PSA because of higher reimbursable expenses and higher generation relative to Genco in accordance with the AERG PSA. AERG s baseload coal-fired generating plants equivalent availability and average capacity factors were comparable to 2008. Financial swaps also settled at higher margins, and new higher-priced wholesale and retail electric power supply agreements increased revenues. These items increased electric margins by $77 million.

Net unrealized MTM activity at AERG on fuel-related transactions increased margins by $7 million. These were primarily associated with financial instruments that were acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts.

Lower oil consumption at AERG because of fewer plant startups and lower oil prices in 2009, which reduced costs by $6 million.

A $3 million reduction in the impact of the 2007 Illinois Electric Settlement Agreement.

Other Merchant Generation electric margins were reduced by $112 million in 2009 compared with 2008 by net unrealized MTM activity at Marketing Company. These were primarily associated with financial instruments that related to nonqualifying power hedges.

Other Operations and Maintenance Expenses

2010 versus 2009

Ameren Corporation

Other operations and maintenance expenses increased $53 million in 2010 compared with 2009.

The following items increased other operations and maintenance expenses between periods:

Increased plant maintenance and labor costs of $39 million associated with a refueling and maintenance outage at the Callaway nuclear plant and an increase of $16 million for other scheduled coal-fired plant outages, the installation of scrubbers at UE s Sioux plant, and other maintenance work. There was no Callaway nuclear plant refueling and maintenance outage in 2009.

A $46 million increase in bad debt expense. The July 2009 capitalization and recovery of prior years bad debt expense under the Illinois bad debt rate
adjustment mechanism (net of a related donation for customer assistance programs) reduced bad debt expense in 2009. Additionally, bad debt expense increased in 2010, because of amortization of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment

mechanism in 2009. Amortization expense associated with these regulatory assets was offset by increased revenues through collection from customers, with no overall impact on net income.

Increased AIC energy efficiency program costs and environmental remediation costs of $30 million. Energy efficiency program costs are allowed to be recovered from customers under the 2007 Illinois Electric Settlement Agreement; environmental remediation costs associated with MGPs are recoverable from customers through Illinois environmental adjustment rate riders. Accordingly, these costs are offset by increased revenues, with no overall impact on net income. See Note 2 Rate and Regulatory Matters and Note 15 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for additional information.

An unfavorable change of $7 million in unrealized net MTM adjustments between periods, resulting from changes in the market value of investments used to support Ameren s deferred compensation plans.

The following items reduced other operations and maintenance expenses between periods:

The absence in 2010 of major storms, such as had occurred in 2009, which resulted in a $27 million

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reduction in other operations and maintenance expenses.

Severance costs of $17 million for employee separation programs recognized in 2009, as compared with $4 million in 2010.

A May 2010 MoPSC electric rate order, which resulted in UE recording regulatory assets in 2010 related to employee severance costs and storm costs incurred in 2009, which decreased expenses by $11 million.

A reduction in labor costs of $10 million, primarily because of staff reductions.

Items that unfavorably affected Ameren in 2009 that did not recur in 2010: a $5 million penalty incurred for the termination of a heavy forgings contract associated with efforts to build a new nuclear unit at UE s Callaway nuclear plant and a $5 million write-off of Ameren s investment in a supply acquisition partnership.

A gain on the sale of property interests at Genco recognized in 2010.

Variations in other operations and maintenance expenses in Ameren s business segments and for the Ameren Companies between 2010 and 2009 were as follows:

Ameren Missouri (UE)

Other operations and maintenance expenses increased $51 million in 2010. Plant maintenance and labor costs increased $39 million as a result of the Callaway nuclear plant refueling and maintenance outage and $34 million for other scheduled coal-fired plant outages, the installation of scrubbers at UE s Sioux plant, and other maintenance work and plant-related costs. Additionally, other operations and maintenance expenses increased because of an unfavorable change of $4 million in unrealized net MTM adjustments between periods resulting from changes in the market value of investments used to support Ameren s deferred compensation and higher bad debt expense of $5 million, primarily due to higher customer billings resulting from rate increases and weather conditions. Reducing the unfavorable impact of these items was the absence of major storms, such as had occurred in 2009, which resulted in a decrease in other operations and maintenance expenses of $13 million. Other operations and maintenance expenses were also reduced by the recording of regulatory assets in 2010 related to employee severance costs and storm costs incurred in 2009, and by the absence of severance costs for employee separation programs and the absence of the forgings contract penalty recognized in 2009, as discussed above.

Ameren Illinois (AIC)

Other operations and maintenance expenses increased $45 million in 2010, primarily because of a $40 million increase in bad debt expense resulting from the July 2009 capitalization and recovery of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism (net of a related donation for customer assistance programs), which decreased bad debt expense in 2009, and the

amortization in 2010 of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism in 2009. Energy efficiency program costs and environmental remediation costs increased by $30 million, as discussed above. Reducing the unfavorable impact of these items were the absence of major storms in 2010, as compared with storm costs of $16 million in 2009, and a $9 million reduction of employee benefit costs due, in part, to the absence of severance costs in 2010 such as AIC had incurred in 2009.

Merchant Generation

Other operations and maintenance expenses decreased $46 million in the Merchant Generation segment, primarily because of variations at Genco, as discussed below. Additionally, other operations and maintenance expenses decreased at AERG, primarily because of lower labor costs due to staff reductions, and reduced severance costs due to employee separation programs that were implemented in 2009.

Genco

Other operations and maintenance expenses decreased $35 million. Plant maintenance costs were lower by $16 million due to the retirement in 2009 of two generation units at Genco s Meredosia plant and other reductions in required maintenance work between years. Additionally,

other operations and maintenance costs were lower due to a $7 million reduction in employee benefit costs, due, in part, to reduced severance costs because of employee separation programs in 2009, a $5 million decline in labor costs resulting from staff reductions, and a property sale gain in 2010.

2009 versus 2008

Ameren Corporation

Other operations and maintenance expenses decreased $94 million in 2009 compared with 2008.

The following items reduced other operations and maintenance expenses between periods:

- Coal-fired plant maintenance costs were lower by $48 million, primarily because less work was undertaken as a result of cost-containment initiatives in response to weak economic conditions.
- Bad debt expense was lower by $44 million because of the impact of the implementation of the Illinois bad debt rate adjustment mechanism in 2009, as discussed above. Additionally, bad debt expense in 2008 was at an elevated level as a result of the transition to higher market-based rates at AIC.
- A favorable change of $37 million in unrealized net MTM adjustments between periods resulting from changes in the market value of investments used to support Ameren s deferred compensation plans.
- The absence of a Callaway nuclear plant refueling and maintenance outage in 2009, as compared with costs of $30 million in 2008.

The following items increased other operations and maintenance expenses between periods:

- In 2008, other operations and maintenance expenses were reduced by a MoPSC accounting order related to storm costs incurred in 2007, which resulted in UE s recording of a regulatory asset of $25 million; no similar item occurred in 2009.
- An increase of $24 million in labor costs due to wage increases and higher staff levels during most of 2009.
- The recognition of $17 million for employee severance costs in 2009.
- AIC s energy efficiency program costs and environmental remediation costs increased by $15 million.

Variations in other operations and maintenance expenses in Ameren s business segments and for the Ameren Companies between 2009 and 2008 were as follows:

Ameren Missouri (UE)

Other operations and maintenance expenses decreased $42 million in 2009. This was primarily because of a $32 million reduction in coal-fired plant maintenance costs due to reduced outages in 2009, as less work was undertaken as a result of cost containment initiatives in

response to weak economic conditions, and because of the absence of a Callaway nuclear plant refueling and maintenance outage in 2009, as compared with costs of $30 million in 2008. A favorable change of $19 million in unrealized net MTM adjustments between periods, which resulted from changes in the market value of investments used to support Ameren s deferred compensation plans, also resulted in decreased expenses between years. In addition to these items, employee benefit costs were lower by $14 million, primarily due to reduced expenses between years associated with the pension and postretirement benefit costs tracker allowed by the MoPSC, partially offset by increased expense due to changes in actuarial assumptions.

Reducing the benefit of these items was a $21 million increase in labor costs because of wage increases and higher staff levels during most of the year, the recognition of $8 million in employee severance costs in 2009, and the absence of the MoPSC storm cost accounting order of $25 million that occurred in 2008, as described above. In addition to these items, storm repair expenditures were higher in 2009 as a result of a severe ice storm at the beginning of the year.

Ameren Illinois (AIC)

Other operations and maintenance expenses decreased $63 million in 2009, primarily because of a $39 million reduction in bad debt expense, due to the impact of the Illinois bad debt rate adjustment mechanism (net of a related donation for customer assistance programs) and elevated levels of bad debt expense in 2008, as discussed above, and a favorable change in unrealized net MTM adjustments between periods resulting from changes in the

market value of investments used to support Ameren s deferred compensation plans. Partially offsetting these favorable items were higher energy efficiency program costs and environmental remediation costs.

Merchant Generation

Other operations and maintenance expenses decreased $9 million in 2009 in the Merchant Generation segment, primarily because of lower plant maintenance expenses at AERG. Genco s other operations and maintenance expenses were comparable between years, as higher employee severance costs were mitigated by lower plant maintenance costs. The reductions in plant maintenance costs at AERG and Genco were a result of cost containment initiatives in response to weak economic conditions.

Goodwill and Other Impairment Losses

In 2010, Ameren and Genco recognized noncash pretax impairment charges of $589 million (including Genco s impairment charges) and $170 million, respectively, related to goodwill, long-lived assets, and emission allowances within the Merchant Generation segment. In 2009, asset impairment charges of $7 million and $6 million were recorded at Ameren and Genco, respectively, primarily because of the termination of a rail line extension project at a subsidiary of Genco and to adjust the carrying value of an office building owned by Genco to its estimated fair value. In 2008, Ameren recognized asset impairment charges of $14 million to adjust the carrying value of AERG s Indian Trails and Sterling Avenue generation facilities to their fair values. See Note 17 Goodwill and Other Asset Impairments to our financial statements under Part II, Item 8, of this report for additional information.

Depreciation and Amortization

2010 versus 2009

Ameren Corporation

Ameren s depreciation and amortization expenses increased $40 million in 2010, as compared with 2009, because of items noted below at the Ameren Companies.

Variations in depreciation and amortization expenses in Ameren s business segments and for the Ameren Companies between 2010 and 2009 were as follows.

Ameren Missouri (UE)

Depreciation and amortization expenses increased $25 million in 2010, primarily because of capital additions and an increase in UE s annual depreciation rate due largely to the adoption of the life span depreciation methodology as a result of the 2010 MoPSC electric rate order.

Ameren Illinois (AIC)

Depreciation and amortization expenses decreased $6 million in 2010, primarily because of a reduction in amortization of regulatory assets. An ICC rate order in April

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2010 extended the amortization period of the IP integration-related regulatory asset. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for additional information.

Merchant Generation

Depreciation and amortization expenses increased $20 million in the Merchant Generation segment, primarily because of variations at Genco, as discussed below.

Genco

Depreciation and amortization expenses increased $17 million in 2010, primarily because of capital additions and increased depreciation rates resulting from depreciation studies performed in 2009.

2009 versus 2008

Ameren Corporation

Ameren s depreciation and amortization expenses increased $40 million in 2009, as compared with 2008, because of items noted below at the Ameren Companies.

Variations in depreciation and amortization expenses in Ameren s business segments and for the Ameren Companies between 2009 and 2008 were as follows.

Ameren Missouri (UE)

Depreciation and amortization expenses increased $28 million in 2009, primarily because of capital additions and amortization of regulatory assets that resulted from UE s electric rate order in 2009.

Ameren Illinois (AIC)

Depreciation and amortization expenses were comparable between years.

Merchant Generation

Depreciation and amortization expenses increased $17 million in the Merchant Generation segment, primarily because of capital additions at AERG and variations at Genco, as discussed below.

Genco

Genco s depreciation and amortization expenses increased $6 million, primarily because of expense recorded in 2009 for the retirement of two generation units at its Meredosia power plant.

Taxes Other Than Income Taxes

2010 versus 2009

Ameren Corporation

Taxes other than income taxes increased $29 million, because of items noted below at the Ameren Companies.

Variations in taxes other than income taxes in Ameren s business segments and for the Ameren Companies between 2010 and 2009 were as follows:

Ameren Missouri (UE)

Taxes other than income taxes increased $28 million, primarily because of higher gross receipts taxes as a result of increased sales, and because of increased property taxes due to higher assessed tax rates in Missouri.

Ameren Illinois (AIC)

Taxes other than income taxes were comparable between years.

Merchant Generation

Taxes other than income taxes were comparable between periods at the Merchant Generation segment and at Genco.

2009 versus 2008

Ameren Corporation

Ameren s taxes other than income taxes increased $16 million in 2009, primarily because of higher property and payroll taxes.

Variations in taxes other than income taxes in Ameren s business segments and for the Ameren Companies between 2009 and 2008 were as follows.

Ameren Missouri (UE)

Taxes other than income taxes increased $17 million in 2009, primarily because of higher property taxes.

Ameren Illinois (AIC)

Taxes other than income taxes were comparable between years.

Merchant Generation

Taxes other than income taxes were comparable between years at the Merchant Generation segment and at Genco.

Other Income and Expenses

2010 versus 2009

Ameren Corporation

Miscellaneous income, net of expenses, increased $9 million in 2010, because of items noted below at the Ameren Companies.

Variations in other income and expenses in Ameren s business segments and for the Ameren Companies between 2010 and 2009 were as follows:

Ameren Missouri (UE)

Miscellaneous income, net of expenses, increased $14 million in 2010, primarily because of higher allowance for equity funds used during construction associated with a project to install scrubbers at UE s Sioux plant, reduced, in part, by increased charitable contributions.

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Ameren Illinois (AIC)

AIC had net miscellaneous expense of $6 million in 2010, compared with net miscellaneous income of $2 million in 2009. Interest income decreased $5 million in 2010 compared with 2009 because CIPS note receivable from Genco matured on May 1, 2010.

Merchant Generation

Other income and expenses were comparable between years at the Merchant Generation segment and at Genco.

2009 versus 2008

Ameren Corporation

Other income and expenses were comparable in 2009 and 2008. Miscellaneous expenses decreased as expenses associated with energy efficiency and customer assistance programs under the 2007 Illinois Electric Settlement Agreement were lower in 2009. However, miscellaneous income declined because of reduced interest income, partially offset by increased allowance for equity funds used during construction.

Variations in other income and expenses in Ameren s business segments and for the Ameren Companies between 2009 and 2008 were as follows:

Ameren Missouri (UE)

Other income and expenses were comparable between years.

Ameren Illinois (AIC)

Miscellaneous income, net of expenses, decreased $9 million, primarily because of lower interest income. Reduced expenses associated with energy efficiency and customer assistance programs under the 2007 Illinois Electric Settlement Agreement mitigated this decrease.

Merchant Generation

Other income and expenses were comparable between years at the Merchant Generation segment and at Genco.

Interest Charges

2010 versus 2009

Ameren Corporation

Interest charges decreased $11 million in 2010, because of items noted below at the Ameren Companies. The decreases below were mitigated by additional interest charges resulting from the issuance of $425 million of senior notes by Ameren in May 2009.

Variations in interest charges in Ameren s business segments and for the Ameren Companies between 2010 and 2009 were as follows.

Ameren Missouri (UE)

Interest charges decreased $16 million in 2010. Interest charges were reduced by $10 million because of a

May 2010 MoPSC electric rate order, which resulted in UE recording a regulatory asset for recovery of bank credit facility fees incurred in 2009. Additionally, interest charges were reduced by an increase in allowance for borrowed funds used during construction associated with a project to install scrubbers at UE s Sioux plant. Partially reducing the above benefits was an increase in interest charges associated with the issuance of $350 million of senior secured notes in March 2009.

Ameren Illinois (AIC)

Interest charges decreased $10 million in 2010, primarily because of the maturity of $250 million of first mortgage bonds in June 2009.

Merchant Generation

Interest charges increased $14 million in 2010 in the Merchant Generation segment and $17 million at Genco, primarily because of the issuance of $250 million of senior unsecured notes at Genco in November 2009.

2009 versus 2008

Ameren Corporation

Ameren s interest charges increased $68 million in 2009, because of items noted below at the Ameren Companies and because of the issuance of $425 million of senior notes at Ameren in May 2009.

Variations in interest charges in Ameren s business segments and for the Ameren Companies between 2009 and 2008 were as follows:

Ameren Missouri (UE)

Interest charges increased $36 million in 2009, primarily because of the issuance of $350 million, $450 million, and $250 million of senior secured notes in March 2009, June 2008, and April 2008, respectively. The amortization of fees related to credit facilities entered into in the second quarter of 2009 also increased interest charges. Additionally, a reversal in interest charges previously accrued on uncertain tax positions due to favorable income tax settlements in 2008, with no similar item in 2009, had a negative impact on 2009. The maturity of $148 million of first mortgage bonds in May 2008 and refinancing of auction-rate environmental improvement revenue bonds in 2008, along with a reduction of short-term borrowings, mitigated the impact of the above items.

Ameren Illinois (AIC)

Interest charges increased $8 million in 2009, primarily because of the issuance of senior secured notes of $150 million at CILCO in December 2008 at a higher rate than the short-term borrowings it refinanced, and because of the amortization of fees related to a credit facility entered into in the second quarter of 2009. Increased interest charges resulting from the issuance at IP of senior secured notes of $400 million and $337 million in October 2008 and

April 2008, respectively, were mitigated as the proceeds of these issuances were used to refinance auction-rate pollution control revenue refunding bonds, which bore default rates ranging from 12% to 18%, and to reduce short-term borrowings.

Merchant Generation

Interest charges increased $20 million in 2009 in the Merchant Generation segment, primarily because of increased intercompany borrowings at AERG and amortization of fees related to new credit facilities entered into in the second quarter of 2009. Additionally, interest charges increased because of variations at Genco, as discussed below.

Genco

Interest charges increased $6 million in 2009, because of the issuance of $300 million of senior unsecured notes in April 2008.

Income Taxes

The following table presents effective income tax rates for the registrants and by segment for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Ameren	**68%** (a)	35%	34%
UE	**35**	33	36
AIC	**39**	37	28
Genco	**(b)**	38	37
Merchant Generation	**(c)**	38	36

(a) The effective tax rate was 36% for 2010, after excluding the impact of the goodwill impairment charge, which is not deductible for income tax purposes.
(b) The effective tax rate was 40% for 2010, after excluding the impact of the goodwill impairment charge, which is not deductible for income tax purposes.
(c) The effective tax rate was 30% for 2010, after excluding the impact of the goodwill impairment charge, which is not deductible for income tax purposes.

2010 versus 2009

Ameren Corporation

Ameren s effective tax rate in 2010 was higher than 2009, primarily due to the unfavorable impact of the goodwill impairment charge recognized in 2010 at Ameren. Goodwill impairment charges are not deductible for income tax purposes. In addition, legislation was enacted in the first quarter of 2010 that resulted in retiree health care costs no longer being deductible for tax purposes to the extent an employer s postretirement health care plan receives federal subsidies that provide retiree prescription drug benefits equivalent to Medicare prescription drug benefits. See Note 17 Goodwill and Other Asset Impairments under Part II, Item 8, of this report for additional information on the goodwill impairment charges. Additional variations are discussed below.

Variations in effective tax rates for Ameren s business segments and for the Ameren Companies between 2010 and 2009 were as follows.

Ameren Missouri (UE)

UE s effective tax rate was higher, primarily because of the change in tax treatment of retiree health care costs, along with the decreased impact of favorable net amortization of property-related regulatory assets and liabilities and other permanent items on higher pretax book income.

Ameren Illinois (AIC)

The effective tax rate was higher, primarily because of the decreased impact of favorable net amortization of property-related regulatory assets and liabilities and permanent items on higher pretax book income.

Merchant Generation

The effective tax rate was lower in the Merchant Generation segment, because of items detailed below at Genco, partially offset by the impact of state tax credits related to capital investments and decreased Internal Revenue Code Section 199 production activity deductions on a pretax book loss.

Genco

The effective tax rate increased, after excluding the impact of the nondeductible goodwill impairment charge, primarily because of the change in tax treatment of retiree health care costs and changes to reserves for uncertain tax positions mitigated by the increased impact of state tax credits, Internal Revenue Code Section 199 production activity deductions and investment tax credit amortization on lower pretax book income.

2009 versus 2008

Ameren Corporation

Ameren s effective tax rate in 2009 was higher than the effective tax rate in 2008 because of variations discussed below. Variations in effective tax rates for Ameren s business segments and for the Ameren Companies between 2009 and 2008 were as follows.

Ameren Missouri (UE)

UE s effective tax rate was lower, primarily because of higher favorable net amortization of property-related regulatory assets and liabilities, partially mitigated by changes to reserves for uncertain tax positions.

Ameren Illinois (AIC)

The effective tax rate was higher, primarily because of the decreased impact of net amortization of property-related regulatory assets and liabilities, investment tax credit amortization, and permanent items on higher pretax book income.

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Merchant Generation

The effective tax rate was higher at the Merchant Generation segment because of items detailed below at Genco, along with the impact of deferred tax adjustments due to changes in state apportionment.

Genco

The effective tax rate increased, primarily because of the decreased impact of Internal Revenue Code Section 199 production activity deductions, along with changes to reserves for uncertain tax positions.

Income from Discontinued Operations, Net of Tax

Ameren Illinois (AIC)

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed a two-step corporate internal reorganization. The first step of the reorganization was the AIC Merger. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. AIC determined that the operating results of AERG qualified for discontinued operations presentation. We have therefore segregated AERG s operating results and presented them separately as discontinued operations for all periods in this report. For Ameren s financial statements, AERG s results of operation remain classified as continuing operations. See Note 16 Corporate Reorganization and Discontinued Operations under Part II, Item 8, of this report for additional information.

AIC s income from discontinued operations (AERG) decreased $74 million in 2010, compared with 2009. AERG s results of operations were included in AIC s consolidated statement of income for all periods prior to October 1, 2010. The inclusion of only nine months in 2010 contributed to the decrease in income from discontinued operations as well as a decrease in electric margins caused by lower realized revenue per megawatt sold and higher fuel and related transportation costs. The decrease was partially offset by a reduction in income tax expense primarily caused by lower pretax book income.

AIC s income from discontinued operations (AERG) increased $62 million in 2009, compared with 2008. The increase in income from discontinued operations was caused by a $94 million increase in AERG s electric margins during 2009, compared with 2008, primarily because of higher revenues allocated to AERG under its power supply agreement with Marketing Company as a result of higher reimbursable expenses and higher generation relative to Genco in accordance with the AERG PSA. Additionally, AERG s other operations and maintenance expenses decreased $22 million, primarily because of a $9 million reduction in plant maintenance costs and an $11 million reduction in asset impairment charges. Factors reducing income from discontinued operations (AERG) included a $30 million increase in income tax expense primarily because of higher pretax book income, a $12 million increase in interest charges primarily because of increased intercompany borrowings, and an $11 million increase in depreciation and amortization expenses primarily because of capital additions.

LIQUIDITY AND CAPITAL RESOURCES

The tariff-based gross margins of Ameren s rate-regulated utility operating companies continue to be a principal source of cash from operating activities for Ameren and its rate-regulated subsidiaries. A diversified retail customer mix of primarily rate-regulated residential, commercial, and industrial classes and a commodity mix of natural gas and electric service provide a reasonably predictable source of cash flows for Ameren, UE and AIC. For operating cash flows, Marketing Company sells power through primarily market-based contracts with wholesale and retail customers. In addition to using cash flows from operating activities, the Ameren Companies use available cash, credit facility borrowings, commercial paper issuances, money pool borrowings, or other short-term borrowings from affiliates to support normal operations and other temporary capital requirements. The Ameren Companies may reduce their credit facility or short-term borrowings with cash from operations or, at their discretion, with long-term borrowings or, in the case of Ameren subsidiaries, with equity infusions from Ameren. The Ameren Companies expect to incur significant capital expenditures over the next five years as they comply with environmental regulations and make significant investments in their electric and natural gas utility infrastructure to improve overall system reliability. Ameren intends to finance those capital expenditures and investments with a blend of equity and debt so that it maintains a capital structure in its rate-regulated businesses of approximately 50% to 55% equity. The Ameren Companies plan to implement their long-term financing plans for debt, equity, or equity-linked securities in order to finance their operations appropriately, meet scheduled debt maturities, and maintain financial strength and flexibility.

The following table presents net cash provided by (used in) operating, investing and financing activities for the years ended December 31, 2010, 2009 and 2008:

	Net Cash Provided By Operating Activities			Net Cash (Used In) Investing Activities			Net Cash Provided By (Used In) Financing Activities		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Ameren[(a)]	**$ 1,842**	$ 1,977	$ 1,524	**$ (1,112)**	$ (1,789)	$ (2,097)	**$ (807)**	$ 342	$ 310
UE	**978**	972	543	**(706)**	(955)	(1,033)	**(337)**	250	305
AIC	**597**	859	488	**(257)**	(452)	(577)	**(324)**	(151)	103
Genco	**280**	253	421	**(29)**	(389)	(366)	**(251)**	139	(54)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

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Cash Flows from Operating Activities

2010 versus 2009

Ameren Corporation

Ameren s cash from operating activities decreased in 2010 compared with 2009. The following items contributed to the decrease in cash from operating activities during 2010, compared with 2009:

- A $116 million decrease in billed revenues, net of payments to suppliers, for pass-through natural gas commodity costs primarily caused by higher-priced natural gas injected into storage during 2008 and billed to customers in 2009.
- Accounts receivable and unbilled revenue balances increased by $106 million, primarily because of higher utility rates and colder December weather in 2010, compared with December 2009.
- Deferred FAC costs increased $100 million as net base fuel costs incurred at UE exceeded the amounts allowed in base rates due to higher fuel costs and lower off-system sales as a result of warmer weather increasing native load demand.
- Deferred budget billing balances increased by $74 million, partially as a result of warmer summer weather, which increased sales volumes over budget-billed amounts.
- An overall $56 million increase in collateral posted with counterparties due, in part, to the items discussed at the subsidiaries below, offset by a $105 million reduction in collateral posted by nonregistrant subsidiaries, primarily due to changes in the market price of power.
- A $53 million decrease in cash from operating activities associated with the December 2005 Taum Sauk incident, primarily as a result of reduced insurance recoveries. See Note 15 Commitments and Contingencies under Part II, Item 8, of this report for additional Taum Sauk information.
- A $39 million increase in payments related to the Callaway nuclear plant refueling and maintenance outage that occurred in 2010, but did not occur in 2009.
- A $14 million increase in payments associated with major outages at coal-fired plants, primarily at UE.
- A $12 million increase in property tax payments caused primarily by higher assessed tax rates in Missouri.
- A $10 million one-time donation in 2010 for customer assistance programs required by the 2009 Illinois energy legislation that authorized the bad debt rate adjustment mechanism and was approved by the ICC in February 2010.
- Payments for professional services, additional franchise taxes, and other administrative items necessary to complete the AIC Merger and AERG distribution totaled $8 million.

The following items reduced the decrease in Ameren s cash from operating activities during 2010, compared with 2009:

- Electric and natural gas margins, as discussed in Results of Operations, increased by $212 million, excluding impacts of MTM transactions.
- Income tax refunds of $92 million in 2010, compared with income tax payments of $9 million in 2009. The refund primarily resulted from an acceleration of depreciation deductions authorized by economic stimulus legislation.
- Ameren reduced its coal inventory levels, primarily at the Merchant Generation segment, in 2010. The impact of the inventory reduction is estimated to have resulted in cash savings of $69 million in 2010.
- A $32 million decrease in major storm restoration costs.
- Contributions to the pension and postretirement plans were $31 million lower in 2010.
- A $14 million reduction in severance payments as a result of the voluntary and involuntary separation programs initiated in both years.

UE

UE s cash from operating activities increased in 2010 compared with 2009. The following items contributed to the increase in cash from operating activities during 2010, compared with 2009:

- Higher electric and natural gas margins as discussed in Results of Operations including the benefit of MoPSC-approved electric rate increases effective on March 1, 2009, and June 21, 2010, as well as favorable weather conditions. Margins increased by $281 million, excluding the impacts of MTM transactions.

- A $31 million reduction in collateral posted with counterparties due in part to improved credit ratings and to changes in the market price of power and natural gas.
- A $13 million decrease in major storm restoration costs.
- Contributions to the pension and postretirement plans were $8 million lower in 2010.
- A $5 million reduction in severance payments as a result of the voluntary and involuntary separation programs initiated in both years.

The following items reduced the increase in UE s cash from operating activities during 2010, compared with 2009:

- A $102 million decrease in income tax refunds, primarily due to higher pretax book income and a reduction in 2010 of the benefit of a change in tax treatment of electric generation plant expenditures taken in 2009.
- Deferred FAC costs increased $100 million as net base fuel costs incurred at UE exceeded the amounts allowed in base rates due to higher fuel costs and lower off-system sales as a result of warmer weather increasing native load demand.

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A $53 million decrease in cash from operating activities associated with the December 2005 Taum Sauk incident discussed above.
A $39 million increase in payments related to a Callaway nuclear plant refueling and maintenance outage that occurred in 2010, but did not occur in 2009.
A $24 million increase in payments associated with major outages at coal-fired plants.
A $12 million increase in property tax payments, caused primarily by higher assessed tax rates.

AIC

AIC s cash from operating activities associated with continuing operations decreased in 2010 compared with 2009. The following items contributed to the decrease in cash from operating activities associated with continuing operations during 2010, compared with 2009:

A $192 million increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas and collateral posting requirements.
Accounts receivable and unbilled revenue balances increased by $183 million, primarily because of higher utility rates and colder December weather in 2010, compared with December 2009.
A $98 million decrease in billed revenue, net of payments to suppliers, for pass-through natural gas commodity costs primarily caused by higher-priced natural gas injected into storage during 2008 and billed to customers in 2009.
Deferred budget billing balances increased by $60 million, partially as a result of warmer summer weather, which increased sales volumes over budget billed amounts.
A $10 million one-time donation in 2010 for customer assistance programs required by the 2009 Illinois legislation that authorized the bad debt rate adjustment mechanism and was approved by the ICC in February 2010.
Payments for professional services, additional franchise taxes, and other administrative items necessary to complete the AIC Merger and AERG distribution, which totaled $7 million.
In 2009, AIC received $5 million from Marketing Company for the costs of upgrades to AIC s electric transmission system. There was no such receipt in 2010.

The following items reduced the decrease in AIC s cash from operating activities associated with continuing operations during 2010, compared with 2009:

Electric and natural gas margins, as discussed in Results of Operations, increased by $187 million, excluding the impacts of MTM transactions.
Income tax refunds of $52 million in 2010, compared with income tax payments of $61 million in 2009. The refund primarily resulted from an acceleration of depreciation deductions authorized by economic stimulus legislation.
A $19 million decrease in major storm restoration costs.
Contributions to the pension and postretirement plans were $11 million lower in 2010.
A $6 million decrease in interest payments, primarily due to the first mortgage bond maturity in June 2009.

AIC s cash from operating activities associated with discontinued operations decreased in 2010 compared with 2009. AERG s cash flows were included in AIC s consolidated statement of cash flows for all periods prior to October 1, 2010. The inclusion of only nine months in 2010 was the primary cause of the decrease in cash flows, along with a reduction in receipts from Marketing Company under the AERG PSA primarily due to lower market prices, as discussed in Results of Operations. A decrease in income tax payments, primarily due to lower pretax book income, and an acceleration of depreciation deductions authorized by economic stimulus legislation partially offset the decrease in AERG s operating cash flows.

Genco

Genco s cash from operating activities increased in 2010 compared with 2009. The following items contributed to the increase in cash from operating activities during 2010, compared with 2009:

A $73 million decrease in income tax payments, primarily due to lower pretax book income, deductions relating to environmental expenditures, and an acceleration of depreciation deductions authorized by economic stimulus legislation.
Reduced coal inventory levels in 2010, which are estimated to have resulted in cash savings of $50 million in 2010.
Lower labor expenditures resulting from staff reductions and fewer major outages at its coal-fired plants.

- A $7 million reduction in use tax payments as Genco and EEI began claiming tax exemptions and credits for purchase transactions related to their generation operations.
- Contributions to the pension plans were $6 million lower in 2010.

The following items reduced the increase in Genco s cash from operating activities during 2010, compared with 2009:

- Electric margins, as discussed in Results of Operations, decreased by $99 million, excluding impacts of MTM transactions.
- A $13 million increase in interest payments, primarily due to the senior unsecured notes issued in November 2009, which required interest payments in 2010, but not in 2009.

2009 versus 2008

Ameren Corporation

Ameren s cash from operating activities increased in 2009 compared with 2008. The following items contributed

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to the increase in cash from operating activities during 2009, compared with 2008:

- A $256 million increase in cash from operating activities associated with the December 2005 Taum Sauk incident. The increase was a result of a $65 million increase in insurance recoveries and a $191 million reduction in payments compared with 2008. During 2009, UE received a property insurance settlement payment from all but three of the property insurance carriers. See Note 15 Commitments and Contingencies under Part II, Item 8, of this report for information about the Taum Sauk incident.
- A $198 million decrease in payments for natural gas injections into storage because of lower prices.
- A $97 million decrease in income tax payments primarily at UE.
- The over-collected deferred budget billing balance increased by $27 million, partially caused by a reduction in commodity costs and a decrease in sales volumes compared to budgeted billed amounts.
- Less cash used for operations and maintenance activities, because many plant-related projects were reduced, deferred, or cancelled and because of the absence of a Callaway nuclear plant refueling and maintenance outage in 2009.

The following items reduced the increase in Ameren s cash from operating activities during 2009, compared with 2008:

- A $75 million increase in interest payments, primarily due to the payments at the subsidiaries discussed below and Ameren s senior secured notes issued in May 2009, which required an interest payment in 2009, but not in 2008.
- A decrease in natural gas costs over-recovered from customers under the PGA.
- A $35 million increase in pension and postretirement plan contributions.
- Lower electric margins, as discussed in Results of Operations, including the absence in 2009 of the 2008 lump-sum settlement payment received by Genco from a coal mine owner for the early termination of a coal supply contract.
- A $21 million decrease in customer advances for construction.
- The 2009 voluntary and involuntary separation programs, which resulted in severance payments of $16 million.
- An increase in annual incentive compensation payments.
- An $8 million increase in cash payments for major storm restoration costs.

UE

UE s cash from operating activities increased in 2009 compared with 2008. The following items contributed to the increase in cash from operating activities during 2009, compared with 2008:

- Income tax refunds of $208 million in 2009 compared with income tax payments of $130 million in 2008. The significant change in income taxes was primarily a result of an acceleration of deductions due to economic stimulus legislation and a change in tax treatment of electric generation plant expenditures.
- A $256 million increase in cash from operating activities associated with the December 2005 Taum Sauk incident, as discussed above.
- A $20 million decrease in payments for natural gas injections into storage because of lower prices.
- Higher electric margins as discussed in Results of Operations.
- An increase in natural gas costs over-recovered from customers under the PGA.
- Less cash used for operations and maintenance activities, because several plant-related projects were reduced, deferred, or cancelled and because of the absence of a Callaway nuclear plant refueling and maintenance outage in 2009.

The following items reduced the increase in UE s cash from operating activities during 2009, compared with 2008:

- The collection of an $85 million affiliate receivable in 2008 that did not occur in 2009.
- A $39 million increase in interest payments, primarily due to the senior secured notes issued in April 2008, June 2008, and March 2009.
- A $16 million increase in pension and other postretirement plan contributions.
- A $10 million increase in energy efficiency expenditures for new customer programs.
- A $6 million increase in major storm restoration costs.
- The 2009 voluntary and involuntary separation programs, which resulted in severance payments of $6 million.

AIC

AIC s cash from operating activities associated with continuing operations increased in 2009 compared with 2008. The following items contributed to the increase in cash from operating activities associated with continuing operations during 2009, compared with 2008:

- A $178 million decrease in payments for natural gas injections into storage because of lower prices.
- A $176 million net reduction in collateral posted with suppliers due in part to improved credit ratings.
- Higher electric and natural gas margins as discussed in Results of Operations.
- Accounts receivable and unbilled revenue balances decreased by $167 million, primarily because of milder weather and lower natural gas commodity costs.
- The over-collected deferred budget billing balance increased by $44 million, partially caused by a reduction in commodity costs and a decrease in sales volumes compared to budgeted billed amounts.

The following items reduced the increase in AIC s cash from operating activities associated with continuing operations during 2009, compared with 2008:

- Income tax payments of $61 million in 2009, compared with income tax refunds of $72 million in 2008, primarily due to higher pretax book income.

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- A decrease in natural gas costs over-recovered from customers under the PGA.
- A $21 million increase in interest payments primarily due to the senior secured notes issued in October 2008.
- A $21 million reduction in customer advances for construction.
- A $7 million increase in pension and other postretirement plan contributions.

AIC s cash from operating activities associated with discontinued operations decreased in 2009 compared with 2008. Factors contributing to the decrease in cash from operating activities at AERG during 2009, compared with 2008, included income tax payments of $68 million in 2009, compared with income tax refunds of $8 million in 2008, primarily due to higher pretax book income; increased coal purchases to build inventories at the Duck Creek generating facility as a result of switching coal blends in 2009; and the absence of $5 million, net of premiums, of replacement power insurance recoveries received in 2008 from an affiliate, as the policy was not renewed. Factors partially reducing the decrease in cash from operating activities at AERG during 2009, compared with 2008, included a $98 million increase in receipts from Marketing Company under the AERG PSA, primarily because of increased generation levels relative to Genco, as discussed in Results of Operations, and a $4 million reduction in funding required by the 2007 Illinois Settlement Agreement.

Genco

Genco s cash from operating activities decreased in 2009 compared with 2008. The following items contributed to the decrease in cash from operating activities during 2009, compared with 2008:

- Electric margins, as discussed in Results of Operations, decreased by $265 million, excluding impacts of MTM transactions. A one-time lump-sum settlement payment was received in 2008 from a coal mine owner for early termination of a contract, which was included in electric margins in 2008 and did not recur in 2009.
- A $9 million increase in interest payments, primarily due to the senior unsecured notes issued in April 2008.
- The 2009 voluntary and involuntary separation programs resulted in severance payments of $4 million.

The following items reduced the decrease in Genco s cash from operating activities during 2009, compared with 2008:

- A $78 million reduction in income tax payments primarily because of lower pretax book income at EEI.
- Reduced coal purchases in 2009 as generation levels declined.

Pension Funding

Ameren s pension plans are funded in compliance with income tax regulations and to meet federal funding or regulatory requirements. As a result, Ameren expects to

fund its pension plans at a level equal to the greater of the pension expense or the legally required minimum contribution. Considering Ameren s assumptions at December 31, 2010, its investment performance in 2010, and its pension funding policy, Ameren expects to make annual contributions of $75 million to $110 million in each of the next five years, with aggregate estimated contributions of $470 million. We expect UE s, AIC s, and Genco s portion of the future funding requirements to be 63%, 28% and 9%, respectively. These amounts are estimates. They may change with actual investment performance, changes in interest rates, changes in our assumptions, any pertinent changes in government regulations, and any voluntary contributions. In 2010, Ameren contributed $81 million to its pension plans. See Note 11 Retirement Benefits under Part II, Item 8, of this report and Outlook for additional information.

Cash Flows from Investing Activities

2010 versus 2009

Ameren s cash used in investing activities decreased by $677 million during 2010, compared with 2009. There was a $673 million decrease in capital expenditures as compared with 2009 as a result of reductions in planned capital expenditures for the distribution system and power plant improvements during 2010, a $109 million reduction in capital expenditures to repair severe storm damage, and the completion of power plant scrubber projects in the Merchant Generation segment during 2009 and early 2010. Cash flows from investing activities in 2010 also benefited from the sale of 25% of Genco s Columbia CT facility and other properties.

UE s cash used in investing activities decreased by $249 million during 2010, compared with 2009. There was a $264 million decrease in capital expenditures as compared with 2009 as a result of reductions in planned capital expenditures for the distribution system and power plant improvements during 2010, as well as a $74 million reduction in capital expenditures to repair severe storm damage. This cash benefit was reduced by a $10 million increase in nuclear fuel expenditures related to the timing of purchases and a $12 million net decrease in nuclear decommissioning trust fund activities.

AIC s cash used in investing activities decreased by $195 million during 2010, compared with 2009. There was a $70 million decrease in capital expenditures compared with 2009 as a result of reductions in planned capital expenditures for the distribution system during 2010 in response to revenues granted being significantly less than requested in a rate proceeding, as well as a $35 million reduction in capital expenditures to repair severe storm damage. Similar planned capital expenditure reductions at AERG resulted in the $85 million decrease in capital expenditures of discontinued operations. Additionally, AIC s advances to ATXI for construction under a joint ownership agreement decreased during 2010 as the project approached completion. AIC received funding for this construction under a generator interconnection agreement related to ongoing transmission upgrade projects.

Genco s cash used in investing activities decreased by $360 million during 2010, compared with 2009. Reductions in planned capital expenditures, as well as completion of power plant scrubber projects during 2009, resulted in a $221 million decrease in capital expenditures compared with 2009. Cash flows from investing activities in 2010 also benefited from the $18 million of proceeds Genco received from the sale of 25% of its Columbia CT facility and net repayment of money pool advances.

2009 versus 2008

Ameren used less cash for investing activities in 2009 than in 2008. Net cash used for capital expenditures decreased in 2009 as a result of efforts to reduce, defer or cancel capital expenditure programs in light of economic conditions and the completion of power plant scrubber projects in the Merchant Generation segment. Additionally, a $93 million decrease in nuclear fuel expenditures due to timing of purchases and a $10 million decrease in emission allowance purchases, due to lower prices and lower generation levels, as well as reduced emission levels resulting from completion of plant scrubber projects in 2009, benefited cash during 2009.

UE s cash used in investing activities decreased by $78 million during 2009, compared with 2008. Nuclear fuel expenditures decreased $93 million as a result of the timing of purchases. Cash used in investing activities in 2009 did not benefit from the receipt of $36 million in proceeds from intercompany note receivables with Ameren and one of its subsidiaries, as occurred during 2008. Capital expenditures were consistent year over year. Reductions in planned capital expenditures for distribution system and power plant improvements in 2009 were offset by increased expenditures to repair severe storm damage and $93 million of rebuilding expenditures at Taum Sauk.

AIC s cash used in investing activities during 2009 decreased by $125 million compared with 2008, as a result of a $165 million decrease in capital expenditures of discontinued operations (AERG). The decrease in capital expenditures was driven by ongoing efforts to reduce, defer, or cancel capital expenditure programs. This cash benefit was reduced by an $20 million increase in utility capital expenditures to repair severe storm damage and by an increase in advances to ATXI for construction under a joint ownership agreement. AIC received funding for this construction under a generator interconnection agreement related to ongoing transmission upgrade projects.

Genco s cash used in investing activities increased by $23 million in 2009 compared with 2008 because of $73 million of net money pool advances in 2009. Capital expenditures decreased $37 million, principally because of reduced spending for power plant scrubber projects. One scrubber project was completed in November 2009, and a second scrubber project was completed in 2010. Emission allowance purchases decreased $10 million because of

lower prices and lower generation levels, as well as reduced emission levels resulting from the completion of a plant scrubber project in 2009, which resulted in a benefit to cash in 2009.

Capital Expenditures

The following table presents the capital expenditures by the Ameren Companies for the years ended December 31, 2010, 2009, and 2008:

Capital Expenditures	**2010**	**2009**	**2008**
Ameren(a)	**$ 1,031**	$ 1,704	$ 1,896
UE	**608**	872	874
AIC	**286**	356	345
Genco	**95**	316	353

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

Ameren s 2010 capital expenditures principally consisted of the following expenditures at its subsidiaries. UE spent $130 million toward two scrubbers at its Sioux power plant, which were completed in 2010. At Genco, there was a cash outlay of $29 million for power plant scrubber projects. The scrubbers are necessary to comply with environmental regulations. Other capital expenditures were made principally to maintain, upgrade, and expand the reliability of the transmission and distribution systems of UE and AIC, as well as to fund various plant upgrades.

Ameren s 2009 capital expenditures principally consisted of the following expenditures at its subsidiaries. UE spent $173 million toward two scrubbers at its Sioux power plant, and $93 million toward the Taum Sauk rebuild, and it incurred storm-related expenditures of $78 million.

AIC incurred storm-related expenditures of $38 million. At Genco, there was a cash outlay of $169 million for power plant scrubber projects. The scrubbers are necessary to comply with environmental regulations. Other capital expenditures were made principally to maintain, upgrade, and expand the reliability of the transmission and distribution systems of UE and AIC as well as various plant upgrades.

Ameren s 2008 capital expenditures principally consisted of the following expenditures at its subsidiaries. UE spent $149 million toward a scrubber at one of its power plants, and incurred storm-related expenditures of $12 million. AIC incurred storm-related expenditures of $18 million. At Genco, there was a cash outlay of $205 million for power plant scrubber projects. The scrubbers are necessary to comply with environmental regulations. Other capital expenditures were made principally to maintain, upgrade, and expand the reliability of the transmission and distribution systems of UE and AIC as well as various plant upgrades.

The following table estimates the capital expenditures that will be incurred by the Ameren Companies from 2011 through 2015, including construction expenditures, capitalized interest for the Merchant Generation business,

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allowance for funds used during construction for our rate-regulated utility business, and estimated expenditures for compliance with known and existing environmental regulations:

	2011	2012 - 2015		Total	
UE	$ 685	$ 2,500 -	$ 3,400	$ 3,185 -	$ 4,085
AIC	310	1,550 -	2,050	1,860 -	2,360
Genco	180	600 -	850	780 -	1,030
Other	75	450 -	600	525 -	675
Ameren(a)	$ 1,250	$ 5,100 -	$ 6,900	$ 6,350 -	$ 8,150

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

UE s estimated capital expenditures include transmission, distribution, and generation-related investments, as well as expenditures for compliance with environmental regulations discussed below. AIC s estimated capital expenditures are primarily for electric and natural gas transmission and distribution-related investments. Genco s estimated capital expenditures are primarily for compliance with environmental regulations and upgrades to existing coal and gas-fired generating facilities discussed below.

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

Environmental Capital Expenditures

Ameren, UE and Genco will incur significant costs in future years to comply with existing and known federal EPA and state regulations regarding SO_2, NO_x, and mercury emissions from coal-fired power plants.

In addition to existing laws and regulations governing our facilities, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren, UE and Genco, that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; revised ambient air quality standards for SO_2 and NO_x emissions that increase the stringency of the existing ozone ambient air quality standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is also expected to propose new regulations under the Clean Water Act that could require significant capital expenditures such as new water intake structures or cooling towers at our power plants; NSPS and

emission guidelines for greenhouse gas emissions applicable to new and existing electric generating units; and a MACT standard for the control of hazardous air pollutants such as mercury and acid gases from power plants. Such new regulations may be challenged with lawsuits, so the timing of their ultimate implementation is uncertain. Although many details of these future regulations are unknown, the combined effect of the new and proposed environmental regulations may result in significant capital expenditures and/or increased operating costs over the next five to eight years for Ameren, UE and Genco. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. As a result, these regulations could require us to close or to significantly alter the operation of our generating facilities, which could have an adverse effect on our results of operations, financial position, and liquidity.

The estimates in the table below contain all of the known capital costs to comply with existing environmental regulations and our preliminary assessment of the potential impacts of the EPA s proposed regulations for coal combustion byproducts, the CATR, and the revised ambient air quality standards for SO_2 and NO_x emissions as of December 31, 2010. The estimates in the table below assume that coal combustion byproducts will ultimately be regarded as nonhazardous. The estimates shown in the table below could change depending upon additional federal or state requirements, regulation of greenhouse gas emissions, new hourly ambient air quality standards or changes to existing standards for SO_2 and NO_x emissions, the requirements under a MACT standard for the control of hazardous air pollutants such as mercury and acid gases, the requirements under the finalized CATR, any new regulations under the Clean Water Act, a hazardous classification of coal combustion by products, new technology, and variations in costs of material or labor, or alternative compliance strategies, among other factors.

	2011		2012 - 2015				2016 - 2020				Total			
UE[a]	$	35	$	850 -	$	1,050	$	1,380 -	$	1,610	$	2,265 -	$	2,695
Genco		125		470 -		580		50 -		60		645 -		765
AERG		10		125 -		160		5 -		10		140 -		180
Ameren	$	170	$	1,445 -	$	1,790	$	1,435 -	$	1,680	$	3,050 -	$	3,640

(a) UE s expenditures are expected to be recoverable from ratepayers.

See Note 15 Commitments and Contingencies under Part II, Item 8, of this report for a further discussion of environmental matters, including global climate change.

Cash Flows from Financing Activities

2010 versus 2009

During 2010, we replaced and extended the expiration of our credit facilities, and we sought to reduce our reliance on borrowings from these credit facilities, and reduce long-term debt outstanding while maintaining adequate cash balances for working capital needs.

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Ameren had an $807 million net use of cash from financing activities in 2010, compared with a $342 million net source of cash in 2009. During 2010, Ameren s cash flow from operating activities of $1.8 billion exceeded its capital expenditures of $1.0 billion and common stock dividend requirements of $368 million. Ameren utilized this cash to redeem $310 million of long-term debt and $52 million of preferred stock in 2010. During 2009, Ameren issued $1 billion of senior debt and $634 million in common stock and used the proceeds to repurchase, redeem, and fund maturities of $631 million of long-term debt, to reduce short-term borrowings, and to fund capital expenditures and other working capital needs at UE, AIC, and Genco.

UE had a $337 million net use of cash from financing activities in 2010, compared with a $250 million net source of cash in 2009. Planned reductions of expenditures, allowed UE to use cash from operations and credit facility borrowings to fund its capital expenditures and working capital needs without issuing additional senior debt or capital contributions from Ameren. Additionally, during 2010, these efforts allowed UE to redeem $70 million of long-term debt, including its 7.69% Series A subordinated debentures; to redeem all outstanding shares of its $7.64 Series preferred stock; to increase common stock dividends by $60 million; and to reduce short-term and intercompany borrowing repayments by $343 million, compared with 2009.

AIC s net cash used in financing activities increased by $173 million in 2010 compared with 2009. Reduction of planned expenditures allowed it to use cash from operations to fund its capital expenditures and working capital needs without the issuance of additional senior debt or capital contributions from Ameren. Additionally, AIC s common stock dividends increased $35 million compared with 2009, and CILCO redeemed all of its preferred stock in connection with the AIC Merger. During 2009, Ameren made capital contributions to AIC of $272 million and AIC repaid $250 million of long-term debt and $62 million of short-term borrowing balances.

Genco had a $251 million net use of cash from financing activities in 2010, compared with a $139 million net source of cash in 2009, primarily as a result of reductions of planned expenditures. These efforts allowed Genco to use cash from operations and credit facility borrowings to fund capital expenditures, to meet working capital needs, to repay its $200 million of 8.35% senior notes at maturity, and to repay a net $176 million of intercompany note borrowings in 2010. Additionally, Genco received a capital contribution from Ameren associated with a tax allocation agreement that benefited 2010 cash flows from financing activities. During 2009, Genco issued $249 million of long-term debt and used the proceeds to repay short-term borrowings and to fund general corporate purposes.

2009 versus 2008

During 2009, Ameren and its subsidiaries issued $1 billion of senior debt and $634 million in common stock.

It used the proceeds to repurchase, redeem, and fund maturities of $631 million of long-term debt, to reduce short-term borrowings, and to fund capital expenditures and other working capital needs at UE, AIC and Genco. During 2008, Ameren s subsidiaries issued $1.9 billion of senior debt and $154 million in common stock and used the proceeds to repurchase, redeem, and fund maturities of $842 million of long-term debt, to reduce short-term borrowings, and to fund capital expenditures and other working capital needs at UE, AIC and Genco. Ameren s capital issuance costs increased in 2009 compared with 2008 because of $40 million in banking fees associated with the 2009 Multiyear Credit Agreements and the 2009 Illinois Credit Agreement, and $17 million of issuance costs associated with Ameren s September 2009 common stock issuance, partially offset by a decrease in issuance costs associated with long-term debt. Benefiting 2009 cash from financing activities, compared with 2008, was a $196 million decrease in common stock dividends and a $47 million increase in generator advances received for construction under generator interconnection agreements, net of repayments.

UE s net cash provided by financing activities decreased by $55 million during 2009, compared with 2008, primarily because of $251 million of short-term borrowings repayments in 2009 compared with net short-term borrowings of $169 million in 2008, a $350 million decrease in the issuances of long-term debt, and a $184 million increase in net repayments under an intercompany borrowing arrangement with Ameren. Benefits to cash for 2009, compared with 2008, included a $436 million capital contribution from Ameren funded by the proceeds of Ameren s September 2009 common stock issuance, a $378 million decrease in redemptions of long-term debt, and an $89 million decrease in common stock dividend payments. The proceeds from the capital contribution were primarily used to reduce outstanding short-term borrowings.

AIC had a $151 million net use of cash from financing activities in 2009, compared with a $103 million net source of cash in 2008, primarily as a result of efforts to improve its liquidity position in response to the turmoil experienced in the capital and credit markets during 2009 and 2008. These efforts included no long-term debt issuances in 2009, which meant an $880 million decrease in long-term debt issuances from 2008. AIC also received a $272 million capital contribution from Ameren that was made to maintain a capital structure of approximately 50% to 55% equity. Additionally, improved financial results allowed AIC to increase dividend payments from 2008 by $38 million. The change in short-term borrowing arrangements at AERG also affected the 2009 financing activity of discontinued operations as compared with 2008.

Genco had a $139 million net source of cash from financing activities in 2009, compared with a $54 million net use of cash in 2008, primarily as a result of efforts to improve its liquidity position in response to the turmoil experienced in the capital and credit markets during 2009

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and 2008, as well as its efforts to reduce, defer and cancel expenditures. As a result of these efforts, Genco decreased common stock dividends by $178 million and short-term borrowing repayments by $100 million. These benefits to

cash during the 2009 period were slightly offset by a $106 million decrease in net money pool borrowings and a $51 million decrease in the issuance of long-term debt.

Credit Facility Borrowings and Liquidity

The liquidity needs of the Ameren Companies are typically supported through the use of available cash, short-term intercompany borrowings, drawings under committed bank credit facilities, or commercial paper issuances. See Note 4 Credit Facility Borrowings and Liquidity under Part II, Item 8, of this report for additional information on credit facilities, short-term borrowing activity, relevant interest rates, and borrowings under Ameren s utility and non-state-regulated subsidiary money pool arrangements.

The following table presents the committed bank credit facilities of Ameren and the Ameren Companies, and their availability, as of December 31, 2010:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren and UE:			
2010 Missouri Credit Agreement[a][b]	September 2011	$ 800	$ 445[c]
Ameren and Genco:			
2010 Genco Credit Agreement[a]	September 2013	500	400
Ameren and AIC:			
2010 Illinois Credit Agreement[a]	September 2013	800	800
Ameren:			
$20 million revolving credit facility	June 2012	20	-

(a) The Ameren Companies may access these credit facilities through intercompany borrowing arrangements.
(b) This credit agreement expires on September 10, 2013. The borrowing sublimit of UE will mature and expire on September 9, 2011, subject to extension on a 364-day basis, as requested by the borrower and approved by the lenders, or for a longer period upon receipt of any and all required federal or state regulatory approvals, as permitted under the credit agreement, but in no event later than September 10, 2013. UE is seeking state regulatory approval to extend the maturity date of its borrowing sublimit under the 2010 Missouri Credit Agreement to September 10, 2013.
(c) In addition to amounts drawn on these facilities, the amount available is further reduced by standby letters of credit issued under the facilities. The amount of such letters of credit at December 31, 2010, was $15 million.

The 2010 Credit Agreements are used to support Ameren and UE s commercial paper programs. Ameren may at its discretion use any of the 2010 Credit Agreements to support its commercial paper programs, subject to its borrowing sublimits. At December 31, 2010, Ameren had $269 million of commercial paper outstanding, which reduced the available amounts under these facilities. Based on outstanding borrowings under the 2010 Credit Agreements (and considering reductions for $15 million of letters of credit issued and $269 million of commercial paper borrowings), the aggregate available amount under the 2010 Credit Agreements at December 31, 2010, was $1.38 billion.

The combined maximum amount available to all of the borrowers, collectively, under the 2010 Credit Agreements is $2.1 billion. The maximum aggregate amount available to each borrower under each facility is shown in the following table (such amount being such borrower s Borrowing Sublimit):

	2010 Missouri Credit Agreement	2010 Genco Credit Agreement	2010

			Illinois Credit Agreement
Ameren	$ 500	$ 500	$ 300
UE	500	(a)	(a)
AIC	(a)	(a)	800
Genco	(a)	500	(a)

(a) Not applicable.

These credit facilities were also available for use, subject to applicable regulatory short-term borrowing authorizations, by EEI or by other Ameren non-state-regulated subsidiaries through direct short-term borrowings from Ameren and by most of Ameren s non-rate-regulated subsidiaries, including, but not limited to, Ameren Services, Resources Company, AERG and Marketing Company, through a non-state-regulated subsidiary money pool agreement. Ameren has money pool agreements with and among its subsidiaries to coordinate and to provide for certain short-term cash and working capital requirements. Separate money pools are maintained for utility and non-state-regulated entities. In addition, a unilateral borrowing agreement among Ameren, AIC, and Ameren Services enables AIC to make short-term borrowings directly from Ameren. Pursuant to the terms of the agreement, the aggregate amount of borrowings outstanding at any time by AIC under the unilateral borrowing agreement and the utility money pool agreement, together with any outstanding external credit facility borrowings by AIC, may not exceed $500 million, pursuant to authorization from the ICC. AIC is not currently borrowing under the unilateral borrowing agreement. Ameren Services is responsible for operation and administration of the money pool agreements. See Note 4 Credit Facility Borrowings and Liquidity under Part II, Item 8, of this report for a detailed explanation of the money pool arrangements and the unilateral borrowing agreement.

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On June 2, 2010, Ameren entered into a $20 million revolving credit facility ($20 Million Facility) that matures on June 1, 2012. The $20 Million Facility has been fully drawn since June 15, 2010. Borrowings under the $20 Million Facility bear interest at a rate equal to the applicable LIBOR plus 2.25% per annum. The obligations of Ameren under the $20 Million Facility are unsecured. No subsidiary of Ameren is a party to, guarantor of, or borrower under the facility. See Note 4 Credit Facility Borrowings and Liquidity under Part II, Item 8, of this report for additional information.

The issuance of short-term debt securities by Ameren s utility subsidiaries is subject to approval by FERC under the Federal Power Act. In March 2010, FERC issued an order authorizing the issuance of up to $1 billion of short-term debt securities for UE. The authorization was effective as of April 1, 2010, and terminates on

March 31, 2012. On October 1, 2010, FERC authorized AIC to issue up to $1 billion of short-term debt securities. The authorization became effective immediately and terminates on September 30, 2012.

On July 16, 2010, FERC granted Genco s request for unlimited long and short-term debt issuance authorization. EEI has unlimited short-term debt authorization from FERC.

The issuance of short-term debt securities by Ameren is not subject to approval by any regulatory body.

The Ameren Companies continually evaluate the adequacy and appropriateness of their liquidity arrangements given changing business conditions. When business conditions warrant, changes may be made to existing credit facilities or to other short-term borrowing arrangements.

Long-term Debt and Equity

The following table presents the issuances of common stock and the issuances, redemptions, repurchases and maturities of long-term debt and preferred stock (net of any issuance discounts and including any redemption premiums) for the years 2010, 2009, and 2008 for the Ameren Companies. For additional information related to the terms and uses of these issuances and the sources of funds and terms for the redemptions, see Note 5 Long-term Debt and Equity Financings under Part II, Item 8, of this report.

	Month Issued, Redeemed, Repurchased or Matured	**2010**	**2009**	**2008**
Issuances				
Long-term debt				
Ameren:				
8.875% Senior unsecured notes due 2014	May	**$ -**	$ 423	$ -
UE:				
6.00% Senior secured notes due 2018	April	**-**	-	250
6.70% Senior secured notes due 2019	June	**-**	-	449
8.45% Senior secured notes due 2039	March	**-**	349	-
Genco:				
6.30% Senior unsecured notes due 2020	November	**-**	249	-
7.00% Senior unsecured notes due 2018	April	**-**	-	300
AIC:				
6.25% Senior secured notes due 2018	April	**-**	-	336
8.875% Senior secured notes due 2013	December	**-**	-	150
9.75% Senior secured notes due 2018	October	**-**	-	394
Total Ameren long-term debt issuances		**$ -**	$ 1,021	$ 1,879
Common stock				
Ameren:				
21,850,000 shares at $25.25	September	**$ -**	$ 552	$ -
DRPlus and 401(k)	Various	**80**	82	154
Total common stock issuances		**$ 80**	$ 634	$ 154
Total Ameren long-term debt and common stock issuances		**$ 80**	$ 1,655	$ 2,033

Redemptions, Repurchases and Maturities							
Long-term debt							
Ameren:							
8.70% Senior unsecured notes due 2009 (formerly CILCORP)	October	**$**	**-**	$	124	$	-
9.375% Senior bonds due 2029 (formerly CILCORP)	December		**-**		253		-

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	Month Issued, Redeemed, Repurchased or Matured	2010	2009	2008
UE:				
City of Bowling Green capital lease (Peno Creek CT)	Various	**$ 4**	$ 4	$ 4
2000 Series B environmental improvement bonds due 2035	April	**-**	-	63
2000 Series A environmental improvement bonds due 2035	May	**-**	-	64
2000 Series C environmental improvement bonds due 2035	May	**-**	-	60
1991 Series environmental improvement bonds due 2020	May	**-**	-	43
6.75% Series first mortgage bonds due 2008	May	**-**	-	148
7.69% Series A subordinated deferrable interest debentures due 2036	September	**66**	-	-
AIC:				
2004 Series pollution control bonds due 2025	April	**$ -**	$ -	$ 35
2004 Series pollution control bonds due 2039	April	**-**	-	19
Series 2001 Non-AMT bonds due 2028	May	**-**	-	112
Series 2001 AMT bonds due 2017	May	**-**	-	75
1997 Series A pollution control bonds due 2032	May	**-**	-	70
1997 Series B pollution control bonds due 2032	May	**-**	-	45
1997 Series C pollution control bonds due 2032	June	**-**	-	35
5.375% Senior secured notes due 2008	December	**-**	-	15
7.50% Series mortgage bonds due 2009	June	**-**	250	-
7.61% Series 1997-2 first mortgage bonds due 2017	September	**40**	-	-
Note payable to IP Special Purpose Trust 5.65% Series due 2008	Various	**-**	-	54
Genco:				
Senior notes Series D 8.35% due 2010	November	**200**	-	-
Total Ameren long-term debt redemptions, repurchases and maturities		**$ 310**	$ 631	$ 842
Preferred Stock				
UE:				
$7.64 Series	August	**$ 33**	$	$ -
AIC:				
5.85% Series	July	**-**	-	16
4.50% Series	August	**11**	-	-
4.64% Series	August	**8**	-	-
4.08% Series[(a)]	September	**7**	-	-
4.20% Series[(a)]	September	**5**	-	-
4.26% Series[(a)]	September	**4**	-	-
4.42% Series[(a)]	September	**3**	-	-
4.70% Series[(a)]	September	**5**	-	-
7.75% Series[(a)]	September	**9**	-	-
Total Ameren preferred stock redemptions and repurchases		**$ 85**	$ -	$ 16
Total Ameren long-term debt and preferred stock redemptions, repurchases and maturities		**$ 395**	$ 631	$ 858

(a) In September 2010, Ameren contributed to the capital of AIC (formally IP), without the payment of any consideration, all of the IP preferred stock owned by Ameren ($33 million). IP cancelled these preferred shares.

In November 2008, Ameren, as a well-known seasoned issuer, along with AIC s predecessor companies, CIPS, CILCO and IP, and Genco, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in November 2011. As amended in December 2010, Ameren, AIC and Genco may offer securities pursuant to the November 2008 Form S-3 shelf registration statement. In June 2008, UE, as a well-known seasoned issuer, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in June 2011.

A Form S-3 registration statement was filed by Ameren with the SEC in July 2008, and supplemented in December

2010, authorizing the offering of six million additional shares of its common stock under DRPlus. Shares of common stock sold under DRPlus are, at Ameren s option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated transactions. Ameren is currently selling newly issued shares of its common stock under DRPlus.

Ameren is also selling newly issued shares of common stock under its 401(k) plan pursuant to an effective SEC Form S-8 registration statement. Under DRPlus and its 401(k) plan, Ameren issued 3.0 million, 3.2 million, and 4.0 million shares of common stock in 2010, 2009, and 2008, respectively, which were valued at $80 million, $82 million, and $154 million for the respective years.

In September 2009, Ameren issued and sold 21.85 million shares of its common stock at $25.25 per share, for proceeds of $535 million, net of $17 million of issuance costs. Ameren used the offering proceeds to make investments in its rate-regulated utility subsidiaries in the form of capital contributions to UE and AIC of $436 million and $99 million, respectively.

The Ameren Companies may sell securities registered under their effective registration statements if market conditions and capital requirements warrant such sales. Any offer and sale will be made only by means of a prospectus that meets the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

Indebtedness Provisions and Other Covenants

See Note 4 Credit Facility Borrowings and Liquidity and Note 5 Long-term Debt and Equity Financings under Part II, Item 8, of this report for a discussion of covenants and provisions (and applicable cross-default provisions) contained in our bank credit and term loan agreements and in certain of the Ameren Companies indenture agreements and articles of incorporation.

At December 31, 2010, the Ameren Companies were in compliance with their credit agreements, indentures, and articles of incorporation provisions and covenants.

We consider access to short-term and long-term capital markets a significant source of funding for capital requirements not satisfied by our operating cash flows. Inability to raise capital on reasonable terms, particularly during times of uncertainty in the capital markets, could negatively affect our ability to maintain and expand our businesses. After assessing our current operating performance, liquidity, and credit ratings (see Credit Ratings below), we believe that we will continue to have access to the capital markets. However, events beyond our control may create uncertainty in the capital markets or make access to the capital markets uncertain or limited. Such events could increase our cost of capital and adversely affect our ability to access the capital markets.

Dividends

Ameren paid to its shareholders common stock dividends totaling $368 million, or $1.54 per share, in 2010, $338 million, or $1.54 per share, in 2009, and $534 million, or $2.54 per share, in 2008. The payout of common stock dividends exceeded net income in 2010 because of noncash goodwill and other impairment charges recorded during 2010. The payout rate based on net income in 2009 and 2008 was 55% and 88%, respectively. Dividends paid to common shareholders in relation to net cash provided by operating activities for the same periods were 20% in 2010, 17% in 2009 and 35% in 2008.

The amount and timing of dividends payable on Ameren s common stock are within the sole discretion of Ameren s board of directors. The board of directors has not set specific targets or payout parameters when declaring

common stock dividends. However, as it has done in the past, the board of directors is expected to consider various issues, including Ameren s overall payout ratio, payout ratios of our peers, projected cash flow and potential future cash flow requirements, historical earnings and cash flow, projected earnings, impacts of regulatory orders or legislation, and other key business considerations. On February 9, 2011, the board of directors of Ameren declared a quarterly dividend on Ameren s common stock of 38.5 cents per share, payable on March 31, 2011, to shareholders of record on March 9, 2011.

Certain of our financial agreements and corporate organizational documents contain covenants and conditions that, among other things, restrict the Ameren Companies payment of dividends in certain circumstances. At December 31, 2010, none of these circumstances existed at the Ameren Companies and, as a result, they were allowed to pay dividends.

Under UE s mortgage indenture, $31 million of total retained earnings as of December 31, 2010, was restricted against payment of common dividends, except those dividends payable in common stock, which left $2 billion of free and unrestricted retained earnings at December 31, 2010. AIC s articles of incorporation require its dividend payments on common stock to be based on ratios of common stock to total capitalization and other provisions related to certain operating expenses and accumulations of earned surplus. Genco s indenture includes restrictions that prohibit it from making any dividend payments on common stock if debt service coverage ratios are below a defined threshold.

UE, AIC and Genco as well as certain other nonregistrant Ameren subsidiaries are subject to Section 305(a) of the Federal Power Act, which makes it unlawful for any officer or director of a public utility, as defined in the Federal Power Act, to participate in the making or paying of any dividend from any funds properly included in capital account. The meaning of this limitation has never been clarified under the Federal Power Act or FERC regulations. However, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividends are not excessive, and (3) there is no self-dealing on the part of corporate officials. At a minimum, Ameren believes that dividends can be paid by its subsidiaries that are public utilities from net income and retained earnings. In addition, under Illinois law, AIC may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless AIC has specific authorization from the ICC.

In its application for the FERC orders approving the AIC Merger and the AERG distribution, Ameren committed to maintain a minimum of 30% equity in its capital structure at AIC following the AIC Merger and the AERG distribution.

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The following table presents common stock dividends paid by Ameren Corporation and by Ameren s subsidiaries to their respective parents:

	2010	2009	2008
UE	**$ 235**	$ 175	$ 264
AIC	**133**	98	60
Genco	**-**	43	221
Nonregistrants including eliminations	**-**	22	(11)
Dividends paid by Ameren	**$ 368**	$ 338	$ 534

Certain of the Ameren Companies have issued preferred stock, which provides for cumulative preferred stock dividends. Each company s board of directors considers the declaration of the preferred stock dividends to shareholders of record on a certain date, stating the date on

which the dividend is payable and the amount to be paid. See Note 5 Long-Term Debt and Equity Financings under Part II, Item 8, of this report for further detail concerning the preferred stock issuances.

Contractual Obligations

The following table presents our contractual obligations as of December 31, 2010. See Note 11 Retirement Benefits under Part II, Item 8, of this report for information regarding expected minimum funding levels for our pension plans. These expected pension funding amounts are not included in the table below. In addition, routine short-term purchase order commitments are not included.

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	After 5 Years
Ameren:[(a)]					
Long-term debt and capital lease obligations[(b)(c)]	$ 7,021	$ 155	$ 534	$ 705	$ 5,627
Short-term debt and credit facility borrowings	729	269	460	-	-
Interest payments[(d)]	4,793	455	885	755	2,698
Operating leases[(e)]	336	39	66	50	181
Other obligations[(f)]	7,486	1,977	2,297	1,025	2,187
Total cash contractual obligations	$ 20,365	$ 2,895	$ 4,242	$ 2,535	$ 10,693
UE:					
Long-term debt and capital lease obligations[(c)]	$ 3,960	$ 5	$ 383	$ 229	$ 3,343
Interest payments[(d)]	2,837	233	451	414	1,739
Operating leases[(e)]	146	13	25	24	84
Other obligations[(f)]	3,700	751	933	645	1,371
Total cash contractual obligations	$ 10,643	$ 1,002	$ 1,792	$ 1,312	$ 6,537
AIC:					
Long-term debt[(c)]	$ 1,811	$ 150	$ 151	$ 51	$ 1,459
Interest payments[(d)]	1,059	125	240	209	485
Operating leases[(e)]	7	2	2	2	1
Other obligations[(f)]	2,504	646	760	344	754
Total cash contractual obligations	$ 5,381	$ 923	$ 1,153	$ 606	$ 2,699
Genco:					
Long-term debt[(c)]	$ 825	$ -	$ -	$ -	$ 825
Credit facility borrowings	100	-	100	-	-
Interest payments	769	59	118	118	474
Operating leases[(e)]	139	11	22	20	86
Other obligations[(f)]	863	427	431	5	-
Total cash contractual obligations	$ 2,696	$ 497	$ 671	$ 143	$ 1,385

(a) Includes amounts for registrant and nonregistrant Ameren subsidiaries and intercompany eliminations.
(b) Excludes fair-market value adjustments of long-term debt of $5 million for AIC.
(c) Excludes unamortized discount of $18 million at Ameren, $6 million at UE, $9 million at AIC, and $1 million at Genco.
(d) The weighted-average variable-rate debt has been calculated using the interest rate as of December 31, 2010.
(e) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. Ameren s $2 million annual obligation for these items is 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 because that period is indefinite.
(f) See Other Obligations within Note 15 Commitments and Contingencies under Part II, Item 8 of this report, for discussion of items included herein.

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As of December 31, 2010, the amounts of unrecognized tax benefits under the authoritative accounting guidance for uncertain tax positions were $246 million, $164 million, $56 million, and $20 million for Ameren, UE, AIC, and Genco, respectively. It is reasonably possible to expect that the settlement of an unrecognized tax benefit will result in an underpayment or overpayment of tax and related interest. However, there is a high degree of uncertainty with respect to the timing of cash payments or receipts associated with unrecognized tax benefits. The amount and timing of certain payments or receipts is not reliably estimable or determinable at this time. See Note 13 Income Taxes under Part II, Item 8, of this report for information regarding the Ameren Companies unrecognized tax benefits and related liabilities for interest expense.

Off-Balance-Sheet Arrangements

At December 31, 2010, none of the Ameren Companies had off-balance-sheet financing arrangements other than operating leases entered into in the ordinary course of business. None of the Ameren Companies expect to engage in any significant off-balance-sheet financing arrangements in the near future.

Credit Ratings

The credit ratings of the Ameren Companies affect our liquidity, our access to the capital markets and credit markets, our cost of borrowing under our credit facilities and collateral posting requirements under commodity contracts.

The following table presents the principal credit ratings of the Ameren Companies by Moody s, S&P, and Fitch effective on the date of this report:

	Moody s	S&P	Fitch
Ameren:			
Issuer/corporate credit rating	Baa3	BBB-	BBB
Senior unsecured debt	Baa3	BB+	BBB
Commercial paper	P-3	A-3	F2
UE:			
Issuer/corporate credit rating	Baa2	BBB-	BBB+
Secured debt	A3	BBB+	A
AIC:			
Issuer/corporate credit rating	Baa3	BBB-	BBB
Secured debt	Baa1	BBB	BBB+
Senior unsecured debt	Baa3	BBB-	BBB-
Genco:			
Issuer/corporate credit rating	Baa3	BBB-	BBB
Senior unsecured debt	Baa3	BBB-	BBB

Collateral Postings

Any adverse change in the Ameren Companies credit ratings may reduce access to capital and trigger additional collateral postings and prepayments. Such changes may also increase the cost of borrowing and fuel, power, and gas supply, among other things, resulting in a negative

impact on earnings. Cash collateral postings and prepayments made with external parties including postings related to exchange-traded contracts at December 31, 2010, were $166 million, $15 million and $116 million at Ameren, UE and AIC, respectively. The amount of cash collateral external counterparties posted with Ameren was less than $1 million at December 31, 2010. Sub-investment-grade issuer or senior unsecured debt ratings (lower than BBB- or Baa3) at December 31, 2010, could have resulted in Ameren, UE, AIC or Genco being required to post additional collateral or other assurances for certain trade obligations amounting to $274 million, $93 million, $111 million, and $28 million, respectively.

Changes in commodity prices could trigger additional collateral postings and prepayments at current credit ratings. If market prices were 15% higher than December 31, 2010, levels in the next 12 months and 20% higher thereafter through the end of the term of the commodity contracts, then Ameren, UE, AIC or Genco could be required to post additional collateral or other assurances for certain trade obligations up to approximately $61 million, $13 million, $- million, and $- million, respectively. If market prices were 15% lower than December 31, 2010, levels in the next 12 months and 20% lower thereafter through the end of the term of the commodity contracts, then Ameren, UE, AIC or Genco could be required to post additional collateral or other assurances for certain trade obligations up to approximately $107 million, $9 million, $62 million, and $- million, respectively.

The cost of borrowing under our credit facilities can also increase or decrease depending upon the credit ratings of the borrower. A credit rating is not a recommendation to buy, sell, or hold securities. It should be evaluated independently of any other rating. Ratings are subject to revision or withdrawal at any time by the rating organization.

OUTLOOK

Below are some key trends that may affect the Ameren Companies financial condition, results of operations, or liquidity in 2011 and beyond.

Economy and Capital and Credit Markets

Economic conditions in our service territory continued to improve in 2010, which contributed to higher sales volume, exclusive of abnormal weather impacts, to Ameren s rate-regulated utilities native load customers. However, weak economic conditions, declining natural gas prices, and other factors resulted in reduced power prices and a decline in observable industry market multiples for companies similar to Ameren. Weak economic conditions expose the Ameren Companies to greater risk of default by counterparties, potentially higher bad debt expenses, and the risk of impairment of goodwill and long-lived assets, among other things. In the third quarter of 2010, both Ameren and Genco recorded goodwill and long-lived asset impairment

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charges at their Merchant Generation reporting unit. A failure of reporting units to achieve forecasted operating results and cash flows, an unfavorable change in forecasted operating results and cash flows, new environmental rules and regulations, or a decline of observable industry market multiples in the future could result in the recognition of additional goodwill or long-lived asset impairment charges.

For 2010, the actual return on investment of Ameren s pension plan and postretirement plan assets exceeded the expected return. These returns and future returns will impact our future pension and postretirement expenses and pension funding levels.

During 2010, we observed an improvement in the U.S. capital and credit markets and lower interest rates on new issuances of investment grade debt securities compared with 2008 and 2009, when these markets experienced extreme volatility. The Ameren Companies continue to have access to the capital markets at commercially acceptable rates. A future disruption in the capital or credit markets could limit our ability to access the capital and credit markets, which our business depends upon, and result in increased financing costs.

On September 10, 2010, Ameren and certain of its subsidiaries entered into new multiyear credit facility agreements. These facilities cumulatively provide $2.1 billion of credit through September 10, 2013, subject to borrowing sublimit extensions. The costs of these credit facilities are less than the costs of the facilities they replaced. Costs are being amortized over the term of the 2010 Credit Agreements. Fees for UE will be deferred for recovery in future customer rates. In addition, borrowing rates under the facilities decreased, including, in the case of Ameren, from LIBOR plus 3.25%, under the prior credit facilities, to LIBOR plus 2.05%.

At December 31, 2010, Ameren, on a consolidated basis, had available liquidity, in the form of cash on hand and amounts available under its existing credit facilities, of approximately $1.9 billion, which was equivalent to the amount of available liquidity at December 31, 2009.

Economic conditions could affect the Ameren Companies results of operations, financial position and liquidity. See Item 1A. Risk Factors in this report for additional information.

We believe that our liquidity is adequate given our expected operating cash flows, capital expenditures, and related financing plans. However, there can be no assurance that significant changes in economic conditions, disruptions in the capital and credit markets, or other unforeseen events will not materially affect our ability to execute our expected operating, capital or financing plans.

Current Capital Expenditure Plans

Between 2011 and 2020, Ameren expects to invest up to $3.6 billion, in the aggregate, to retrofit its coal-fired power plants with pollution control equipment in compliance with existing and known environmental laws and regulations. Any pollution control investments will result in decreased plant availability during construction and significantly higher ongoing operating expenses. Approximately 74% of this investment is expected to be in UE s operations, and it is therefore expected to be recoverable from ratepayers, subject to prudency reviews. Regulatory lag may materially affect the timing of such recovery and, therefore affect our cash flows and related financing needs. The recoverability of amounts expended in our Merchant Generation operations will depend on whether market prices for power adjust as a result of market conditions reflecting increased environmental costs for coal-fired generators.

Future federal and state legislation or regulations that mandate limits on emissions would result in significant increases in capital expenditures and operating costs. Excessive costs to comply with future legislation or regulations might force Ameren and other similarly situated electric power generators to close some coal-fired facilities. Investments to control emissions at Ameren s coal-fired power plants to comply with future legislation or regulations would significantly increase future capital expenditures and operations and maintenance expenses, which if excessive could result in the closure of coal-fired power plants, impairment of assets, or otherwise materially adversely affect Ameren s results of operations, financial position, and liquidity.

UE continues to evaluate its longer-term needs for new baseload and peaking electric generation capacity. UE s integrated resource plan filed with the MoPSC in February 2011 included the expectation that new baseload generation capacity would be required between 2020 and 2030. Because of the significant time required to plan, acquire permits for, and build a baseload power plant, UE continues to study future generation alternatives, including energy efficiency programs that could help defer new plant construction. To prepare for the long-term need for baseload capacity, and to prepare for potentially more stringent environmental regulation of coal-fired power plants, which could lead to the retirement of current baseload assets, UE is taking steps to preserve options to meet future demand. These steps include seeking improvements in regulatory treatment of energy efficiency investments, evaluating potential sites for natural gas-fired generation, and pursuing an ESP for an additional unit at its Callaway nuclear plant site subject to passage of state legislation that would ensure rate recovery of permit costs.

UE is considering filing an application to obtain an ESP from the NRC at the Callaway nuclear plant site. In December 2010 and January 2011, the Missouri Energy Partnership Act was separately introduced in both the Missouri Senate and House of Representatives. The purpose of this legislation is to maintain an option for nuclear power in the state of Missouri, recover the costs of the ESP for a period up to 20 years, and provide appropriate consumer protections. Should the Missouri legislation be enacted into law, UE plans to file an ESP application with the NRC in 2011. NRC approval of an ESP application often takes three to four years. As of December 31, 2010, UE had capitalized approximately $67 million relating to its efforts to construct a new nuclear unit. All of these incurred costs will remain capitalized while management assesses all options to maximize the value of its investment in this project. If all efforts are permanently abandoned or if management concludes it is probable the cost incurred will be disallowed in rates, it is possible that a charge to earnings could be recognized in a future period.

UE intends to submit a license extension application with the NRC to extend its existing Callaway nuclear plant s operating license by 20 years so that the license will expire in 2044. UE cannot predict whether or when the NRC will approve the license extension.

Over the next few years, we expect to make significant investments in our electric and natural gas infrastructure and to incur increased operations and maintenance expenses to improve overall system reliability. We are committed to aligning our operations and maintenance spending and capital investments within our rate-regulated businesses with the revenue and related cash flow levels provided by our regulators. We expect these costs or investments at our rate-regulated businesses to be ultimately recovered in rates, subject to prudency reviews by regulators, although rate case outcomes and regulatory lag could materially impact the timing of such recovery and, therefore, our cash flows, related financing needs and the timing in which we are able to proceed with these projects. We are projecting labor and material costs for these capital expenditures will increase over time.

ATX intends to build projects initially within Illinois and Missouri, with the potential for expanding to other areas in the future. ATX s initial investments are expected to be the Grand Rivers projects, the first of which involves building a 345 kilovolt line across the state of Illinois, from the Missouri border to the Indiana border. The investment could total more than $1.3 billion through 2021, with a potential investment of $265 million from 2011 to 2015.

In September 2010, Resources Company announced that it signed a cooperative agreement with the DOE that could lead to repowering Genco s Meredosia plant. This would create the world s first full-scale, oxy-combustion coal-fired power plant designed for permanent CO_2 capture and storage. Ameren and two independent companies will assess the project in phases to validate its scope, cost, schedule and commercial viability. If the first phases are successful and the project has received regulatory approval, Ameren and its partners will initiate the construction necessary to repower the plant.

Increased investments for environmental compliance, reliability improvement, and new baseload capacity will result in higher depreciation and financing costs.

Revenues

The earnings of UE and AIC are largely determined by the regulation of their rates by state agencies. Rising costs, including labor, material, depreciation, and financing costs, coupled with increased capital and operations and maintenance expenditures targeted at enhanced distribution system reliability and environmental compliance, are expected. Ameren, UE and AIC anticipate regulatory lag until their requests to increase rates to recover such costs on a timely basis are granted by state regulators. Ameren, UE and AIC expect to file rate cases frequently.

In future rate cases, UE and AIC will continue to seek cost recovery and tracking mechanisms from their state regulators to reduce the effects of regulatory lag.

In April 2010, the ICC issued a rate order for AIC, which was amended in May 2010, that approved a net increase in annual revenues for electric delivery service of $35 million and a net decrease in annual revenues for natural gas delivery service of $20 million. The rate changes became effective in May 2010. AIC as well as some intervenors requested a rehearing with the ICC. In November 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the net $15 million authorized in the ICC s May 2010 amended rate order. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues became effective on November 19, 2010.

The April 2010 ICC order confirmed the previously approved 80% allocation of fixed nonvolumetric residential and commercial natural gas customer charges and approved a higher percentage of recovery of fixed nonvolumetric electric residential and commercial customer charges. The percentage of costs to be recovered through fixed nonvolumetric electric residential and commercial customer and meter charges increased from 27% to 40%.

AIC filed a request with the ICC in February 2011 to increase its annual revenues for electric delivery service by $60 million. AIC also filed a request with the ICC in February 2011 to increase its annual revenues for natural gas delivery service by $51 million. AIC is using a future test year, 2012, in each of these rate requests, which is designed to reduce regulatory lag. See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for additional information. A decision by the ICC in these proceedings is required by January 2012.

AIC filed a request with FERC in January 2011 to increase its annual revenues for electric delivery service for its wholesale customers by approximately $11 million. AIC provides electric delivery service to nine wholesale customers. These wholesale delivery revenues are treated as a deduction in AIC s revenue requirement in retail rate filings with the ICC. AIC reached an agreement with one customer prior to the filings, and that customer s new rates are expected to

become effective on April 1, 2011. With respect to the remaining eight customers, AIC requested that the new rates become effective on February 1, 2011. In February 2011, these eight customers filed protests with FERC objecting to the proposed rates. The final rates and corresponding revenue amounts will become known after the FERC proceeding concludes, either through settlements reached between customers and AIC, or after the filings are fully litigated. The FERC is expected to rule on the January filings in 2011, and to allow the new rates to take effect subject to refund. We cannot predict the ultimate outcome of these filings or their impact on Ameren s or AIC s results of operations, financial position, or liquidity.

In May 2010, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $230 million, including $119 million to cover higher fuel costs and lower revenue from sales outside UE s system. The rate changes became effective on June 21, 2010. See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for additional information about other significant provisions of the MoPSC s order.

The provisions of the May 2010 MoPSC order also resulted in the recognition of new regulatory assets. These new regulatory assets are being amortized over the next two to five years beginning July 2010, as described in Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report. The increased amortization of the regulatory assets and the increase in annual depreciation expense due to the adoption of the life span depreciation methodology is estimated to increase UE s pretax expense by $25 million in 2011.

Noranda appealed certain aspects of the MoPSC s January 2009 electric rate order to the Circuit Court of Stoddard County and was granted a stay by the Circuit Court of Stoddard County as it applies specifically to Noranda s electric service account until the court renders its decision on the appeal. In September 2010, UE filed an appeal with the Missouri Court of Appeals for the Southern District of Missouri. The Court of Appeals will conduct an independent review of the MoPSC s January 2009 electric order. A decision by the Court of Appeals is not expected until at least the third quarter of 2011.

On February 16, 2011, the Missouri Office of Public Counsel (MoOPC) made a filing with the MoPSC in which the MoOPC argued that the December 20, 2010 Order Granting Stay Pursuant to Section 386.520 (Stay Order), discussed below, of the Circuit Court of Cole County, Missouri (Circuit Court) should apply to all UE customers rather than to just the four UE industrial customers that requested the Circuit Court to grant these industrial customers request to stay the MoPSC s 2010 Missouri electric rate order as to their billings. On that basis, the MoOPC requested the MoPSC to suspend UE s currently effective rate schedules (approved by the 2010 Missouri electric rate order) and to replace them with UE s previously effective rate schedules (approved by the 2009 Missouri electric rate order) for all customers. If the requested suspension occurs, it would continue until the earlier of the time that a subsequent order is issued by the MoPSC, or an order reversing any such suspension is issued by a court of competent jurisdiction, but in no event beyond the implementation of new electric rates for UE. It is anticipated that new electric rates for UE will take effect by early August 2011, pursuant to an anticipated MoPSC rate order in UE s currently pending electric rate proceeding. If the currently effective 2010 rate schedules are suspended for all customers such that UE is only able to charge customers under its previously effective rate schedules for service provided for the period March through August 2011, the reduced charges, which would reflect the difference between billings under the 2010 Missouri electric rate order and billings under the 2009 Missouri electric rate order, are estimated at approximately $100 million and would result in corresponding reductions in pretax earnings and cash flows.

Also on February 16, 2011, the Missouri Industrial Energy Consumers (MIEC), of which the four UE industrial customers referred to above are members, made a filing with the MoPSC in response to the MoOPC filing discussed above. In its filing, MIEC supported the position set forth in the MoOPC filing that the Stay Order should apply to all UE customers, except that MIEC requested the MoPSC to suspend UE s currently effective rate schedules, including its FAC, and replace them with UE s rate schedules approved by the MoPSC in its 2007 electric rate order. If the requested suspension occurs, it would continue until the earlier of the time that a subsequent order is issued by the MoPSC, or an order reversing any such suspension is issued by a court of competent jurisdiction, but in no event beyond the implementation of new electric rates for UE. As noted, it is anticipated that new electric rates for UE will take effect by early August 2011. If the currently effective 2010 rate schedules (including the FAC) are suspended for all customers such that UE is only able to charge customers under its previously effective rate schedules for service provided for the period March through August 2011, the reduced charges, which would reflect the difference between billings under the 2010 Missouri electric rate order and billings under the 2007 Missouri electric rate order, including FAC billings, are estimated at approximately $300 million and would result in corresponding reductions in pretax earnings and cash flows.

The filings by the MoOPC and MIEC relate to the December 20, 2010 Stay Order, in which the Circuit Court granted the request of four UE industrial customers to stay the MoPSC s 2010 Missouri electric rate order and to require those customers to pay into the Circuit Court s registry the difference between their billings under the 2010 Missouri electric rate order and their billings under a Missouri electric rate order that became effective in June 2007, the last UE rate order for which appeals have been exhausted. On February 15, 2011, the four UE industrial customers posted the bond required by the Stay Order and are expected to begin making the required payments into the Circuit Court s registry.

The Stay Order does not address the merits of the appeals of the MoPSC s 2010 electric rate order or the 2009 electric rate order, which will be addressed in the ordinary course of the judicial review process. The judicial review process typically takes 18 to 24 months to complete following the initiation of the process. At this time, UE does not believe any aspect of the 2009 and 2010 electric rate increases authorized by the 2009 and 2010 Missouri electric rate orders are probable of refund to UE s customers. If UE were to conclude that some portion of these rate increases become probable of refund to UE s customers, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision was made.

UE disagrees with the Stay Order, as well as the related filings made by the MoOPC and MIEC with the MoPSC. With respect to further proceedings regarding the Stay Order, the pending review proceedings regarding the 2009 and 2010 Missouri electric rate orders and the MoOPC s and MIEC s filings with the MoPSC, UE will continue to address the merits of those orders and filings through the judicial and regulatory review processes. See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for additional information.

Taum Sauk was not available to generate electricity for off-system revenues during 2009; however, UE included an adjustment in the calculation of the FAC for Taum Sauk off-system revenues. Therefore, UE s customers received the benefit of Taum Sauk s historical off-system revenues even though the plant was not operational. Upon Taum Sauk s return to service, which occurred in April 2010, the adjustment figure was eliminated and UE s earnings and cash flows from operations increased. Taum Sauk is expected to increase UE s margins during the first quarter of 2011 by $7 million.

UE filed a request with the MoPSC in September 2010 to increase its annual revenues for electric service by approximately $263 million. Of that request, approximately $110 million relates to recovery of the costs of installing and operating two scrubbers at UE s Sioux plant. Also included in this requested increase is a $73 million anticipated increase in normalized net fuel costs above the net fuel costs included in base rates previously authorized by the MoPSC in its May 2010 electric rate order. Absent initiation of this general rate proceeding, 95% of this amount would have been reflected in rate adjustments implemented under UE s FAC. Capital additions relating to enhancements at the rebuilt Taum Sauk facility were also included in the increase request. In February 2011, the MoPSC staff responded to the UE request for an electric service rate increase. The MoPSC staff recommended an increase to UE s annual revenues of between $45 million and $99 million based on a return on equity of 8.25% to 9.25%. Included in this recommendation was approximately $50 million of increases in normalized
net fuel costs and $32 million of asset disallowances relating to the Sioux plant scrubbers. Other parties also made recommendations through testimony filed in this case. See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for additional information. A decision by the MoPSC in this proceeding is required by the end of July 2011.

In January 2011, the MoPSC approved a stipulation and agreement that resolved a June 2010 request by UE to increase annual natural gas revenues. The stipulation and agreement authorized an increase in annual natural gas delivery revenues of $9 million, which included approximately $2 million of annual revenues previously collected through the ISRS rider for the test year ended December 31, 2009. The new rates became effective on February 20, 2011. The stipulation and agreement approved a revised block-rate structure for residential customers that results in more certainty of margin revenue recovery regardless of weather conditions or conservation efforts as recovery is less dependent on usage.

Missouri law requires the MoPSC to complete prudence reviews of UE s FAC at least every 18 months. In August 2010, the MoPSC staff completed a prudence review of the FAC from March 1, 2009, to September 30, 2009. The MoPSC staff contends that UE should have included in the FAC calculation all costs and revenues associated with certain contract sales that were made due to the loss of Noranda load caused by a severe ice storm in January 2009. UE disagrees with the MoPSC staff s classification of these transactions and opposes their inclusion in the FAC calculation. UE recognized margin associated with these contracts of $17 million during the period reviewed by the MoPSC and an additional $25 million of margin subsequent to September 30, 2009. If the MoPSC were to agree with the staff position, and if the MoPSC s order were to be upheld by the courts on appeal, UE would be required to pass through to customers the $42 million in margin associated with these contracts resulting in a charge to UE s earnings. The MoPSC is expected to issue an order for this review in 2011. If UE were to conclude that some portion of these contested FAC amounts become probable of refund to UE s customers, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision is made.

As part of the 2007 Illinois Electric Settlement Agreement, AIC entered into financial contracts with Marketing Company (for the benefit of Genco and AERG), to lock in energy prices for 400 to 1,000 megawatts annually of its round-the-clock power requirements during the period June 1, 2008, to December 31, 2012, at then-relevant market prices. Under the terms of the 2007 Illinois Electric Settlement Agreement, these financial contracts are deemed prudent and AIC is permitted full recovery of their costs in rates.

Volatile power prices in the Midwest can affect the amount of revenues Ameren and Genco generate by marketing power into the wholesale and spot markets and can influence the cost of power purchased in the spot markets.

With few scheduled maintenance outages in 2011 and 2012, the Merchant Generation segment expects to have available generation from its coal-fired plants of 34 million megawatthours in each year. However, the Merchant Generation segment s actual generation levels will be significantly influenced by whether market prices for power in those years justify the generation output, among other things.

The availability and performance of Ameren s and Genco s Merchant Generation fleet can materially affect their revenues. The Merchant Generation segment expects to generate 29.5 million megawatthours of power from its coal-fired plants in 2011 (Genco 22 million) based on expected power prices. Should power prices rise more than expected, the Merchant Generation segment has the capacity and availability to sell more generation.

The marketing strategy for the Merchant Generation segment is to optimize generation output in a low risk manner to minimize volatility of earnings and cash flow, while seeking to capitalize on its low-cost generation fleet to provide solid, sustainable returns. To accomplish this strategy, the Merchant Generation segment has established hedge targets for near-term years. Through a mix of physical and financial sales contracts, Marketing Company targets to hedge Merchant Generation s expected output by 80% to 90% for the following year, 50% to 70% for two years out, and 30% to 50% for three years out. As of February 15, 2011, Marketing Company had hedged approximately 26 million megawatthours of Merchant Generation s expected 2011 generation, at an average price of $46 per megawatthour. For 2012, Marketing Company had hedged approximately 15 million megawatthours of Merchant Generation s forecasted generation sales at an average price of $50 per megawatthour. For 2013, Marketing Company had hedged approximately 7.5 million megawatthours of Merchant Generation s forecasted generation sales at an average price of $42 per megawatthour. Marketing Company has also entered into capacity-only sales contracts for 2011, 2012, and 2013, resulting in expected capacity-only revenues related to these contracts of $47 million, $19 million, and $7 million, respectively. Any unhedged forecasted generation will be exposed to market prices at the time of sale. Prices for power have decreased significantly since mid-2008. As a result, any new physical or financial power sales may be at price levels lower than previously experienced.

Current and future energy efficiency programs developed by UE, AIC and others could result in reduced demand for our electric generation and our electric and natural gas transmission and distribution services. Our regulated operations will seek a regulatory framework that allows either a return on these programs similar to the return that could be earned on supply-side capital investments, or recovery of their costs, within a declining demand environment.

Fuel and Purchased Power

In 2010, 85% of Ameren s electric generation (UE 77%, Genco 99%) was supplied by coal-fired power plants. About 97% of the coal used by these plants (UE 97%, Genco 97%) was delivered by rail from the Powder River Basin in Wyoming. In the past, deliveries from the Powder River Basin have occasionally been restricted because of rail maintenance, weather, and derailments.

As of December 31, 2010, coal inventories for Ameren, UE and Genco were at targeted levels. However, Merchant Generation is targeting a reduction in its coal inventory, relative to previous levels, in 2011. Disruptions in coal deliveries could cause Ameren, UE and Genco to pursue a strategy that could include reducing sales of power during low-margin periods, buying higher-cost fuels to generate required electricity, or purchasing power from other sources.

Ameren s fuel costs (including transportation) are expected to increase in 2011 and beyond. As of February 15, 2011, the average cost of Merchant Generation s baseload hedged fuel costs, which include coal, transportation, diesel fuel surcharges, and other charges, was approximately $23.50 per megawatthour in 2011, $25 per megawatthour in 2012, and $28.50 per megawatthour in 2013. See Item 3 Quantitative and Qualitative Disclosures About Market Risk of this report for additional information about the percentage of fuel and transportation requirements that are price-hedged for 2011 through 2015.

Other Costs

In December 2005, there was a breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility. This resulted in significant flooding in the local area, which damaged a state park. The rebuilt Taum Sauk plant became fully operational in April 2010. Until Ameren s remaining liability insurance claims and the related litigation, as well as its pending regulatory proceeding, are resolved, among other things, we are unable to determine the total impact the breach could have on Ameren s and UE s results of operations, financial position, and liquidity beyond those amounts already recognized. Certain costs associated with the Taum Sauk facility not recovered from property insurers are expected to be recoverable from UE s electric customers. As of December 31, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $89 million that UE believes qualify for recovery in electric rates under the terms of UE s November 2007 state of Missouri settlement agreement, and those costs were included in UE s pending electric rate increase request filed in September 2010. The inclusion of such costs in UE s electric rates is subject to review and approval by the MoPSC. Any amounts not recovered in electric rates, or otherwise, could result in charges to earnings, which

could be material. See Note 15 Commitments and Contingencies under Part II, Item 8, of this report for further discussion of Taum Sauk matters.

UE s Callaway nuclear plant s next scheduled refueling and maintenance outage will be in the fall of 2011. During a scheduled outage, which occurs every 18 months, maintenance and purchased power costs increase, and the amount of excess power available for sale decreases, compared with non-outage years.

Over the next few years, we expect rising employee benefit costs, higher property taxes, and higher insurance premiums as a result of insurance market conditions and loss experience, among other things.

Ameren s Merchant Generation segment is expecting 2011 non-fuel other operations and maintenance expenses to be approximately $310 million, which is approximately 10% greater than other operations and maintenance expenses recorded in 2010. Higher employee-related costs are the primary driver for the expected increase.

The reduction in carrying value for some long-lived and intangible Merchant Generation assets, recognized as a result of Ameren s and Genco s third quarter 2010 impairment tests, as well as a corresponding change in the useful lives for some assets, is not expected to have a material impact on Ameren s or Genco s 2011 net income.

On January 12, 2011, the Illinois governor signed legislation that would increase the state s corporate income tax rate from the current 7.3% to 9.5% (including the replacement tax), starting in 2011. The tax rate is scheduled to decrease to 7.75% in 2015, and it is scheduled to return to 7.3%, in 2025. This corporate income tax rate increase in Illinois is expected to increase Ameren s income tax expense between $5 to $10 million in 2011 (AIC $3 million to $6 million, Genco $1 million to $2 million).

UE, AIC, ATXI and Marketing Company are MISO members. Each member company of MISO is responsible for a portion of MISO s market cost. Recently, some non-Ameren Companies have announced their intention to leave MISO, while other companies have announced plans to study their potential inclusion into MISO. In the near term, it appears likely that more companies will exit MISO than will join it. Ameren could be negatively affected as existing MISO companies leave the RTO as Ameren s operating companies would bear a larger share of MISO s market costs. At this time, Ameren is unable to estimate the effects of these MISO member changes on its results of operation, financial position, and liquidity.

Other

A ballot initiative passed by Missouri voters in November 2008 created a renewable energy portfolio requirement. UE and other Missouri investor-owned utilities will be required to purchase or generate electricity from renewable energy sources equaling at least 2% of native load sales by 2011, with that percentage increasing in subsequent years to at least 15% by 2021, subject to a 1% limit on customer rate impacts. At least 2% of each portfolio requirement must be derived from solar energy. Compliance with the renewable energy portfolio requirement can be achieved through generation, the procurement of renewable energy, or the procurement of renewable energy credits. UE expects that any related costs or investments would ultimately be recovered in rates. In July 2010, the MoPSC issued final rules implementing the State s renewable energy portfolio requirements. In addition to other concerns, UE objected to the MoPSC rules creating geographical restrictions as well as the calculation of the 1% limit on customer rates. In February 2011, the Missouri legislature rejected the contested portion of the MoPSC rules creating geographical restrictions. This legislative action allows UE to comply with the law through its own generation or the procurement of renewable energy or renewable energy credits from sources regardless of geographical location. In August 2010, UE filed an appeal with the Circuit Court of Cole County, Missouri. UE is appealing the portion of the MoPSC rules calculating the 1% limit on customer rates. UE cannot predict when the court will issue a ruling or the ultimate outcome of the appeal.

In September 2010, President Obama signed into law the Small Business Jobs Act. That legislation includes an extension of the bonus depreciation provision to 2010, retroactive to the beginning of 2010. This provision will allow the Ameren Companies to accelerate depreciation deductions on qualifying property for federal income tax purposes that Ameren would have otherwise received over 15 or 20 years. In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Jobs Creation Act of 2010 was signed into law by President Obama. This provision allowed increased acceleration for qualifying property placed in service after September 8, 2010. Ameren s preliminary estimate is that these provisions will result in a reduction of Ameren s 2011 federal income tax payments of between $100 million to $150 million (UE $65 million to $85 million, AIC $35 million to $55 million, Genco $- million to $10 million) and a reduction of Ameren s 2012 federal income tax payments of between $150 million to $200 million (UE $90 million to $105 million, AIC $60 million to $80 million, Genco $- million to $5 million).

AIC s $150 million 6.625% senior secured notes will mature in June 2011. AIC expects to use cash on hand and operating cash flows to pay the bondholders $150 million, plus interest, at the maturity date. Additionally in 2011, AIC is planning to contribute approximately $100 million to Ameren s postretirement benefit plan. This cash contribution will reduce future postretirement expense.

In July 2010, President Obama signed into law the Wall Street Reform and Consumer Protection Act. This law will require additional governmental regulation of derivative and OTC transactions that could expand collateral requirements. The Commodities Futures

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Trading Commission has issued a number of proposed rulemakings to implement the new law. Ameren is currently evaluating the new law and the proposed rulemaking to determine their potential impact to our results of operations, financial position, and liquidity. Depending on how the law is ultimately interpreted in subsequent rulemaking, it could reduce the effectiveness of hedging, increasing the volatility of earnings, and could require increased collateral postings.

In 2010, President Obama signed into law a health care reform bill that makes several fundamental changes to the U.S. health care system. In March 2010, Ameren recorded a $13 million charge relating to the taxation of the Medicare Part D subsidy. The Ameren Companies are currently evaluating the long-term effects of this reform and the health care benefits they currently offer their employees and retirees. Additionally, Ameren will continue to monitor and assess the impact of the health care reforms, including any clarifying regulations issued to address how the provisions are to be implemented. Until those reviews are completed, Ameren is unable to estimate the effects of the new law on its results of operations, financial position, and liquidity.

The above items could have a material impact on our results of operations, financial position, or liquidity. Additionally, in the ordinary course of business, we evaluate strategies to enhance our results of operations, financial position, or liquidity. These strategies may include acquisitions, divestitures, opportunities to reduce costs or increase revenues, and other strategic initiatives to increase Ameren s stockholder value. We are unable to predict which, if any, of these initiatives will be executed. The execution of these initiatives may have a material impact on our future results of operations, financial position, or liquidity.

REGULATORY MATTERS

See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report.

ACCOUNTING MATTERS

Critical Accounting Estimates

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

Accounting Estimate

Uncertainties Affecting Application

Regulatory Mechanisms and Cost Recovery

Ameren, UE and AIC defer costs in accordance with authoritative accounting guidance, and make investments that they assume will be collected in future rates.

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

Basis for Judgment

We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate and any other factors that may indicate whether cost recovery is probable. If facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery or that plant assets are probable of disallowance, we record a charge to earnings, which could be material. See Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for quantification of these assets for each of the Ameren Companies, excluding Genco.

Unbilled Revenue

At the end of each period, UE and AIC project expected usage and estimate the amount of revenue to record for services that have been provided to customers but not yet billed.

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

Basis for Judgment

We base our estimate of unbilled revenue each period on the volume of energy delivered, as valued by a model of billing cycles and historical usage rates and growth by customer class for our service area. This figure is then adjusted for the modeled impact of seasonal and weather variations based on historical results. See the balance sheets for Ameren, UE and AIC, under Part II, Item 8, of this report for unbilled revenue amounts.

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Accounting Estimate

Uncertainties Affecting Application

Derivative Financial Instruments

We account for derivative financial instruments and measure their fair value in accordance with authoritative accounting guidance. The identification and classification of a derivative and the fair value of such derivative must be determined. See Commodity Price Risk and Fair Value of Contracts in Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, Note 7 Derivative Financial Instruments and Note 8 Fair Value Measurements under Part II, Item 8, of this report.

Our ability to assess whether derivative contracts qualify for the NPNS exception
Our ability to consume or produce notional values of derivative contracts
Market conditions in the energy industry, especially the effects of price volatility and liquidity
Valuation assumptions on longer term contracts due to lack of observable inputs
Effectiveness of derivatives that have been designated as hedges
Counterparty default risk

Basis for Judgment

We determine whether to exclude the fair value of certain derivatives from valuation under the NPNS provisions of authoritative accounting guidance after assessing our intent and ability to physically deliver commodities purchased and sold. Further, our forecasted purchases and sales also support our designation of some fair-valued derivative instruments as cash flow hedges. Fair value of our derivatives is measured in accordance with authoritative accounting guidance, which provides a fair value hierarchy that prioritizes inputs to valuation techniques. We use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. When we do not have observable inputs, we use certain assumptions that market participants would use in pricing the asset or liability, including assumptions about risks inherent in the inputs to the valuation. Our valuations also reflect our own assessment of counterparty default risk, using the best internal and external information available. If we were required to discontinue our use of the NPNS exception or cash flow hedge treatment for some of our contracts, the impact of changes in fair value for the applicable contracts could be material to our earnings.

Valuation of Goodwill, Intangible Assets, Long-Lived Assets, and Asset Retirement Obligations

We periodically assess the carrying value of our goodwill, intangible assets, and long-lived assets to determine whether they are impaired. We also review for the existence of asset retirement obligations. If an asset retirement obligation is identified, we determine its fair value and subsequently reassess and adjust the obligation, as necessary.

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

Basis for Judgment

Annually, or whenever events indicate a valuation may have changed, we use various methodologies that we believe market participants would use to determine valuations, including earnings before interest, taxes, depreciation and amortization multiples, and discounted, undiscounted, and probabilistic discounted cash flow models with multiple operating scenarios. The identification of asset retirement obligations is conducted through the review of legal documents and interviews. See Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report for quantification of our goodwill, intangible assets, and asset retirement obligations. See Note 17 Goodwill and Other Asset Impairments under Part II, Item 8, of this report for additional information of our goodwill, intangible asset, and long-lived asset impairment evaluation and charge recorded in 2010.

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Accounting Estimate

Uncertainties Affecting Application

Benefit Plan Accounting

Based on actuarial calculations, we accrue costs of providing future employee benefits in accordance with authoritative accounting guidance regarding benefit plans. See Note 11   Retirement Benefits under Part II, Item 8, of this report.

Future rate of return on pension and other plan assets
Interest rates used in valuing benefit obligations
Health care cost trend rates
Timing of employee retirements and mortality assumptions
Ability to recover certain benefit plan costs from our ratepayers
Changing market conditions impacting investment and interest rate environments
Impacts of the health care reform legislation enacted in 2010

Basis for Judgment

Our ultimate selection of the discount rate, health care trend rate, and expected rate of return on pension and other postretirement benefit plan assets is based on our consistent application of assumption-setting methodologies and our review of available historical, current, and projected rates, as applicable. See Note 11   Retirement Benefits under Part II, Item 8, of this report for sensitivity of Ameren s benefit plans to potential changes in these assumptions.

Accounting for Contingencies

We make judgments and estimates in recording liabilities for claims, litigation, environmental remediation, the actions of various regulatory agencies, or other matters that occur in the normal course of business. We record a loss contingency when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. A gain contingency is not recorded until realized or realizable.

Estimating financial impact of events
Estimating likelihood of outcomes
Regulatory and political environments and requirements
Outcome of legal proceedings, settlements or other factors

Basis for Judgment

The determination of a loss contingency requires significant judgment as to the expected outcome of each contingency in future periods. In making the determination as to the amount of potential loss and the probability of loss, we consider all available evidence including the expected outcome of potential litigation. We record our best estimate of a loss or the minimum value of our estimated range of outcomes if no estimate is better than another estimate within our range of estimates. As additional information becomes available, we reassess the potential liability related to the contingency and revise our estimates. In our evaluation of legal matters, management consults with legal counsel and relies on analysis of relevant case law and legal precedents. See Note 2   Rate and Regulatory Matters, Note 10   Callaway Nuclear Plant, and Note 15 Commitments and Contingencies under Part II, Item 8, of this report for information on the Ameren Companies   contingencies.

Impact of Future Accounting Pronouncements

See Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report.

EFFECTS OF INFLATION AND CHANGING PRICES

Ameren s rates for retail electric and natural gas utility service are regulated by the MoPSC and the ICC. Nonretail electric rates are regulated by FERC. Rate regulation is generally based on the recovery of historical or projected costs. As a result, revenue increases could lag behind changing prices. Inflation affects our operations, earnings, stockholders equity, and financial performance.

The current replacement cost of our utility plant substantially exceeds our recorded historical cost. Under existing regulatory practice, only the historical cost of plant is recoverable from customers. As a result, cash flows designed to provide recovery of historical costs through depreciation might not be adequate to replace the plant in

future years. Ameren s Merchant Generation businesses do not have regulated recovery mechanisms and are therefore dependent on market prices for power to reflect rising costs.

UE recovers the cost of fuel for electric generation and the cost of purchased power by adjusting rates as allowed through an FAC. AIC recovers power supply costs from electric customers by adjusting rates through a rider mechanism to accommodate changes in power prices.

UE and AIC are affected by changes in the cost of electric transmission services. FERC regulates the rates charged and the terms and conditions for electric transmission services. Each RTO separately files regional transmission tariff rates for approval by FERC. All members

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within that RTO are then subjected to those rates. As members of MISO, UE s and AIC s transmission rates are calculated in accordance with MISO s rate formula. The transmission rate is updated in June of each year based on FERC filings. This rate is charged directly to wholesale customers. AIC also charges this rate directly to alternative retail electric suppliers. For Illinois retail customers who have not chosen an alternative retail electric supplier, the transmission rate is collected through a rider mechanism. This rate is not directly charged to Missouri retail customers because the MoPSC includes transmission-related costs in setting bundled retail rates in Missouri.

In our Missouri and Illinois retail natural gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through PGA clauses.

Ameren, UE and Genco are affected by changes in market prices for natural gas to the extent that they must purchase natural gas to run CTs. These companies have structured various supply agreements to maintain access to multiple gas pools and supply basins, and to minimize the impact to their financial statements. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk under Part II, Item 7A, below for additional information. Also see Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report for additional information on the cost recovery mechanisms discussed above.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk is the risk of changes in value of a physical asset or a financial instrument, derivative or nonderivative, caused by fluctuations in market variables such as interest rates, commodity prices, and equity security prices. A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset. The following discussion of our risk management activities includes forward-looking statements that involve risks and uncertainties. Actual results could differ materially from those projected in the forward-looking statements. We handle market risks in accordance with established policies, which may include entering into various derivative transactions. In the normal course of business, we also face risks that are either nonfinancial or nonquantifiable. Such risks, principally business, legal and operational risks, are not part of the following discussion.

Our risk management objective is to optimize our physical generating assets and to pursue market opportunities within prudent risk parameters. Our risk management policies are set by a risk management steering committee, which is composed of senior-level Ameren officers.

Interest Rate Risk

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

- long-term and short-term variable-rate debt;
- fixed-rate debt;
- auction-rate long-term debt; and
- defined pension and postretirement benefit plans.

We manage our interest rate exposure by controlling the amount of debt instruments we have within our total capitalization portfolio and by monitoring the effects of market changes in interest rates. For defined pension and postretirement benefit plans, we control the duration and portfolio mix of our plan assets.

The following table presents the estimated increase in our annual interest expense and decrease in net income if interest rates were to increase by 1% on variable-rate debt outstanding at December 31, 2010:

	Interest Expense	Net Income[(a)]
Ameren[(b)]	$ 10	$ (6)
UE	2	(1)

AIC	(c)	(c)
Genco	2	(1)

(a) Calculations are based on an effective tax rate of 38%.
(b) Includes intercompany eliminations.
(c) Less than $1 million.

The estimated changes above do not consider the potential reduced overall economic activity that would exist in such an environment. In the event of a significant change in interest rates, management would probably act to further mitigate our exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, this sensitivity analysis assumes no change in our financial structure.

Credit Risk

Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted. Exchange-traded contracts are supported by the financial and credit quality of the clearing members of the respective exchanges and have nominal credit risk. In all other transactions, we are exposed to credit risk in the event of nonperformance by the counterparties to the transaction. See Note 7 Derivative Financial Instruments under Part II, Item 8, of this report for information on the potential loss on counterparty exposure as of December 31, 2010.

Our revenues are primarily derived from sales or delivery of electricity and natural gas to customers in Missouri and Illinois. Our physical and financial instruments are subject to credit risk consisting of trade accounts receivables and executory contracts with market risk exposures. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups who make up our customer base. At December 31, 2010, no nonaffiliated customer represented more than 10%, in the aggregate, of our accounts receivable. The risk associated with AIC s electric and natural gas trade receivables is also mitigated by a rate adjustment mechanism that allows AIC to recover the difference between its actual bad debt expense under GAAP and the bad debt expense included in its base rates. UE and AIC continue to monitor the impact of increasing rates on customer collections. UE and AIC make adjustments to their allowance for doubtful accounts as deemed necessary to ensure that such allowances are adequate to cover estimated uncollectible customer account balances.

Ameren, UE, AIC and Genco may have credit exposure associated with off-system or wholesale purchase and sale activity with nonaffiliated companies. At December 31, 2010, Ameren s, UE s, AIC s and Genco s combined credit exposure to nonaffiliated non-investment-grade trading counterparties was $3 million, net of collateral (2009 $2 million). We establish credit limits for these counterparties and monitor the appropriateness of these limits on an ongoing basis through a credit risk management program. It involves daily exposure reporting to senior management, master trading and netting agreements, and credit support, such as letters of credit and parental guarantees. We also analyze each counterparty s financial condition before we enter into sales, forwards, swaps, futures or option contracts, and we monitor counterparty exposure associated with our leveraged lease. We estimate our credit exposure to MISO associated with the MISO Energy and Operating Reserves Market to be $53 million at December 31, 2010 (2009 $13 million).

Equity Price Risk

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, including the rate of return on plan assets. Ameren manages plan assets in accordance with the prudent investor guidelines contained in ERISA. Ameren s goal is to ensure that sufficient funds are available to provide the benefits at the time they are payable and also to maximize total return on plan assets and minimize expense volatility consistent with its tolerance for risk. Ameren delegates investment management to specialists. Where appropriate, Ameren provides the investment manager with guidelines that specify allowable and 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. Projected rates of return for each asset class were estimated after an analysis of historical experience, future expectations, and the volatility of the various asset classes. After considering the target asset allocation for each asset class, we adjusted the overall expected rate of return for the portfolio for historical and expected experience of active portfolio

management results compared with benchmark returns, and for the effect of expenses paid from plan assets.

In future years, the costs of such plans reflected in net income, OCI, or regulatory assets, and cash contributions to the plans could increase materially, without pension and postretirement asset portfolio investment returns equal to or in excess of our 2011 assumed return on plan assets of 8% and 7.75%, respectively.

UE also maintains a trust fund, as required by the NRC and Missouri law, to fund certain costs of nuclear plant decommissioning. As of December 31, 2010, this fund was invested primarily in domestic equity securities (68%) and debt securities (32%). It totaled $337 million (2009 $293 million). By maintaining a portfolio that includes long-term equity investments, UE seeks to maximize the returns to be used to fund nuclear decommissioning costs within acceptable parameters of risk. However, the equity securities included in the portfolio are exposed to price fluctuations in equity markets. The debt securities are exposed to changes in interest rates. UE actively monitors the portfolio by benchmarking the performance of its investments against certain indices and by maintaining and periodically reviewing established target allocation percentages of the assets of the trust to various investment options. UE s exposure to equity price market risk is in large part mitigated, because UE is currently allowed to recover its decommissioning costs, which would include unfavorable investment results, through electric rates.

Commodity Price Risk

We are exposed to changes in market prices for electricity, emission allowances, fuel, and natural gas.

Ameren s, UE s and Genco s risks of changes in prices for power sales are partially hedged through sales agreements. Merchant Generation also seeks to sell power forward to wholesale, municipal, and industrial customers to limit exposure to changing prices. We also attempt to mitigate financial risks through risk management programs and policies, which include forward-hedging programs, and the use of derivative financial instruments (primarily forward contracts, futures contracts, option contracts, and financial swap contracts). However, a portion of the generation capacity of Ameren, UE and Genco is not contracted through physical or financial hedge arrangements and is therefore exposed to volatility in market prices.

The following table shows how our earnings might decrease if power prices were to decrease by 1% on unhedged economic generation for 2011 through 2014:

	Net Income[a]
Ameren[b]	$ (17)
UE	(c)
Genco	(14)

(a) Calculations are based on an effective tax rate of 38%.
(b) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(c) Less than $1 million.

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Ameren s forward-hedging power programs include the use of derivative financial swap contracts. These swap contracts financially settle a fixed price against a floating price. The floating price is typically the realized, or settled, price at a liquid regional hub at some forward period of time. Ameren controls the use of derivative financial swap contracts with volumetric and correlation limits that are intended to mitigate any material adverse financial impact. Historically, Ameren has utilized swaps that settle against the Cinergy Hub MISO locational marginal pricing. This hub had traditionally been the most liquid location, with a strong correlation to the pricing that was realized at our generating locations. As of December 31, 2011, MISO intends to stop publishing Cinergy Hub pricing. As a result, Ameren will pursue financial hedging at the next best available regional location with sufficient liquidity. Ameren does not expect any material adverse financial impact to the outcomes of its forward-hedging programs as a result of this change. Ameren will continue to pursue the best available options to fix pricing for the output of its generating units.

Ameren also uses its portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns. Due to our physical presence in the market, we are able to identify and pursue opportunities, which can generate additional returns through portfolio management and trading activities. All of this activity is performed within a controlled risk management process. We establish value at risk (VaR) and stop-loss limits that are intended to prevent any negative material financial impact.

We manage risks associated with changing prices of fuel for generation using techniques similar to those used to manage risks associated with changing market prices for electricity.

Most Ameren, UE and Genco fuel supply contracts are physical forward contracts. Merchant Generation does not have the ability to pass through higher fuel costs to its customers for electric operations with the exception of an immaterial percentage of the output that has been contracted with a fuel cost pass through. Prior to March 2009, UE did not have this ability either except through a general rate proceeding. The MoPSC granted UE permission to put a FAC in place beginning March 1, 2009. UE remains exposed to 5% of changes, greater or less than the amounts set in base rates, in its fuel and purchased power costs, net of off-system revenues.

Ameren, UE and Genco have entered into long-term contracts with various suppliers to purchase coal to manage their exposure to fuel prices. The coal hedging strategy is intended to secure a reliable coal supply while reducing exposure to commodity price volatility. Price and volumetric risk mitigation is accomplished primarily through periodic bid procedures, whereby the amount of coal purchased is determined by the current market prices and the minimum and maximum coal purchase guidelines for the given year. Ameren, UE and Genco generally purchase coal up to five years in advance, but they may purchase coal beyond five years to take advantage of

favorable deals or market conditions. The strategy also allows for the decision not to purchase coal to avoid unfavorable market conditions. UE has an ongoing need for coal to serve its native load customers and pursues a price hedging strategy consistent with this requirement. Merchant Generation s forward coal requirements are dependent on the volume of power sales that have been contracted. As such, Merchant Generation strives to achieve increased margin certainty by aligning its fuel purchases with their power sales.

Transportation costs for coal and natural gas can be a significant portion of fuel costs. Ameren, UE and Genco typically hedge coal transportation forward to provide supply certainty and to mitigate transportation price volatility. Natural gas transportation expenses for Ameren s gas distribution utility companies and the gas-fired generation units of Ameren, UE and Genco are regulated by FERC through approved tariffs governing the rates, terms, and conditions of transportation and storage services. Certain firm transportation and storage capacity agreements held by the Ameren Companies include rights to extend the contracts prior to the termination of the primary term. Depending on our competitive position, we are able in some instances to negotiate discounts to these tariff rates for our requirements.

In addition, coal and coal transportation costs are sensitive to the price of diesel fuel as a result of rail freight fuel surcharges. If diesel fuel costs were to increase or decrease by $0.25 a gallon, Ameren s fuel expense could increase or decrease by $12 million annually (UE $7 million, Genco $4 million). As of December 31, 2010, Ameren had a price cap for approximately 89% of expected fuel surcharges in 2011.

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

With regard to exposure for commodity price risk for nuclear fuel, UE has fixed-priced, base-price-with-escalation, and market-priced agreements. It uses inventories to provide some price hedge to fulfill its Callaway nuclear plant needs for uranium, conversion and enrichment. There is no fuel reloading or planned maintenance outage scheduled for 2012 and 2015. UE has price hedges (including inventories) for approximately 83% of its 2011 to 2014 nuclear fuel requirements.

Nuclear fuel market prices remain subject to an unpredictable supply and demand environment. UE has continued to follow a strategy of managing its inventory of nuclear fuel as an inherent price hedge. New long-term uranium contracts are almost exclusively market-price-related with an escalating price floor. New long-term enrichment contracts usually have a base-price-with-escalation price mechanism, and may also have either a

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market-price-related component or market-based price re-benchmarking. UE expects to enter into additional contracts from time to time in order to supply nuclear fuel during the expected life of the Callaway nuclear plant, at prices that cannot now be accurately predicted. Unlike the electricity and natural gas markets, nuclear fuel markets have somewhat limited financial instruments available for price hedging, so most hedging is done through inventories and forward contracts, if they are available.

With regard to the electric generating operations for Ameren, UE and Genco that are exposed to changes in market prices for natural gas used to run CTs, the natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas while minimizing costs. We optimize transportation and storage options and price risk by structuring supply agreements to maintain access to multiple gas pools and supply basins.

Through the market allocation process, UE, AIC and Genco have been granted FTRs associated with the MISO Energy and Operating Reserves Market. In addition, Marketing Company has acquired FTRs for its participation in the PJM-Northern Illinois market. The FTRs are intended

to mitigate expected electric transmission congestion charges related to the physical electricity business. Depending on the congestion and prices at various points on the electric transmission grid, FTRs could result in either charges or credits. Complex grid modeling tools are used to determine which FTRs to nominate in the FTR allocation process. There is a risk of incorrectly modeling the amount of FTRs needed, and there is the potential that the FTRs could be ineffective in mitigating transmission congestion charges.

With regard to UE s and AIC s electric and natural gas distribution businesses, exposure to changing market prices is in large part mitigated by the fact that there are cost recovery mechanisms in place. These cost recovery mechanisms allow UE and AIC to pass on to retail customers prudently incurred fuel, purchased power and gas supply costs. UE s and AIC s strategy is designed to reduce the effect of market fluctuations for our regulated customers. The effects of price volatility cannot be eliminated. However, procurement strategies involve risk management techniques and instruments similar to those outlined earlier, as well as the management of physical assets.

The following table presents, as of December 31, 2010, the percentages of the projected required supply of coal and coal transportation for our coal-fired power plants, nuclear fuel for UE s Callaway nuclear plant, natural gas for our CTs and retail distribution, as appropriate, and purchased power needs of AIC, which does not own generation, that are price-hedged over the five-year period 2011 through 2015. The projected required supply of these commodities could be significantly affected by changes in our assumptions for such matters as customer demand for our electric generation and our electric and natural gas distribution services, generation output, and inventory levels, among other matters.

	2011	2012	2013 2015
Ameren[(a)]:			
Coal	94%	55%	11%
Coal transportation	100	75	28
Nuclear fuel	98	84	78
Natural gas for generation	40	2	-
Natural gas for distribution[(b)]	89	39	19
Purchased power for AIC[(c)]	78	56	8
UE:			
Coal	95%	59%	16%
Coal transportation	100	56	38
Nuclear fuel	98	84	78
Natural gas for generation	30	1	-
Natural gas for distribution[(b)]	90	35	19
AIC:			
Natural gas for distribution[(b)]	89%	39%	19%
Purchased power[(c)]	78	56	8
Genco:			
Coal	93%	49%	4%
Coal transportation	100	99	9
Natural gas for generation	84	-	-

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Represents the percentage of natural gas price-hedged for peak winter season of November through March. The year 2011 represents January 2011 through March 2011. The year 2012 represents November 2011 through March 2012. This continues each successive year through March 2015.
(c) Represents the percentage of purchased power price-hedged for fixed-price residential and small commercial customers with less than one megawatt of demand. Larger customers are purchasing power from the competitive markets. See Note 2 Rate and Regulatory Matters and Note 15 Commitments and Contingencies under Part II, Item 8, of this report for a discussion of the Illinois power procurement process and for additional information on AIC s purchased power commitments.

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The following table shows how our total fuel expense might increase and how our net income might decrease if coal and coal transportation costs were to increase by 1% on any requirements not currently covered by fixed-price contracts for the five-year period 2011 through 2015:

	Coal		Coal Transportation	
	Fuel Expense	Net Income[(a)]	Fuel Expense	Net Income[(a)]
Ameren[(b)(c)]	$ 12	$ (7)	$ 12	$ (7)
UE[(c)]	1	(d)	1	(d)
Genco	8	(5)	9	(6)

(a) Calculations are based on an effective tax rate of 38%.
(b) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(c) Includes the impact of the FAC
(d) Less than $1 million.

With regard to our exposure for commodity price risk for construction and maintenance activities, Ameren is exposed to changes in market prices for metal commodities and labor availability.

See Supply for Electric Power under Part I, Item 1, of this report for the percentages of our historical needs satisfied by coal, nuclear power, natural gas, hydroelectric power, and oil. Also see Note 15 Commitments and Contingencies under Part II, Item 8, of this report for additional information.

Fair Value of Contracts

We use derivatives principally to manage the risk of changes in market prices for natural gas, coal, diesel, electricity, uranium, and emission allowances. Such price fluctuations may cause the following:

- an unrealized appreciation or depreciation of our contracted commitments to purchase or sell when purchase or sale prices under the commitments are compared with current commodity prices;
- market values of coal, natural gas, and uranium inventories or emission allowances that differ from the cost of those commodities in inventory; and
- actual cash outlays for the purchase of these commodities that differ from anticipated cash outlays.

The derivatives that we use to hedge these risks are governed by our risk management policies for forward contracts, futures, options, and swaps. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The goal of the hedging program is generally to mitigate financial risks while ensuring that sufficient volumes are available to meet our requirements. Contracts we enter into as part of our risk management program may be settled financially, settled by physical delivery, or net settled with the counterparty. See Note 7 Derivative Financial Instruments under Part II, Item 8, of this report for additional information.

The following table presents the favorable (unfavorable) changes in the fair value of all derivative contracts marked-to-market during the year ended December 31, 2010. We use various methods to determine the fair value of our contracts. In accordance with hierarchy levels outlined in authoritative accounting guidance, the sources we used to determine the fair value of these contracts were active quotes (Level 1), inputs corroborated by market data (Level 2), and other modeling and valuation methods that are not corroborated by market data (Level 3). All of these contracts have maturities of less than five years.

	Ameren[(a)]	UE	AIC	Genco
Fair value of contracts at beginning of year, net	$ 17	$ 16	$ (483)	$ 21
Contracts realized or otherwise settled during the period	(20)	(2)	169	(9)
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-
Fair value of new contracts entered into during the period	2	4	(19)	3

Other changes in fair value		(78)		(7)		(160)		4
Fair value of contracts outstanding at end of year, net	$	(79)	$	11	$	(493)	$	19

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

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The following table presents maturities of derivative contracts as of December 31, 2010, based on the hierarchy levels used to determine the fair value of the contracts:

Sources of Fair Value	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Ameren:					
Level 1	$ (9)	$ (7)	$ (2)	$ -	$ (18)
Level 2[(a)]	(2)	-	-	-	(2)
Level 3[(b)]	(21)	(29)	(9)	-	(59)
Total	$ (32)	$ (36)	$ (11)	$ -	$ (79)
UE:					
Level 1	$ (3)	$ (4)	$ (2)	$ -	$ (9)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	14	7	(1)	-	20
Total	$ 11	$ 3	$ (3)	$ -	$ 11
AIC:					
Level 1	$ (4)	$ (3)	$ -	$ -	$ (7)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(247)	(230)	(9)	-	(486)
Total	$ (251)	$ (233)	$ (9)	$ -	$ (493)
Genco:					
Level 1	$ (1)	$ -	$ -	$ -	$ (1)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	13	7	-	-	20
Total	$ 12	$ 7	$ -	$ -	$ 19

(a) Principally fixed-price vs. floating over-the-counter power swaps, power forwards, and fixed price vs. floating over-the-counter natural gas swaps.
(b) Principally power forward contract values based on a Black-Scholes model that includes information from external sources and our estimates. Level 3 also includes option contract values based on our estimates.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.
Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders

of Ameren Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

St. Louis, Missouri

February 24, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders

of Union Electric Company:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Union Electric Company at December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

St. Louis, Missouri

February 24, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders

of Ameren Illinois Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Ameren Illinois Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

St. Louis, Missouri

February 24, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder

of Ameren Energy Generating Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Ameren Energy Generating Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

St. Louis, Missouri

February 24, 2011

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AMEREN CORPORATION

CONSOLIDATED STATEMENT OF INCOME

(In millions, except per share amounts)

	Year Ended December 31, 2010	2009	2008
Operating Revenues:			
Electric	**$ 6,521**	$ 5,940	$ 6,387
Gas	**1,117**	1,195	1,482
Total operating revenues	**7,638**	7,135	7,869
Operating Expenses:			
Fuel	**1,323**	1,141	1,275
Purchased power	**1,106**	909	1,210
Gas purchased for resale	**669**	749	1,057
Other operations and maintenance	**1,821**	1,768	1,862
Goodwill and other impairment losses	**589**	7	14
Depreciation and amortization	**765**	725	685
Taxes other than income taxes	**449**	420	404
Total operating expenses	**6,722**	5,719	6,507
Operating Income	**916**	1,416	1,362
Other Income and Expenses:			
Miscellaneous income	**90**	71	80
Miscellaneous expense	**33**	23	31
Total other income	**57**	48	49
Interest Charges	**497**	508	440
Income Before Income Taxes	**476**	956	971
Income Taxes	**325**	332	327
Net Income	**151**	624	644
Less: Net Income Attributable to Noncontrolling Interests	**12**	12	39
Net Income Attributable to Ameren Corporation	**$ 139**	$ 612	$ 605
Earnings per Common Share Basic and Diluted	**$ 0.58**	$ 2.78	$ 2.88
Dividends per Common Share	**$ 1.54**	$ 1.54	$ 2.54
Average Common Shares Outstanding	**238.8**	220.4	210.1

The accompanying notes are an integral part of these consolidated financial statements.

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AMEREN CORPORATION

CONSOLIDATED BALANCE SHEET

(In millions, except per share amounts)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 545**	$ 622
Accounts receivable trade (less allowance for doubtful accounts of $23 and $24, respectively)	**500**	424
Unbilled revenue	**406**	367
Miscellaneous accounts and notes receivable	**231**	318
Materials and supplies	**707**	782
Mark-to-market derivative assets	**129**	121
Current regulatory assets	**267**	110
Other current assets	**109**	98
Total current assets	**2,894**	2,842
Property and Plant, Net	**17,853**	17,610
Investments and Other Assets:		
Nuclear decommissioning trust fund	**337**	293
Goodwill	**411**	831
Intangible assets	**7**	129
Regulatory assets	**1,259**	1,342
Other assets	**754**	655
Total investments and other assets	**2,768**	3,250
TOTAL ASSETS	**$ 23,515**	$ 23,702
LIABILITIES AND EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 155**	$ 204
Short-term debt	**269**	20
Accounts and wages payable	**651**	694
Taxes accrued	**63**	54
Interest accrued	**107**	110
Customer deposits	**100**	101
Mark-to-market derivative liabilities	**161**	109
Current regulatory liabilities	**99**	82
Other current liabilities	**283**	337
Total current liabilities	**1,888**	1,711
Credit Facility Borrowings	**460**	830
Long-term Debt, Net	**6,853**	7,111
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**2,886**	2,554
Accumulated deferred investment tax credits	**90**	94
Regulatory liabilities	**1,319**	1,257
Asset retirement obligations	**475**	429

Pension and other postretirement benefits	**1,045**	1,165
Other deferred credits and liabilities	**615**	491
Total deferred credits and other liabilities	**6,430**	5,990
Commitments and Contingencies (Notes 2, 10, 14 and 15)		
Ameren Corporation Stockholders Equity:		
Common stock, $.01 par value, 400.0 shares authorized shares outstanding of 240.4 and 237.4, respectively	**2**	2
Other paid-in capital, principally premium on common stock	**5,520**	5,412
Retained earnings	**2,225**	2,455
Accumulated other comprehensive loss	**(17)**	(13)
Total Ameren Corporation stockholders equity	**7,730**	7,856
Noncontrolling Interests	**154**	204
Total equity	**7,884**	8,060
TOTAL LIABILITIES AND EQUITY	**$ 23,515**	$ 23,702

The accompanying notes are an integral part of these consolidated financial statements.

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AMEREN CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS

(In millions)

	Year Ended December 31, 2010	2009	2008
Cash Flows From Operating Activities:			
Net income	**$ 151**	$ 624	$ 644
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss on goodwill and other impairments	**589**	7	14
Net mark-to-market gain on derivatives	**(15)**	(23)	(3)
Depreciation and amortization	**783**	748	705
Amortization of nuclear fuel	**54**	53	37
Amortization of debt issuance costs and premium/discounts	**23**	25	20
Deferred income taxes and investment tax credits, net	**302**	402	167
Allowance for equity funds used during construction	**(52)**	(36)	(28)
Other	**40**	17	14
Changes in assets and liabilities:			
Receivables	**(85)**	21	12
Materials and supplies	**78**	67	(100)
Accounts and wages payable	**27**	(42)	57
Taxes accrued	**9**	-	(30)
Assets, other	**(109)**	(66)	83
Liabilities, other	**71**	99	110
Pension and other postretirement benefits	**(5)**	(9)	(4)
Counterparty collateral, net	**(73)**	(17)	(25)
Taum Sauk insurance recoveries, net of costs	**54**	107	(149)
Net cash provided by operating activities	**1,842**	1,977	1,524
Cash Flows From Investing Activities:			
Capital expenditures	**(1,031)**	(1,704)	(1,896)
Nuclear fuel expenditures	**(90)**	(80)	(173)
Purchases of securities nuclear decommissioning trust fund	**(271)**	(383)	(520)
Sales of securities nuclear decommissioning trust fund	**256**	380	497
Other	**24**	(2)	(5)
Net cash used in investing activities	**(1,112)**	(1,789)	(2,097)
Cash Flows From Financing Activities:			
Dividends on common stock	**(368)**	(338)	(534)
Dividends paid to noncontrolling interest holders	**(8)**	(21)	(40)
Capital issuance costs	**(15)**	(65)	(12)
Short-term and credit facility borrowings, net	**(121)**	(324)	(298)
Redemptions, repurchases, and maturities:			
Long-term debt	**(310)**	(631)	(842)
Preferred stock	**(52)**	-	(16)
Issuances:			
Common stock	**80**	634	154
Long-term debt	**-**	1,021	1,879
Generator advances received for construction, net of repayments	**(13)**	66	19

Net cash provided by (used in) financing activities		**(807)**		342		310
Net change in cash and cash equivalents		**(77)**		530		(263)
Cash and cash equivalents at beginning of year		**622**		92		355
Cash and cash equivalents at end of year	**$**	**545**	$	622	$	92
Cash Paid (Refunded) During the Year:						
Interest (net of $34, $40, and $41 capitalized, respectively)	**$**	**494**	$	485	$	409
Income taxes, net		**(92)**		9		106

The accompanying notes are an integral part of these consolidated financial statements.

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AMEREN CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

(In millions)

	December 31, 2010	2009	2008
Common Stock:			
Beginning of year	**$ 2**	$ 2	$ 2
Shares issued	**-**	-	-
Common stock, end of year	**2**	2	2
Other Paid-in Capital:			
Beginning of year	**5,412**	4,780	4,604
Shares issued (less issuance costs of $-, $17, and $-, respectively)	**80**	617	154
Stock-based compensation cost	**14**	15	22
Regulatory recovery of prior-period common stock issuance costs	**14**	-	-
Other paid-in capital, end of year	**5,520**	5,412	4,780
Retained Earnings:			
Beginning of year	**2,455**	2,181	2,110
Net income attributable to Ameren Corporation	**139**	612	605
Dividends	**(368)**	(338)	(534)
Other	**(1)**	-	-
Retained earnings, end of year	**2,225**	2,455	2,181
Accumulated Other Comprehensive Income (Loss):			
Derivative financial instruments, beginning of year	**10**	48	9
Change in derivative financial instruments	**(10)**	(38)	39
Derivative financial instruments, end of year	**-**	10	48
Deferred retirement benefit costs, beginning of year	**(23)**	(43)	25
Change in deferred retirement benefit costs	**6**	20	(68)
Deferred retirement benefit costs, end of year	**(17)**	(23)	(43)
Total accumulated other comprehensive income (loss), end of year	**(17)**	(13)	5
Total Ameren Corporation Stockholders Equity	**$ 7,730**	$ 7,856	$ 6,968
Noncontrolling Interests:			
Beginning of year	**204**	211	218
Net income attributable to noncontrolling interest holders	**12**	12	39
Dividends paid to noncontrolling interest holders	**(8)**	(21)	(40)
Redemptions of preferred stock	**(52)**	-	-
Other	**(2)**	2	(6)

Noncontrolling interests, end of year	**154**	204	211
Total Equity	**$ 7,884**	$ 8,060	$ 7,179
Comprehensive Income, Net of Taxes:			
Net income	**$ 151**	$ 624	$ 644
Unrealized net gain (loss) on derivative hedging instruments, net of income taxes (benefit) of $(1), $78, and $65, respectively	**(2)**	103	116
Reclassification adjustments for derivative (gains) included in net income, net of income taxes of $5, $82, and $43, respectively	**(8)**	(112)	(77)
Reclassification adjustment due to implementation of FAC, net of income taxes of $-, $18, and $-, respectively	**-**	(29)	-
Pension and other postretirement activity, net of income taxes (benefit) of $6, $22, and $(45), respectively	**4**	22	(75)
Total Comprehensive Income, Net of Taxes	**$ 145**	$ 608	$ 608
Comprehensive income attributable to noncontrolling interests	**10**	14	33
Total Comprehensive Income Attributable to Ameren Corporation, Net of Taxes	**$ 135**	$ 594	$ 575
Common stock shares at beginning of year	**237.4**	212.3	208.3
Shares issued	**3.0**	25.1	4.0
Common stock shares at end of year	**240.4**	237.4	212.3

The accompanying notes are an integral part of these consolidated financial statements.

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UNION ELECTRIC COMPANY

STATEMENT OF INCOME

(In millions)

	Year Ended December 31, 2010	2009	2008
Operating Revenues:			
Electric	**$ 3,030**	$ 2,700	$ 2,756
Gas	**166**	170	201
Other	**1**	4	3
Total operating revenues	**3,197**	2,874	2,960
Operating Expenses:			
Fuel	**635**	593	672
Purchased power	**162**	124	160
Gas purchased for resale	**91**	97	123
Other operations and maintenance	**931**	880	922
Depreciation and amortization	**382**	357	329
Taxes other than income taxes	**285**	257	240
Total operating expenses	**2,486**	2,308	2,446
Operating Income	**711**	566	514
Other Income and Expenses:			
Miscellaneous income	**83**	63	62
Miscellaneous expense	**13**	7	9
Total other income	**70**	56	53
Interest Charges	**213**	229	193
Income Before Income Taxes and Equity in Income of Unconsolidated Investment	**568**	393	374
Income Taxes	**199**	128	134
Income Before Equity in Income of Unconsolidated Investment	**369**	265	240
Equity in Income of Unconsolidated Investment, Net of Taxes	**-**	-	11
Net Income	**369**	265	251
Preferred Stock Dividends	**5**	6	6
Net Income Available to Common Stockholder	**$ 364**	$ 259	$ 245

The accompanying notes as they relate to UE are an integral part of these financial statements.

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UNION ELECTRIC COMPANY

BALANCE SHEET

(In millions, except per share amounts)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 202**	$ 267
Accounts receivable trade (less allowance for doubtful accounts of $8 and $6, respectively)	**217**	154
Accounts receivable affiliates	**6**	22
Unbilled revenue	**159**	127
Miscellaneous accounts and notes receivable	**116**	199
Materials and supplies	**341**	346
Current regulatory assets	**179**	63
Other current assets	**55**	50
Total current assets	**1,275**	1,228
Property and Plant, Net	**9,775**	9,585
Investments and Other Assets:		
Nuclear decommissioning trust fund	**337**	293
Intangible assets	**2**	35
Regulatory assets	**694**	683
Other assets	**421**	395
Total investments and other assets	**1,454**	1,406
TOTAL ASSETS	**$ 12,504**	$ 12,219
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 5**	$ 4
Accounts and wages payable	**326**	336
Accounts payable affiliates	**75**	132
Taxes accrued	**76**	21
Interest accrued	**63**	63
Current accumulated deferred income taxes, net	**43**	12
Other current liabilities	**112**	115
Total current liabilities	**700**	683
Long-term Debt, Net	**3,949**	4,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**1,908**	1,660
Accumulated deferred investment tax credits	**78**	79
Regulatory liabilities	**766**	865
Asset retirement obligations	**363**	331
Pension and other postretirement benefits	**369**	400
Other deferred credits and liabilities	**218**	126

Total deferred credits and other liabilities	**3,702**	3,461
Commitments and Contingencies (Notes 2, 10, 14 and 15)		
Stockholders Equity:		
Common stock, $5 par value, 150.0 shares authorized 102.1 shares outstanding	**511**	511
Other paid-in capital, principally premium on common stock	**1,555**	1,555
Preferred stock not subject to mandatory redemption	**80**	113
Retained earnings	**2,007**	1,878
Total stockholders equity	**4,153**	4,057
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 12,504**	$ 12,219

The accompanying notes as they relate to UE are an integral part of these financial statements.

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UNION ELECTRIC COMPANY

STATEMENT OF CASH FLOWS

(In millions)

	Year Ended December 31, 2010	2009	2008
Cash Flows From Operating Activities:			
Net income	**$ 369**	$ 265	$ 251
Adjustments to reconcile net income to net cash provided by operating activities:			
Net mark-to-market (gain) loss on derivatives	**(1)**	(29)	29
Depreciation and amortization	**382**	357	329
Amortization of nuclear fuel	**54**	53	37
Amortization of debt issuance costs and premium/discounts	**4**	10	6
Deferred income taxes and investment tax credits, net	**228**	276	89
Allowance for equity funds used during construction	**(50)**	(33)	(27)
Other	**20**	-	(5)
Changes in assets and liabilities:			
Receivables	**(56)**	(58)	60
Materials and supplies	**7**	(2)	(32)
Accounts and wages payable	**(17)**	16	(89)
Taxes accrued	**55**	1	(61)
Assets, other	**(145)**	(58)	42
Liabilities, other	**77**	69	63
Pension and other postretirement benefits	**(3)**	(2)	-
Taum Sauk insurance recoveries, net of costs	**54**	107	(149)
Net cash provided by operating activities	**978**	972	543
Cash Flows From Investing Activities:			
Capital expenditures	**(608)**	(872)	(874)
Nuclear fuel expenditures	**(90)**	(80)	(173)
Proceeds from intercompany note receivable	**-**	-	36
Purchases of securities nuclear decommissioning trust fund	**(271)**	(383)	(520)
Sales of securities nuclear decommissioning trust fund	**256**	380	497
Other	**7**	-	1
Net cash used in investing activities	**(706)**	(955)	(1,033)
Cash Flows From Financing Activities:			
Dividends on common stock	**(235)**	(175)	(264)
Dividends on preferred stock	**(5)**	(6)	(6)
Capital issuance costs	**(4)**	(14)	(5)
Short-term debt, net	**-**	(251)	169
Intercompany note payable Ameren, net	**-**	(92)	92
Redemptions, repurchases, and maturities:			
Long-term debt	**(70)**	(4)	(382)
Preferred stock	**(33)**	-	-
Issuances of long-term debt	**-**	349	699
Capital contribution from parent	**-**	436	-
Other	**10**	7	2
Net cash provided by (used in) financing activities	**(337)**	250	305

Net change in cash and cash equivalents	**(65)**	267	(185)
Cash and cash equivalents at beginning of year	**267**	-	185
Cash and cash equivalents at end of year	**$ 202**	$ 267	$ -
Cash Paid (Refunded) During the Year:			
Interest (net of $26, $23, and $19 capitalized, respectively)	**$ 213**	$ 212	$ 177
Income taxes, net	**(106)**	(208)	130

The accompanying notes as they relate to UE are an integral part of these financial statements.

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UNION ELECTRIC COMPANY

STATEMENT OF STOCKHOLDERS EQUITY

(In millions)

	December 31, 2010	2009	2008
Common Stock	**$ 511**	$ 511	$ 511
Other Paid-in Capital:			
Beginning of year	**1,555**	1,119	1,119
Capital contribution from parent	**-**	436	-
Other paid-in capital, end of year	**1,555**	1,555	1,119
Preferred Stock Not Subject to Mandatory Redemption:			
Beginning balance	**113**	113	113
Redemptions	**(33)**	-	-
Preferred stock not subject to mandatory redemption, end of year	**80**	113	113
Retained Earnings:			
Beginning of year	**1,878**	1,794	1,855
Net income	**369**	265	251
Common stock dividends	**(235)**	(175)	(264)
Preferred stock dividends	**(5)**	(6)	(6)
Dividend-in-kind to Ameren	**-**	-	(42)
Retained earnings, end of year	**2,007**	1,878	1,794
Accumulated Other Comprehensive Income:			
Beginning of year	**-**	25	3
Change in derivative financial instruments	**-**	(25)	22
Accumulated other comprehensive income, end of year	**-**	-	25
Total Stockholders Equity	**$ 4,153**	$ 4,057	$ 3,562
Comprehensive Income, Net of Taxes:			
Net income	**$ 369**	$ 265	$ 251
Unrealized net gain on derivative hedging instruments, net of income taxes of $-, $11, and $22, respectively	**-**	17	36
Reclassification adjustments for derivative (gains) included in net income, net of income taxes of $-, $8, and $9, respectively	**-**	(13)	(14)
Reclassification adjustment due to implementation of FAC, net of income taxes of $-, $18, and $-, respectively	**-**	(29)	-
Total Comprehensive Income, Net of Taxes	**$ 369**	$ 240	$ 273

The accompanying notes as they relate to UE are an integral part of these financial statements.

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AMEREN ILLINOIS COMPANY

CONSOLIDATED STATEMENT OF INCOME

(In millions)

	Year Ended December 31, 2010	2009[(a)]	2008[(a)]
Operating Revenues:			
Electric	**$ 2,061**	$ 1,965	$ 2,242
Gas	**953**	1,015	1,265
Other	**-**	4	1
Total operating revenues	**3,014**	2,984	3,508
Operating Expenses:			
Purchased power	**965**	1,048	1,405
Gas purchased for resale	**578**	642	914
Other operations and maintenance	**635**	590	653
Depreciation and amortization	**210**	216	219
Taxes other than income taxes	**128**	125	126
Total operating expenses	**2,516**	2,621	3,317
Operating Income	**498**	363	191
Other Income and Expenses:			
Miscellaneous income	**7**	12	23
Miscellaneous expense	**13**	10	12
Total other income (expense)	**(6)**	2	11
Interest Charges	**143**	153	145
Income Before Income Taxes	**349**	212	57
Income Taxes	**137**	79	16
Income from Continuing Operations	**212**	133	41
Income from Discontinued Operations, net of tax	**40**	114	52
Net Income	**252**	247	93
Preferred Stock Dividends	**4**	6	6
Net Income Available to Common Stockholder	**$ 248**	$ 241	$ 87

(a) Prior period has been adjusted to reflect the AIC Merger as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to AIC are an integral part of these consolidated financial statements.

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AMEREN ILLINOIS COMPANY

CONSOLIDATED BALANCE SHEET

(In millions)

	December 31, 2010	December 31, 2009[a]
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 322**	$ 306
Accounts receivable trade (less allowance for doubtful accounts of $13 and $17, respectively)	**230**	199
Accounts and notes receivable affiliates	**73**	105
Unbilled revenue	**205**	189
Miscellaneous accounts and notes receivable	**44**	51
Materials and supplies	**198**	212
Current regulatory assets	**260**	174
Other current assets	**106**	63
Current assets of discontinued operations	**-**	112
Total current assets	**1,438**	1,411
Property and Plant, Net	**4,576**	4,354
Investments and Other Assets:		
Intercompany tax receivable Genco	**72**	82
Goodwill	**411**	411
Regulatory assets	**743**	944
Other assets	**166**	91
Noncurrent assets of discontinued operations	**-**	1,005
Total investments and other assets	**1,392**	2,533
TOTAL ASSETS	**$ 7,406**	$ 8,298
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 150**	$ -
Accounts and wages payable	**182**	192
Accounts payable affiliates	**82**	179
Taxes accrued	**26**	15
Customer deposits	**83**	85
Mark-to-market derivative liabilities	**82**	38
Mark-to-market derivative liabilities affiliates	**172**	127
Environmental remediation	**72**	80
Current regulatory liabilities	**76**	57
Other current liabilities	**90**	132
Current liabilities of discontinued operations	**-**	334
Total current liabilities	**1,015**	1,239
Long-term Debt, Net	**1,657**	1,847
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**724**	554
Accumulated deferred investment tax credits	**8**	10

Regulatory liabilities	**553**	391
Pension and other postretirement benefits	**413**	471
Other deferred credits and liabilities	**460**	483
Noncurrent liabilities of discontinued operations	**-**	231
Total deferred credits and other liabilities	**2,158**	2,140
Commitments and Contingencies (Notes 2, 14 and 15)		
Stockholders Equity:		
Common stock, no par value, 45.0 shares authorized 25.5 shares outstanding	**-**	-
Other paid-in capital	**1,952**	2,223
Preferred stock not subject to mandatory redemption	**62**	115
Retained earnings	**542**	709
Accumulated other comprehensive income	**20**	25
Total stockholders equity	**2,576**	3,072
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 7,406**	$ 8,298

(a) Prior period has been adjusted to reflect the AIC Merger as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to AIC are an integral part of these consolidated financial statements.

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AMEREN ILLINOIS COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

(In millions)

	Year Ended December 31,		
	2010	**2009[(a)]**	**2008[(a)]**
Cash Flows From Operating Activities:			
Net income	**$ 252**	$ 247	$ 93
Income from discontinued operations, net of tax	**(40)**	(114)	(52)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**210**	212	209
Amortization of debt issuance costs and premium/discounts	**10**	9	11
Deferred income taxes and investment tax credits, net	**161**	72	22
Other	**2**	(11)	6
Changes in assets and liabilities:			
Receivables	**(41)**	142	(25)
Materials and supplies	**14**	85	(37)
Accounts and wages payable	**(44)**	(3)	74
Taxes accrued	**11**	(11)	11
Assets, other	**(76)**	74	(35)
Liabilities, other	**32**	11	72
Pension and other postretirement benefits	**(7)**	5	(20)
Operating cash flows provided by discontinued operations	**113**	141	159
Net cash provided by operating activities	**597**	859	488
Cash Flows From Investing Activities:			
Capital expenditures	**(286)**	(356)	(345)
Advances to ATXI for construction	**(10)**	(47)	(13)
Proceeds from intercompany note receivable Genco	**45**	42	39
Other	**-**	-	(2)
Capital expenditures of discontinued operations	**(6)**	(91)	(256)
Net cash used in investing activities	**(257)**	(452)	(577)
Cash Flows From Financing Activities:			
Dividends on common stock	**(133)**	(98)	(60)
Dividends on preferred stock	**(4)**	(6)	(6)
Capital issuance costs	**(4)**	(13)	(6)
Short-term and credit facility borrowings, net	**-**	(62)	(353)
Redemptions, repurchases, and maturities:			
Long-term debt	**(40)**	(250)	(460)
Preferred stock	**(19)**	-	(16)
Issuances of long-term debt	**-**	-	880
Generator advances for construction received (refunded), net of repayments	**(23)**	56	20
Capital contribution from parent	**6**	272	-
Net financing activities provided by (used in) discontinued operations	**(107)**	(50)	104
Net cash provided by (used in) financing activities	**(324)**	(151)	103
Net change in cash and cash equivalents	**16**	256	14
Cash and cash equivalents at beginning of year	**306**	50	36

Cash and cash equivalents at end of year	**$**	**322**	$	306	$	50
Cash Paid (Refunded) During the Year:						
Interest (net of $1, $3 and $10 capitalized, respectively)	**$**	**160**	$	167	$	131
Income taxes, net		**(39)**		129		(80)
Noncash investing activity asset transfer from ATXI		**7**		29		-

(a) Prior period has been adjusted to reflect the AIC Merger as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to AIC are an integral part of these consolidated financial statements.

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AMEREN ILLINOIS COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

(In millions)

	December 31, 2010	2009[(a)]	2008[(a)]
Common Stock	**$ -**	$ -	$ -
Other Paid-in Capital:			
Beginning of year	**2,223**	1,951	1,951
Capital contribution from parent	**6**	272	-
Contribution of Ameren owned preferred stock without consideration	**33**	-	-
Transfer of AERG to parent (Notes 1 and 16)	**(310)**	-	-
Other paid-in capital, end of year	**1,952**	2,223	1,951
Preferred Stock Not Subject to Mandatory Redemption:			
Beginning balance	**115**	115	115
Redemptions	**(19)**	-	-
Contribution of Ameren owned preferred stock without consideration	**(33)**	-	-
Other	**(1)**	-	-
Preferred stock not subject to mandatory redemption, end of year	**62**	115	115
Retained Earnings:			
Beginning of year	**709**	566	539
Net income	**252**	247	93
Common stock dividends	**(133)**	(98)	(60)
Preferred stock dividends	**(4)**	(6)	(6)
Transfer of AERG to parent (Notes 1 and 16)	**(281)**	-	-
Other	**(1)**	-	-
Retained earnings, end of year	**542**	709	566
Accumulated Other Comprehensive Income:			
Deferred retirement benefit costs, beginning of year	**25**	23	30
Change in deferred retirement benefit costs	**(4)**	(4)	(1)
Change in accumulated other comprehensive income from discontinued operations	**(1)**	6	(6)
Deferred retirement benefit costs, end of year	**20**	25	23
Total accumulated other comprehensive income, end of year	**20**	25	23
Total Stockholders Equity	**$ 2,576**	$ 3,072	$ 2,655
Comprehensive Income, Net of Taxes:			
Net income	**$ 252**	$ 247	$ 93
Pension and other postretirement activity, net of income taxes (benefit) of $(2), $(2), and $(1), respectively	**(4)**	(4)	(1)
Comprehensive income from discontinued operations	**(1)**	6	(6)
Total Comprehensive Income, Net of Taxes	**$ 247**	$ 249	$ 86

(a) Prior period has been adjusted to reflect the AIC Merger as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to AIC are an integral part of these consolidated financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED STATEMENT OF INCOME (LOSS)

(In millions)

	Year Ended December 31, 2010	2009[(a)]	2008[(a)]
Operating Revenues	**$ 1,126**	$ 1,148	$ 1,422
Operating Expenses:			
Fuel	**522**	415	509
Coal contract settlement	**-**	-	(60)
Purchased power	**61**	72	97
Other operations and maintenance	**191**	226	227
Goodwill and other impairment losses	**170**	6	-
Depreciation and amortization	**98**	81	75
Taxes other than income taxes	**22**	24	23
Total operating expenses	**1,064**	824	871
Operating Income	**62**	324	551
Other Income and Expenses:			
Miscellaneous income	**1**	1	1
Miscellaneous expense	**1**	1	1
Total other income	**-**	-	-
Interest Charges	**78**	61	55
Income (Loss) Before Income Taxes	**(16)**	263	496
Income Taxes	**20**	101	182
Net Income (Loss)	**(36)**	162	314
Less: Net Income Attributable to Noncontrolling Interest	**3**	2	28
Net Income (Loss) Attributable to Ameren Energy Generating Company	**$ (39)**	$ 160	$ 286

(a) Prior period has been adjusted to include EEI as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED BALANCE SHEET

(In millions, except shares)

	December 31, 2010	2009[(a)]
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 6**	$ 6
Advances to money pool	**25**	73
Accounts receivable affiliates	**126**	129
Miscellaneous accounts and notes receivable	**19**	26
Materials and supplies	**130**	170
Mark-to-market derivative assets	**26**	22
Other current assets	**4**	2
Total current assets	**336**	428
Property and Plant, Net	**2,248**	2,337
Investments and Other Assets:		
Goodwill	**-**	65
Intangible Assets	**3**	62
Other Assets	**24**	28
TOTAL ASSETS	**$ 2,611**	$ 2,920
LIABILITIES AND EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ -**	$ 200
Current portion of note payable AIC	**-**	45
Note payable Ameren	**-**	131
Accounts and wages payable	**62**	85
Accounts payable affiliates	**23**	40
Current portion of tax payable AIC	**8**	9
Taxes accrued	**20**	17
Interest accrued	**13**	13
Mark-to-market derivative liabilities	**9**	12
Mark-to-market derivative liabilities affiliates	**5**	1
Current accumulated deferred income taxes, net	**13**	26
Other current liabilities	**12**	19
Total current liabilities	**165**	598
Credit Facility Borrowings	**100**	-
Long-term Debt, Net	**824**	823
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**253**	216
Accumulated deferred investment tax credits	**3**	4
Tax payable AIC	**72**	82
Asset retirement obligations	**74**	60
Pension and other postretirement benefits	**88**	89
Other deferred credits and liabilities	**23**	35

Total deferred credits and other liabilities	**513**	486
Commitments and Contingencies (Notes 2, 14 and 15)		
Ameren Energy Generating Company Stockholder s Equity:		
Common stock, no par value, 10,000 shares authorized 2,000 shares outstanding	**-**	-
Other paid-in capital	**649**	620
Retained earnings	**393**	432
Accumulated other comprehensive loss	**(44)**	(48)
Total Ameren Energy Generating Company stockholder s equity	**998**	1,004
Noncontrolling Interest	**11**	9
Total equity	**1,009**	1,013
TOTAL LIABILITIES AND EQUITY	**$ 2,611**	$ 2,920

(a) Prior period has been adjusted to include EEI as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

(In millions)

	Year Ended December 31,		
	2010	**2009[(a)]**	**2008[(a)]**
Cash Flows From Operating Activities:			
Net income (loss)	**$ (36)**	$ 162	$ 314
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss on goodwill and other impairments	**170**	6	-
Net mark-to-market (gain) loss on derivatives	**(8)**	(27)	24
Depreciation and amortization	**113**	106	104
Amortization of debt issuance costs and discounts	**3**	2	1
Deferred income taxes and investment tax credits, net	**19**	64	22
Other	**1**	-	(2)
Changes in assets and liabilities:			
Receivables	**10**	(13)	(22)
Materials and supplies	**42**	(12)	(34)
Accounts and wages payable	**(25)**	(19)	6
Taxes accrued	**3**	-	1
Assets, other	**7**	9	10
Liabilities, other	**(24)**	(26)	(6)
Pension and other postretirement benefits	**5**	1	3
Net cash provided by operating activities	**280**	253	421
Cash Flows From Investing Activities:			
Capital expenditures	**(95)**	(316)	(353)
Proceeds from sale of property interests	**18**	-	-
Money pool advances, net	**48**	(73)	-
Other	**-**	-	(13)
Net cash used in investing activities	**(29)**	(389)	(366)
Cash Flows From Financing Activities:			
Dividends on common stock	**-**	(43)	(221)
Dividends paid to noncontrolling interest holder	**-**	(11)	(30)
Capital issuance costs	**(4)**	(7)	(2)
Short-term and credit facility borrowings, net	**100**	-	(100)
Money pool borrowings, net	**-**	(80)	26
Redemptions of long-term debt	**(200)**	-	-
Issuances of long-term debt	**-**	249	300
Notes payable affiliates	**(176)**	31	(27)
Capital contribution from parent	**29**	-	-
Net cash provided by (used in) financing activities	**(251)**	139	(54)
Net change in cash and cash equivalents	**-**	3	1
Cash and cash equivalents at beginning of year	**6**	3	2
Cash and cash equivalents at end of year	**$ 6**	$ 6	$ 3

Cash Paid During the Year:			
Interest (net of $6, $12, and $10 capitalized, respectively)	**$ 77**	$ 58	$ 51
Income taxes, net	**1**	74	152

(a) Prior period has been adjusted to include EEI as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDER S EQUITY

(In millions)

	December 31, 2010	2009[(a)]	2008[(a)]
Common Stock	**$ -**	$ -	$ -
Other Paid-in Capital:			
Beginning of year	**620**	620	620
Capital contribution from parent	**29**	-	-
Other paid-in capital, end of year	**649**	620	620
Retained Earnings:			
Beginning of year	**432**	315	250
Net income (loss) attributable to Ameren Energy Generating Company	**(39)**	160	286
Common stock dividends	**-**	(43)	(221)
Retained earnings, end of year	**393**	432	315
Accumulated Other Comprehensive Loss:			
Derivative financial instruments, beginning of year	**(6)**	(6)	(1)
Change in derivative financial instruments	**-**	-	(5)
Derivative financial instruments, end of year	**(6)**	(6)	(6)
Deferred retirement benefit costs, beginning of year	**(42)**	(61)	(12)
Change in deferred retirement benefit costs	**4**	19	(49)
Deferred retirement benefit costs, end of year	**(38)**	(42)	(61)
Total accumulated other comprehensive loss, end of year	**(44)**	(48)	(67)
Total Ameren Energy Generating Company Stockholder s Equity	**$ 998**	$ 1,004	$ 868
Noncontrolling Interest:			
Beginning of year	**9**	16	24
Net income attributable to noncontrolling interest holder	**3**	2	28
Dividends paid to noncontrolling interest holder	**-**	(11)	(30)
Other comprehensive income (loss) attributable to noncontrolling interest holder	**(1)**	2	(6)
Noncontrolling interest, end of year	**11**	9	16
Total Equity	**$ 1,009**	**$ 1,013**	**$ 884**
Comprehensive Income (Loss), Net of Taxes:			
Net income (loss)	**$ (36)**	$ 162	$ 314
Reclassification adjustments for derivative gains included in net income, net of income taxes of $-, $-, and $3, respectively	**-**	-	(5)
	3	21	(55)

Pension and other postretirement activity, net of income taxes (benefit) of $5, $12, and $(29), respectively						
Total Comprehensive Income (Loss), Net of Taxes	**$**	**(33)**	$	183	$	254
Comprehensive income attributable to noncontrolling interest holder		**2**		4		22
Total Comprehensive Income (Loss) Attributable to Ameren Energy Generating Company, Net of Taxes	**$**	**(35)**	$	179	$	232

(a) Prior period has been adjusted to include EEI as discussed in Note 1 Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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AMEREN CORPORATION (Consolidated)

UNION ELECTRIC COMPANY

AMEREN ILLINOIS COMPANY (Consolidated)

AMEREN ENERGY GENERATING COMPANY

(Consolidated)

COMBINED NOTES TO FINANCIAL STATEMENTS

December 31, 2010

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005, administered by FERC. Ameren s primary assets are the common stock of its subsidiaries. Ameren s subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. These subsidiaries operate, as the case may be, rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois. Dividends on Ameren s common stock and the payment of other expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren s principal subsidiaries are listed below. Also see the Glossary of Terms and Abbreviations at the front of this report.

UE, or Union Electric Company, which does business as Ameren Missouri, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri. 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. It supplies electric and natural gas service to a 24,000-square-mile area in central and eastern Missouri. This area has an estimated population of 2.8 million and includes the Greater St. Louis area. UE supplies electric service to 1.2 million customers and natural gas service to 127,000 customers.

AIC, or Ameren Illinois Company, which does business as Ameren Illinois, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. AIC was created by the merger of CILCO and IP with and into CIPS. CIPS was incorporated in Illinois in 1923 and is successor to a number of companies, the oldest of which was organized in 1902. AIC supplies electric and natural gas utility service to portions of central and southern Illinois having an estimated population of 3 million in an area of 40,000 square miles. AIC supplies electric service to 1.2 million customers and natural gas service to 811,000 customers.

Genco, or Ameren Energy Generating Company, operates a merchant electric generation business in Illinois and Missouri. Genco was incorporated in Illinois
in March 2000. Genco s coal, natural gas and oil-fired electric generating facilities, are expected to have capacity of 3,437, 1,553, and 169 megawatts, respectively, at the time of the 2011 peak summer electrical demand.

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed a two-step corporate internal reorganization. The first step of the reorganization was the AIC Merger, pursuant to the terms of the agreement, dated as of April 13, 2010. Upon consummation of the AIC Merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. The AIC Merger and the distribution of AERG stock were accounted for as transactions between entities under common control. In accordance with authoritative accounting guidance, assets and liabilities transferred between entities under common control were accounted for at the historical cost basis of the common parent, Ameren, as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren s historical cost basis in AIC included purchase accounting adjustments related to Ameren s acquisition of CILCORP in 2003. AIC accounted for the AERG distribution as a spinoff. AIC transferred AERG to Ameren based on AERG s carrying value. AIC determined that the operating results of AERG qualified for discontinued operations presentation; therefore, AIC has segregated AERG s operating results and presented them separately as discontinued operations for all periods presented prior to October 1, 2010, in this report. For Ameren s financial statements, AERG s results of operation remain classified as continuing operations. See Note 16 Corporate Reorganization and Discontinued Operations for additional information.

Ameren has various other subsidiaries responsible for the marketing of power, management of commodity risks, and provision of other shared services. Ameren has an 80% ownership interest in EEI, which until February 29, 2008, was held 40% by UE and 40% by Development Company. UE reported EEI under the equity method until February 29, 2008. Effective February 29, 2008, UE s and Development Company s ownership interests in EEI were transferred to Resources Company through an internal reorganization. UE s interest in EEI was transferred at book value indirectly through a dividend to Ameren. Effective January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% stock ownership interest in EEI to Genco through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco accounted for the transfer at the historical carrying value of the parent (Ameren) as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren s historical cost basis in EEI included purchase accounting adjustments relating to Ameren s acquisition of an additional 20% ownership interest in EEI in 2004. This transfer required Genco s prior-period financial statements to be retrospectively combined for all periods presented. Consequently, Genco s prior-period consolidated financial statements reflect EEI as if it had been a subsidiary of Genco. Ameren and Genco consolidate EEI for financial reporting purposes. See Note 14 Related Party Transactions for additional information.

The financial statements of Ameren, AIC and Genco are prepared on a consolidated basis. UE does not have subsidiaries and therefore its financial statements are not consolidated. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

At December 31, 2010 and 2009, Ameren had immaterial investments in multiple affordable housing and low-income real estate development partnerships as well as an investment in a commercial real estate development partnership. Ameren has a variable interest in these investments as a limited partner. Ameren is not the primary beneficiary of these investments because Ameren does not have the power to direct matters that most significantly impact the activities of these VIE. The maximum exposure to loss as a result of these variable interests is limited to the investments in these partnerships. Ameren uses the equity method of accounting for its investments in these partnerships. See Note 14 Related Party Transactions for information about AIC s variable interest in ATXI.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) that are necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires that Ameren management 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.

Regulation

Certain Ameren subsidiaries are regulated by the MoPSC, the ICC, the NRC, and FERC. In accordance with authoritative accounting guidance regarding accounting for the effects of certain types of regulation, UE and AIC defer certain costs as assets pursuant to actions of rate regulators or the expected ability to recover such costs in rates charged to customers. UE and AIC also defer certain amounts as liabilities pursuant to actions of rate regulators or the expectation that such amounts will be returned to customers in future rates. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. See Note 2 Rate and Regulatory Matters for additional information on regulatory assets and liabilities. In addition, other costs that UE and AIC expect to recover from customers are also recorded as construction work in progress and property and plant, net. See Note 3 Property and Plant, Net.

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.

Allowance for Doubtful Accounts Receivable

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including unbilled revenue. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management s best estimate of future collections success given the existing and anticipated future collections environment. AIC has a rate mechanism that adjusts rates for bad debt expense above or below those being collected in rates.

Materials and Supplies

Materials and supplies are recorded at the lower of cost or market. Cost is determined using the average-cost method. Materials and supplies are capitalized as inventory when purchased and then expensed or capitalized as plant assets when installed, as appropriate. The following table presents a breakdown of materials and supplies for each of the Ameren Companies at December 31, 2010 and 2009:

	Ameren[(a)]	UE	AIC	Genco
2010:				
Fuel[(b)]	**$ 255**	**$ 152**	**$ -**	**$ 81**
Gas stored underground	**175**	**22**	**152**	**-**
Other materials and supplies	**277**	**167**	**46**	**49**
	$ 707	**$ 341**	**$ 198**	**$ 130**
2009:				
Fuel[(b)]	$ 315	$ 154	$ -	$ 123
Gas stored underground	183	22	161	-
Other materials and supplies	284	170	51	47
	$ 782	$ 346	$ 212	$ 170

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Consists of coal, oil, paint, propane, and tire chips.

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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, as discussed specifically below, is also capitalized as a cost of our rate-regulated assets. Interest during construction is capitalized as a cost of merchant generation assets. Maintenance expenditures, including nuclear refueling and maintenance outages, are expensed as incurred. When units of depreciable property are retired, the original costs, less salvage values, are charged to accumulated depreciation. Asset removal costs incurred by our merchant generation operations that do not constitute legal obligations are expensed as incurred. Asset removal costs accrued by our rate-regulated operations that do not constitute legal obligations are classified as a regulatory liability. See Asset Retirement Obligations below and Note 3 Property and Plant, Net, for additional 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 to the cost basis of such property. The provision for depreciation for the Ameren Companies in 2010, 2009 and 2008 ranged from 3% to 4% of the average depreciable cost.

Allowance for Funds Used During Construction

In our rate-regulated operations, we capitalize the 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, as is the 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 it 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 and other construction costs occurs when completed projects are placed in service and reflected in customer rates. The following table presents the annual allowance for funds used during construction rates that were utilized during 2010, 2009 and 2008:

	2010	2009	2008
Ameren	**8% - 9%**	6% - 9%	3% - 7%
UE	**8**	6	7
AIC	**9**	9	3

Goodwill and Intangible Assets

Goodwill. Goodwill represents the excess of the purchase price of an acquisition over the fair value of the

net assets acquired. As of December 31, 2010, Ameren s and AIC s goodwill related to its acquisition of IP in 2004 and its acquisition of CILCORP in 2003.

We evaluate goodwill for impairment as of October 31 of each year, or more frequently if events or changes in circumstances indicate that the asset might be impaired. Ameren and Genco conducted an interim goodwill impairment test in the third quarter of 2010. That test resulted in the elimination of all goodwill associated with the Merchant Generation segment at Ameren ($420 million) and Genco ($65 million). This goodwill was associated with the acquisition of CILCORP and Medina Valley in 2003 and an additional 20% interest in EEI in 2004. See Note 17 Goodwill and Other Asset Impairments for additional information.

Intangible Assets. We evaluate intangible assets for impairment if events or changes in circumstances indicate that their carrying amount might be impaired. Ameren s, UE s and Genco s intangible assets at December 31, 2010, and 2009, consisted of emission allowances. During 2010, Ameren and Genco recorded a noncash pretax impairment charge relating to SO_2 emission allowances of $68 million and $41 million, respectively. UE recorded a $23 million impairment of its SO_2 emission allowances by reducing a previously established regulatory liability related to the SO_2 emission allowances, which had no impact to earnings. See Note 17 Goodwill and Other Asset Impairments for additional information about the asset impairment charges recorded during 2010. See also Note 15 Commitments and Contingencies for additional information on emission allowances.

The following table presents the SO_2 and NO_x emission allowances held and the related aggregate SO_2 and NO_x emission allowance book values that were recorded as intangible assets at December 31, 2010. Emission allowances consist of various individual emission allowance certificates and do not expire. Emission allowances are charged to fuel expense as they are used in operations.

SO_2 and NO_x in tons	**SO_2[(a)]**	**NO_x[(b)]**	**Book Value[(c)]**
Ameren[(d)]	3,061,914	21,284	$ 7
UE	1,587,663	15,850	2
Genco	1,102,744	5,139	3

(a) Vintages are from 2010 to 2020. Each company possesses additional allowances for use in periods beyond 2020.
(b) Vintage is 2010 and the remaining unused prior years allowances.
(c) The book value represents SO_2 and NO_x emission allowances for use in periods through 2040. The book value at December 31, 2009, for Ameren, UE, and Genco was $129 million, $35 million, and $62 million, respectively.
(d) Includes amounts for Ameren registrants and nonregistrant subsidiaries.

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The following table presents amortization expense recorded in connection with the use of emission allowances, net of gains and losses from emission allowance sales, for Ameren, UE and Genco during the years ended December 31, 2010, 2009, and 2008**.** The table below does not include the intangible asset impairment charges referenced above.

	2010	2009	2008
Ameren[(a)]	**$ 21**	$ 29	$ 32
UE	**(b)**	-	-
Genco	**18**	24	26

(a) Includes allowances consumed that were recorded through purchase accounting.
(b) Less than $1 million.

Impairment of Long-lived Assets

We evaluate long-lived assets classified as held and used for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets with the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, we recognize an impairment charge equal to the carrying value of the assets in excess of estimated fair value. In the period in which we determine an asset meets the held for sale criteria, we record an impairment charge to the extent the book value exceeds its fair value less cost to sell. During 2010, Ameren and Genco recorded pretax asset impairment charges of $101 million and $64 million respectively, to reduce the carrying value of certain generating facilities to their estimated fair value. See Note 17 Goodwill and Other Asset Impairments for information about Ameren and Genco s impairments.

Investments

Ameren and UE evaluate for impairment the investments held in UE s nuclear decommissioning trust fund. Losses on assets in the trust fund could result in higher funding requirements for decommissioning costs, which UE believes would be recovered in electric rates paid by its customers. Accordingly, Ameren and UE recognize a regulatory asset on their balance sheets for losses on investments held in the nuclear decommissioning trust fund. See Note 9 Nuclear Decommissioning Trust Fund Investments for additional information.

Environmental Costs

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are expensed or deferred as a regulatory asset when it is expected that the costs will be recovered from customers in future rates. If environmental expenditures are related to facilities currently in use, such as pollution control equipment, the cost is capitalized and depreciated over the expected life of the asset.

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

Operating Revenues

UE, AIC and Genco record operating revenue for electric or natural gas service when it is delivered to customers. We accrue an estimate of electric and natural gas revenues for service rendered but unbilled at the end of each accounting period.

Trading Activities

We present the revenues and costs associated with certain energy derivative contracts designated as trading on a net basis in Operating Revenues Electric and Other.

Nuclear Fuel

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

Purchased Gas, Power and Fuel Rate-adjustment Mechanisms

Ameren s utility subsidiaries have various rate-adjustment mechanisms in place that provide for the recovery of purchased natural gas and electric fuel and purchased power costs. See Note 2 Rate and Regulatory Matters for the regulatory assets and liabilities recorded at December 31, 2010, and 2009, related to the rate-adjustment mechanisms discussed below.

In UE s and AIC s retail natural gas utility jurisdictions, changes in natural gas costs are generally reflected in billings to their natural gas utility customers through PGA clauses. The difference between actual natural gas costs and costs billed to customers in a given period are deferred as regulatory assets or liabilities. The deferred amounts are either billed or refunded to natural gas utility customers in a subsequent period.

In AIC s retail electric utility jurisdictions, changes in purchased power costs are generally reflected in billings to their electric utility customers through pass-through rate-adjustment clauses. The difference between actual purchased power costs and costs billed to customers in a given period are deferred as regulatory assets or liabilities. The deferred amounts are either billed or refunded to electric utility customers in a subsequent period.

UE has an FAC that allows an adjustment of electric rates three times per year for a pass-through to customers of 95% of changes in fuel and purchased power costs, net of off-system revenues, including MISO costs and revenues, greater or less than the amount set in base rates, subject to MoPSC prudency review. The differences between the cost of fuel incurred and the cost of fuel

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recovered from UE s customers are deferred as regulatory assets or liabilities. The deferred amounts are either billed or refunded to UE s electric utility customers in a subsequent period.

Accounting for MISO Transactions

MISO-related purchase and sale transactions are recorded by Ameren, UE and AIC using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. We record net purchases in a single hour in Operating Expenses Purchased Power and net sales in a single hour in Operating Revenues Electric in our statements of income. On occasion, prior-period transactions will be resettled outside the routine settlement process because of a change in MISO s tariff or a material interpretation thereof. In these cases, Ameren, UE and AIC recognize expenses associated with resettlements once the resettlement is probable and the resettlement amount can be estimated.

Stock-based Compensation

Stock-based compensation cost is measured at the grant date based on the fair value of the award. Ameren recognizes as compensation expense the estimated fair value of stock-based compensation on a straight-line basis over the requisite service period. See Note 12 Stock-based Compensation for additional information.

Excise Taxes

Excise taxes imposed on us are reflected on UE electric and UE and AIC natural gas customer bills. They are recorded gross in Operating Revenues and Operating Expenses Taxes Other Than Income Taxes on the statement of income. Excise taxes reflected on AIC electric customer bills are imposed on the consumer and are therefore not included in revenues and expenses. They are recorded as tax collections payable and included in Taxes Accrued on the balance sheet. The following table presents excise taxes recorded in Operating Revenues and Operating Expenses Taxes Other than Income Taxes for the years ended 2010, 2009 and 2008:

	2010	**2009**	**2008**
Ameren	**$ 189**	$ 168	$ 172
UE	**130**	112	109
AIC	**59**	56	63

Income Taxes

Ameren uses an asset and liability approach for its financial accounting and reporting of income taxes, in accordance with authoritative accounting guidance. Deferred tax assets and liabilities are recognized for transactions that are treated differently for financial reporting and income tax return purposes. These deferred tax assets and liabilities are calculated based on statutory tax rates.

We recognize that regulators will probably reduce future revenues for deferred tax liabilities initially recorded at rates in excess of the current statutory rate. Therefore, reductions in the deferred tax liability, which were recorded because of decreases in the statutory rate, were credited to a regulatory liability. A regulatory asset has been established to recognize the probable future recovery in rates of future income taxes, resulting principally from the reversal of allowance for funds used during construction, that is, equity and temporary differences related to property and plant acquired before 1976 that were unrecognized temporary differences prior to the adoption of the authoritative accounting provisions for income taxes.

Investment tax credits used on tax returns for prior years have been deferred for book purposes; the credits are being amortized over the useful lives of the related investment. Deferred income taxes were recorded on the temporary difference represented by the deferred investment tax credits and a corresponding regulatory liability. This recognizes the expected reduction in rate revenue for future lower income taxes associated with the amortization of the investment tax credits. See Note 13 Income Taxes.

UE, AIC and Genco are parties to a tax sharing agreement with Ameren that provides for the allocation of consolidated tax liabilities. The tax sharing agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. Any net benefit attributable to the parent is reallocated to other members. That allocation is treated as a contribution of capital to the party receiving the benefit.

Noncontrolling Interests

Ameren s noncontrolling interests comprise the 20% of EEI not owned by Ameren and the preferred stock not subject to mandatory redemption of the Ameren subsidiaries. These noncontrolling interests are classified as a component of equity separate from Ameren s equity in its consolidated balance sheet. Genco s noncontrolling interest comprises the 20% of EEI not owned by Genco. This noncontrolling interest is classified as a component of equity separate from Genco s equity in its consolidated balance sheet.

Earnings per Share

There were no material differences between Ameren s basic and diluted earnings per share amounts in 2010, 2009, and 2008. The number of stock options, restricted stock shares, and performance share units outstanding was immaterial. The assumed stock option conversions increased the number of shares outstanding in the diluted earnings per share calculation by 16,841 shares in 2008. There were no assumed stock option conversions in 2009 and 2010, as the remaining stock options were not dilutive. All of Ameren s remaining stock options expired in February 2010.

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Accounting Changes and Other Matters

The following is a summary of recently adopted authoritative accounting guidance as well as guidance issued but not yet adopted that could impact the Ameren Companies.

Variable-Interest Entities

In June 2009, the FASB issued amended authoritative guidance that significantly changes the consolidation rules for VIEs. The guidance requires an enterprise to qualitatively assess the determination of the primary beneficiary of a VIE and requires an ongoing reconsideration of the primary beneficiary. It also amends the events that trigger a reassessment of whether an entity is a VIE. The adoption of this guidance, effective for us as of January 1, 2010, did not have a material impact on our results of operations, financial position, or liquidity.

Disclosures about Fair Value Measurements

In January 2010, the FASB issued amended authoritative guidance regarding fair value measurements. This guidance requires disclosures regarding significant transfers into and out of Level 1 and Level 2 fair value measurements. It also requires information on purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair value measurements. Further, the FASB clarified guidance regarding the level of disaggregation, inputs, and valuation techniques. This guidance was effective for us as of January 1, 2010, with

the exception of guidance applicable to detailed Level 3 reconciliation disclosures, which was effective for us as of January 1, 2011. The adoption of this guidance did not have a material impact on our results of operations, financial position, or liquidity because it provides enhanced disclosure requirements only. See Note 8 Fair Value Measurements for additional information.

Asset Retirement Obligations

Authoritative accounting guidance 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 make adjustments to AROs based on changes in the estimated fair values of the obligations. 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 AROs affect our estimates of fair value. Ameren, UE and Genco have recorded AROs for retirement costs associated with UE s Callaway nuclear plant decommissioning costs, asbestos removal, ash ponds, and river structures. In addition, Ameren, UE and AIC have recorded AROs for the disposal of certain transformers.

Asset removal costs accrued by our rate-regulated operations that do not constitute legal obligations are classified as a regulatory liability. See Note 2 Rate and Regulatory Matters.

The following table provides a reconciliation of the beginning and ending carrying amount of AROs for the years 2010 and 2009:

	Ameren[(a)(b)]	**UE[(b)]**	**AIC[(d)]**	**Genco**
Balance at December 31, 2008	$ 411	$ 317	$ 5	$ 61
Liabilities incurred	(e)	-	(e)	-
Liabilities settled	(3)	(2)	-	(1)
Accretion in 2009[(f)]	24	18	(e)	4
Change in estimates[(g)]	2	(2)	(e)	1
Balance at December 31, 2009	$ 434[(c)]	$ 331	$ 5	$ 65[(c)]
Liabilities incurred	**$ 8**	**$ 5**	**$ (e)**	**$ 3**
Liabilities settled	**(4)**	**(4)**	**(e)**	**(e)**
Accretion in 2010[(f)]	**26**	**19**	**1**	**4**
Change in estimates[(h)]	**11**	**12**	**(3)**	**2**
Balance at December 31, 2010	**$ 475**	**$ 363**	**$ 3**	**$ 74**

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) The nuclear decommissioning trust fund assets of $337 million and $293 million as of December 31, 2010, and 2009, respectively, were restricted for decommissioning of the Callaway nuclear plant.
(c) Balance included $5 million in Other Current Liabilities on the balance sheet as of December 31, 2009.
(d) Balance included in Other Deferred Credits and Liabilities on the balance sheet.
(e) Less than $1 million.
(f) Accretion expense was recorded as an increase to regulatory assets at UE and AIC.
(g) UE and Genco changed their estimates for asbestos removal. Additionally, Genco changed the estimates related to retirement costs for its ash ponds.
(h) UE and AIC changed their estimates related to asbestos removal and contaminated transformers. Additionally, UE and Genco changed estimates related to retirement costs of their ash ponds.

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Genco Asset Sale

In June 2010, Genco completed a sale of 25% of its Columbia CT facility to the city of Columbia, Missouri. Genco received cash proceeds of $18 million from the sale. The city of Columbia also holds two options to purchase additional ownership interests in the facility under two existing power purchase agreements. Columbia can exercise one option, as amended, for an additional 25% of the facility at the end of 2011 for a purchase price of $14.9 million, at the end of 2014 for a purchase price of $9.5 million, or at the end of 2020 for a purchase price of $4 million. The other option can be exercised for another 25% of the facility at the end of 2013 for a purchase price of $15.5 million, at the end of 2017 for a purchase price of $9.5 million, or at the end of 2023 for a purchase price of $4 million. On an annual basis, the city of Columbia purchases a total of 72 megawatts of capacity and energy generated by the facility under the two existing purchase power agreements. If the city of Columbia exercises one of the purchase options described above, the power purchase agreement associated with that option would be terminated.

Employee Separation and Other Charges

In 2009, Ameren initiated a voluntary separation program that provided eligible management employees the opportunity to voluntarily terminate their employment and receive benefits consistent with Ameren s standard management severance program. This program was offered to eligible management employees at Ameren s subsidiaries, including UE, AIC and Genco. Additionally, in 2009, Ameren initiated an involuntary separation program to reduce additional management positions under terms and benefits consistent with Ameren s standard management severance program. Ameren recorded a pretax charge to earnings of $17 million in 2009 (UE $8 million, AIC $3 million, Genco $5 million) for the severance costs related to both the voluntary and involuntary separation programs as well as for Merchant Generation staff reductions announced in 2009. These charges were recorded in other operations and maintenance expense in the applicable statements of income. Substantially this entire amount was paid prior to December 31, 2009. The number of positions eliminated as a result of these separation programs, including the Merchant Generation staff reductions, was approximately 300. In addition to these programs, Genco recorded a $4 million pretax charge to earnings in 2009 in connection with the retirement of two generating units at its Meredosia power plant and for related obsolete inventory.

In 2010, Ameren s Merchant Generation segment initiated additional involuntary separation programs to reduce additional positions under the terms and benefits consistent with Ameren s standard separation program. Ameren and Genco recorded a pretax charge to earnings of $4 million in 2010 for the severance costs related to 2010 involuntary separation programs. These charges were recorded in other operations and maintenance expense on Ameren s and Genco s statement of income and

approximately $2 million was accrued in other current liabilities on Ameren s and Genco s balance sheet at December 31, 2010.

Coal Contract Settlement

In June 2008, Genco entered into a settlement agreement with a coal mine owner. The owner provided Genco with a lump-sum payment of $60 million in July 2008 because of the coal supplier s premature closing of a mine and the early termination of a coal supply contract. The settlement agreement compensated Genco, in total, for higher fuel costs it incurred in 2008 ($33 million) and in 2009 ($27 million) as a result of the mine closure and contract termination.

NOTE 2 RATE AND REGULATORY MATTERS

Below is a summary of significant regulatory proceedings and related lawsuits. We are unable to predict the ultimate outcome of these matters, the timing of the final decisions of the various agencies and courts, or the impact on our results of operations, financial position, or liquidity.

Missouri

2009 Electric Rate Order

In January 2009, the MoPSC issued an order approving an increase for UE in annual revenues of approximately $162 million for electric service and the implementation of a FAC and a vegetation management and infrastructure inspection cost tracking mechanism, among other things. The rate changes necessary to implement the provisions of the MoPSC order were effective March 1, 2009. In February 2009, Noranda, UE s largest electric customer, and the Missouri Office of Public Counsel appealed certain aspects of the MoPSC decision to the Circuit Court of Pemiscot County, Missouri, the Circuit Court of Stoddard County, Missouri, and the Circuit Court of Cole County, Missouri. The Stoddard and Pemiscot County cases were consolidated (collectively, the Stoddard Circuit Court), and the Cole County case was dismissed. In September 2009, the Stoddard Circuit Court granted Noranda s request to stay the electric rate increase granted by the January 2009 MoPSC order as it applies specifically to Noranda s electric service account until the court renders its decision on the appeal. From the granting of the stay request until June 2010, Noranda paid into the Stoddard Circuit Court s registry the entire amount of its monthly base rate increase and monthly FAC payments. Since June 2010, when the May 2010 electric rate order became effective, Noranda ceased making base rate payments into the Stoddard Circuit Court s registry. Noranda has continued to pay into the Stoddard Circuit Court s registry its monthly FAC payments relating to electric service during the time periods prior to the effectiveness of the May 2010 electric rate order. Because of the lag between accumulation of changes in net fuel costs and when those net fuel costs are recovered through FAC charges applied to customers bills, a portion of Noranda s FAC payment in January 2012 is expected to be the last contested amount deposited into the Stoddard Circuit Court s registry relating to this 2009 electric rate order appeal. As of December 31, 2010, the aggregate amount held by the Stoddard Circuit Court was approximately $10 million.

In August 2010, the Stoddard Circuit Court issued a judgment that reversed parts of the MoPSC s decision. Also, upon issuance, the Stoddard Circuit Court suspended its own judgment. Therefore, the entire amount currently held in the Stoddard Circuit Court s registry will remain in the Stoddard Circuit Court s registry pending the appeal discussed below.

In September 2010, UE filed an appeal with the Missouri Court of Appeals for the Southern District of Missouri. The Court of Appeals will conduct an independent review of the MoPSC s order. UE believes the Stoddard Circuit Court s judgment, which reversed parts of the MoPSC decision, will be found erroneous by the Court of Appeals; however, there can be no assurances that UE s appeal will be successful. If UE prevails on all issues of its appeal, UE will receive all of the funds held in the Stoddard Circuit Court s registry, plus accrued interest. If UE were to conclude that some portion of the funds held in the Stoddard Circuit Court s registry becomes probable of refund to Noranda, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision is made. A decision by the Court of Appeals is not expected until at least the third quarter of 2011.

See the 2010 Electric Rate Order section below for information about four industrial customers, one of which is Noranda, who have filed an appeal with the Cole County Circuit Court and also were granted a stay for their rate increases granted by the MoPSC s 2009 electric rate order as they specifically apply to each of their electric service accounts.

2010 Electric Rate Order

In May 2010, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $230 million, including $119 million to cover higher fuel costs and lower revenue from sales outside UE s system. The revenue increase was based on a 10.1% return on equity, a capital structure composed of 51.3% common equity, and a rate base of approximately $6 billion. The rate changes became effective on June 21, 2010. The MoPSC order also included the following provisions, among other things:

- Approval of the continued use of UE s existing FAC at the current 95% sharing level.
- Approval of the continued use of UE s existing vegetation management and infrastructure cost tracker.
- Approval of an increase in UE s annual depreciation rate due largely to the adoption of the life span depreciation methodology for its non-nuclear power plants.
- Denial of UE s request to implement a storm restoration cost tracker.

In addition, the order implemented several stipulations previously agreed to by UE, the MoPSC staff, and other parties to the proceedings. One stipulation included UE s agreement to withdraw its request for an environmental cost recovery mechanism in exchange for the ability to continue recording for ratemaking purposes an allowance for funds used during construction and to defer depreciation costs for pollution control equipment at the Sioux plant until the earlier of January 2012 or when the cost of that equipment is placed in customer rates. This treatment allows UE to defer these costs as a regulatory asset, which will be amortized upon their inclusion in rates. UE will have the ability to request the implementation of an environmental cost recovery mechanism in a future rate case proceeding. Another approved stipulation allows UE to recover its portion of Ameren s September 2009 common stock issuance costs. The order also implemented the parties agreement to prospectively include the margins on certain wholesale contracts in UE s FAC in exchange for an increase in the jurisdictional cost allocation to retail customers. In addition, the order implements the parties agreement to a mechanism that will prospectively address the significant lost revenues UE can incur due to future operational issues at Noranda s smelter plant. This mechanism will permit UE, when a loss of service occurs at the Noranda plant, to sell the power not taken by Noranda and use the proceeds of those sales to offset the revenues lost from Noranda. UE would be allowed to keep the amount of revenues necessary to compensate UE for significant Noranda usage reductions but any excess revenues above the level necessary to compensate UE would be refunded to retail customers through the FAC. Approved stipulations also include the continued use of the regulatory tracking mechanism for pension and postretirement benefit costs and the discontinuation of the SO_2 emission allowance sales tracker, among other things.

In June 2010, UE and other parties to the rate case filed for rehearing of certain aspects of the MoPSC order. The MoPSC denied all rate order rehearing requests filed by UE and other parties. UE appealed the return on equity included in the MoPSC order to the Circuit Court of Cole County, Missouri (Circuit Court). UE subsequently withdrew its appeal as the outcome of the pending electric rate case would supersede the result of this appeal. A group of industrial customers also appealed certain aspects of the MoPSC order to the Circuit Court. A decision is expected to be issued on the industrial customers appeal by the Circuit Court in 2011.

On February 16, 2011, the Missouri Office of Public Counsel (MoOPC) made a filing with the MoPSC in which the MoOPC argued that the December 20, 2010 Order Granting Stay Pursuant to Section 386.520 (Stay Order), discussed below, of the Circuit Court should apply to all UE customers rather than to just the four UE industrial customers that requested the Circuit Court to grant these industrial customers request to stay the MoPSC s 2010 Missouri electric rate order as to their billings. On that basis, the MoOPC requested the MoPSC to suspend UE s currently effective rate schedules (approved by the 2010 Missouri electric rate order) and to replace them with UE s previously effective rate schedules (approved by the 2009 Missouri electric rate order) for all customers. If the requested suspension occurs, it would continue until the earlier of the time that a subsequent order is issued by the MoPSC, or an order reversing any such suspension is issued by a court of competent jurisdiction, but in no event beyond the implementation of new electric rates for UE. It is anticipated that new electric rates for UE will take effect by early August 2011, pursuant to an anticipated MoPSC rate order in UE s currently pending electric rate proceeding. If the currently effective 2010 rate schedules are suspended for all customers such that UE is only able to charge customers under its previously effective rate schedules for service provided for the period March through August 2011, the reduced charges, which would reflect the difference between billings under the 2010 Missouri electric rate order and billings under the 2009 Missouri electric rate order, are estimated at approximately $100 million and would result in corresponding reductions in pretax earnings and cash flows.

Also on February 16, 2011, the Missouri Industrial Energy Consumers (MIEC), of which the four UE industrial customers referred to above are members, made a filing with the MoPSC in response to the MoOPC filing discussed above. In its filing, MIEC supported the position set forth in the MoOPC filing that the Stay Order should apply to all UE customers, except that MIEC requested the MoPSC to suspend UE s currently effective rate schedules, including its FAC, and replace them with UE s rate schedules approved by the MoPSC in its 2007 electric rate order. If the requested suspension occurs, it would continue until the earlier of the time that a subsequent order is issued by the MoPSC, or an order reversing any such suspension is issued by a court of competent jurisdiction, but in no event beyond the implementation of new electric rates for UE. As noted, it is anticipated that new electric rates for UE will take effect by early August 2011. If the currently effective 2010 rate schedules (including the FAC) are suspended for all customers such that UE is only able to charge customers under its previously effective rate schedules for service provided for the period March through August 2011, the reduced charges, which would reflect the difference between billings under the 2010 Missouri electric rate order and billings under the 2007 Missouri electric rate order, including FAC billings, are estimated at approximately $300 million and would result in corresponding reductions in pretax earnings and cash flows.

The filings by the MoOPC and MIEC relate to the December 20, 2010 Stay Order, in which the Circuit Court granted the request of four UE industrial customers to stay the MoPSC s 2010 Missouri electric rate order and to require those customers to pay into the Circuit Court s registry the difference between their billings under the 2010 Missouri electric rate order and their billings under a Missouri electric rate order that became effective in June 2007, the last UE rate order for which appeals have been

exhausted. On February 15, 2011, the four UE industrial customers posted the bond required by the Stay Order and are expected to begin making the required payments into the Circuit Court s registry.

The Stay Order does not address the merits of the appeals of the MoPSC s 2010 electric rate order or the 2009 electric rate order, which will be addressed in the ordinary course of the judicial review process. The judicial review process typically takes 18 to 24 months to complete following the initiation of the process. At this time, UE does not believe any aspect of the 2009 and 2010 electric rate increases authorized by the 2009 and 2010 Missouri electric rate orders are probable of refund to UE s customers. If UE were to conclude that some portion of these rate increases become probable of refund to UE s customers, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision was made.

UE disagrees with the Stay Order, as well as the related filings made by the MoOPC and MIEC with the MoPSC. With respect to further proceedings regarding the Stay Order, the pending review proceedings regarding the 2009 and 2010 Missouri electric rate orders and the MoOPC s and MIEC s filings with the MoPSC, UE will continue to address the merits of those orders and filings through the judicial and regulatory review processes.

There could be other material negative effects on UE and Ameren beyond those discussed above, which cannot be determined at this time. We cannot predict the ultimate outcome of these proceedings, which could have a material effect on UE s and Ameren s results of operations, cash flows and financial position.

Pending Electric Rate Case

On September 3, 2010, UE filed a request with the MoPSC to increase its annual revenues for electric service by approximately $263 million. This increase request was based primarily on energy infrastructure investments, costs incurred to implement environmental controls and other costs incurred to continue systemwide reliability improvements for customers. Of that request, approximately $110 million relates to recovery of the cost of installing and operating two scrubbers at UE s Sioux plant. Also included in this requested increase is a $73 million anticipated increase in normalized net fuel costs above the net fuel costs included in base rates previously authorized by the MoPSC in its May 2010 electric rate order. Absent initiation of this general rate proceeding, 95% of this amount would have been reflected in rate adjustments implemented under UE s FAC. Capital additions relating to enhancements at the rebuilt Taum Sauk facility were also included in the increase request. The electric rate increase request is based on a 10.9% return on equity, a capital structure composed of 50.9% common equity, an aggregate electric rate base of $6.8 billion, and a test year ended March 31, 2010, with certain pro-forma adjustments through the anticipated true-up date of

February 28, 2011.

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As a part of its filing, UE also requested that the MoPSC approve the implementation of an infrastructure investment tracking mechanism as well as enhanced energy efficiency cost recovery. The infrastructure investment tracking mechanism would allow UE to continue recording an allowance for funds used during construction and to defer depreciation expenses for certain projects beyond their in-service dates and prior to those projects being reflected in rates, with the amounts deferred being recoverable through future rate case proceedings. The enhanced energy efficiency cost recovery provision would permit UE to recover its investments in energy efficiency programs over three years instead of six years and to offset the under-recovery of fixed costs resulting from implementation of energy efficiency measures. UE also requested continued use of its existing FAC, vegetation management and infrastructure cost tracker, and the regulatory tracking mechanism for pension and postretirement benefit costs authorized by the MoPSC in earlier electric rate orders.

In February 2011, the MoPSC staff responded to the UE request for an electric service rate increase. The MoPSC staff recommended an increase to UE s annual revenues of between $45 million and $99 million based on a return on equity of 8.25% to 9.25%. Included in this recommendation was approximately $50 million of increases in normalized net fuel costs and $32 million of asset disallowances relating to the Sioux plant scrubbers. Other parties also made recommendations through testimony filed in this case.

A decision by the MoPSC in this proceeding is required by the end of July 2011. UE cannot predict the level of any electric service rate change the MoPSC may approve, when any rate change may go into effect, or whether any rate increase that may eventually be approved will be sufficient for UE to recover its costs and earn a reasonable return on its investments when the increase goes into effect.

2011 Natural Gas Delivery Service Rate Order

In January 2011, the MoPSC approved a stipulation and agreement that resolved a June 2010 request by UE to increase annual natural gas revenues. The stipulation and agreement provided for an increase in annual natural gas delivery revenues of $9 million, which included approximately $2 million of annual revenues previously collected through the ISRS rider for the test year ended December 31, 2009. The new rates became effective on February 20, 2011. The stipulation and agreement approved a revised block-rate structure for residential customers that results in more certainty of margin revenue recovery regardless of weather conditions or conservation efforts, as recovery is less dependent on usage. The new residential structure is expected to allow UE to recover approximately half of its natural gas non-PGA residential revenues through a fixed monthly charge, with the remaining amount to be recovered based on sales.

As part of the stipulation and agreement, UE will not file a separate natural gas rate increase request before December 31, 2012. However, UE can file a combined natural gas and electric rate case before that date. Further, this agreement does not prevent UE from filing to recover infrastructure replacement costs through an ISRS during this moratorium. The return on equity to be used by UE for purposes of an ISRS tariff filing is 10%.

FAC Prudence Review

Missouri law requires the MoPSC to complete prudence reviews of UE s FAC at least every 18 months. In August 2010, the MoPSC staff completed a prudence review of the FAC from March 1, 2009, to September 30, 2009. The MoPSC staff contends that UE should have included in the FAC calculation all costs and revenues associated with certain contract sales that were made due to the loss of Noranda load caused by a severe ice storm in January 2009. UE disagrees with the MoPSC staff s classification of these transactions and opposes their inclusion in the FAC calculation. UE recognized margin associated with these contracts of $17 million during the period reviewed by the MoPSC and an additional $25 million of margin subsequent to September 30, 2009. If the MoPSC were to agree with the staff position, and if the MoPSC s order were to be upheld by the courts on appeal, UE would be required to pass through to customers the $42 million in margin associated with these contracts and record a charge to earnings. The MoPSC is expected to issue an order with respect to this prudence review in 2011. If UE were to conclude that some portion of these contested FAC amounts become probable of refund to UE s customers, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision is made. UE cannot predict the outcome of this MoPSC prudence review.

Renewable Energy Portfolio Requirement

A ballot initiative passed by Missouri voters in November 2008 created a renewable energy portfolio requirement. UE and other Missouri investor-owned utilities will be required to purchase or generate from renewable energy sources electricity equaling at least 2% of native load sales by 2011, with that percentage increasing in subsequent years to at least 15% by 2021, subject to a 1% limit on customer rate impacts. At least 2% of each portfolio requirement must be derived from solar energy. Compliance with the renewable energy portfolio requirement can be achieved through generation, the procurement of renewable energy, or the procurement of renewable energy credits. UE expects that any related costs or investments would ultimately be recovered in rates.

In July 2010, the MoPSC issued final rules implementing the state s renewable energy portfolio requirement. In addition to other concerns, UE objected to the MoPSC rules creating geographical restrictions as well as the calculation of the 1% limit on customer rates. In February 2011, the Missouri legislature rejected the contested portion of the MoPSC rules creating geographical restrictions. This legislative action allows UE to comply with the law through its own generation or the procurement of renewable energy or renewable energy credits from sources regardless of geographical location. In August 2010, UE filed an appeal with the Circuit Court of Cole County, Missouri. UE is appealing the portion of the MoPSC rules calculating the 1% limit on customer rates. UE cannot predict when the court will issue a ruling or the ultimate outcome of the appeal.

Illinois

2010 Electric and Natural Gas Delivery Service Rate Order

In April 2010, the ICC issued a rate order for AIC, which was amended in May 2010, that approved a net increase in annual revenues for electric delivery service of $35 million and a net decrease in annual revenues for natural gas delivery service of $20 million. The rate changes became effective in May 2010. In response to the ICC rate order, AIC took steps to reduce expenditures to align its spending with the revenues allowed in the amended rate order.

The ICC order confirmed the previously approved 80% allocation of fixed nonvolumetric residential and commercial natural gas customer charges, and approved a higher percentage of recovery of fixed nonvolumetric electric residential and commercial customer charges. The percentage of costs to be recovered through fixed nonvolumetric electric residential and commercial customer and meter charges increased from 27% to 40%.

The ICC order also extended the amortization period of the integration-related regulatory asset for Ameren s acquisition of IP, which was previously set to be fully amortized by December 2010. The new order extended the amortization for two years beginning in May 2010. The ICC order also created a $3 million regulatory asset for AIC s costs incurred in 2009 for its voluntary and involuntary separation programs. These costs are being amortized over three years, beginning May 2010.

AIC and certain intervenors were granted a rehearing with the ICC. In November 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the net $15 million increase authorized in the ICC s May 2010 amended rate order. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues became effective on November 19, 2010.

In December 2010, AIC and an intervenor appealed portions of the ICC s orders to the Appellate Court of the Fourth District of Illinois. A decision by the Appellate Court is expected in 2011.

Pending Electric and Natural Gas Delivery Service Rate Cases

AIC filed a request with the ICC in February 2011 to increase its annual revenues for electric delivery service by

$60 million. The electric rate increase request is based on an 11.25% return on equity, a capital structure composed of 53% equity, and a rate base of $2 billion.

AIC also filed a request with the ICC in February 2011 to increase its annual revenues for natural gas delivery service by $51 million. The natural gas rate increase request is based on an 11.0% return on equity, a capital structure composed of 53% equity, and a rate base of $978 million.

In an attempt to limit regulatory lag, AIC is also using a future test year, 2012, in each of these rate requests. Additionally, AIC is requesting a rider mechanism for its pension costs. This requested rider mechanism would allow AIC to recover or refund any difference between pension expense incurred and the amount allowed in rates annually, subject to an annual reconciliation.

A decision by the ICC in these proceedings is required by January 2012. AIC cannot predict the level of any delivery service rate changes the ICC may approve, when any rate changes may go into effect, or whether any rate changes that may eventually be approved will be sufficient to enable AIC to recover its costs and earn a reasonable return on its investments when the rate changes go into effect.

2007 Illinois Electric Settlement Agreement

In 2007, key stakeholders in Illinois agreed to avoid rate rollback and freeze legislation that would impose a tax on electric generation. These stakeholders wanted to address the increase in electric rates and the future power procurement process in Illinois. The terms of the agreement included a comprehensive rate relief and customer assistance program. The 2007 Illinois Electric Settlement Agreement provided approximately $1 billion of funding from 2007 to 2010 for rate relief for certain electric customers in Illinois, including approximately $488 million for customers of AIC. Pursuant to the 2007 Illinois Electric Settlement Agreement, AIC, Genco and AERG made aggregate contributions of $150 million over the four-year period, with $60 million coming from AIC, $62 million from Genco, and $28 million from AERG. As of December 31, 2010, AIC, Genco and AERG had no obligations remaining under the 2007 Illinois Electric Settlement Agreement.

Ameren, AIC and Genco recognized in their financial statements the costs of their respective rate relief contributions and program funding under the 2007 Illinois Electric Settlement Agreement in a manner corresponding with the timing of the funding. As a result, Ameren, AIC and Genco, incurred charges to earnings, primarily recorded as a reduction to electric operating revenues, during the year ended December 31, 2010, of $3 million, $1 million, and $1 million, respectively (year ended December 31, 2009 $25 million, $10 million, and $10 million, respectively) under the terms of the 2007 Illinois Electric Settlement Agreement. Other electric generators and utilities in Illinois contributed $851 million to the comprehensive rate relief and customer assistance program.

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ICC Reliability Audit

In August 2007, the ICC retained Liberty Consulting Group to investigate, analyze, and report to the ICC on AIC s transmission and distribution systems and reliability following the July 2006 wind storms and a November 2006 ice storm. In October 2008, Liberty Consulting Group presented the ICC with a final report containing recommendations for AIC to improve its systems and response to emergencies. In November 2008, AIC presented to the ICC a plan to implement Liberty Consulting Group s recommendations.

AIC has committed to and is implementing various recommendations contained in Liberty Consulting Group s report, as outlined in its November 2008 plan. However, in order to fulfill that commitment in a timely manner, AIC must be able to align the timing of its distribution-implementation expenditures with the recognition of those costs in rates. Without the necessary funding or a rider mechanism to recover the distribution costs, AIC may defer some of the projects until the distribution costs can be recovered either in base rates or through some other cost recovery mechanism. The recovery of costs not already approved as part of the 2010 rate order will be sought in future rate proceedings, including the 2011 pending rate case described above.

Federal

Electric Transmission Investment

In 2006, Ameren formed a wholly owned subsidiary, Ameren Illinois Transmission Company, to construct and operate electric transmission assets in Illinois. In 2010, that subsidiary was renamed as ATXI. In December 2010, ATXI received MISO approval to become a transmission owner. In January 2011, ATXI received FERC approval for rate recovery of the transmission line it constructed and placed in service in 2010. Based on preliminary transmission rate calculations, ATXI anticipates revenues of approximately $7 million in 2011.

In August 2010, Ameren announced the formation of ATX. In August 2010, Ameren, on behalf of UE, AIC, ATXI and ATX, filed a request with FERC seeking transmission rate incentives for four new transmission projects. These initial projects, subject to regulatory approval, consist of a potential $1.3 billion investment in high voltage transmission projects in Illinois and Missouri. There is no statutory date by which FERC must issue an order in this matter; however, Ameren expects FERC will issue an order in 2011.

Regional Transmission Organization

UE is a transmission owning member of MISO, which is a FERC-regulated RTO that provides transmission tariff administration services for electric transmission systems. UE received authorization from the MoPSC to participate in MISO, subject to certain conditions.

As required by the MoPSC, UE filed a study in November 2007 with the MoPSC evaluating the costs and benefits of UE s participation in MISO. UE s continued, conditional MISO participation is authorized by the MoPSC through April 30, 2012. The MoPSC order gives UE the right to seek permission from the MoPSC for early withdrawal from MISO if UE determines that sufficient progress toward mitigating some of the continuing uncertainties respecting its MISO participation is not being made. As required by the MoPSC, in November 2010, UE filed another study with the MoPSC updating its evaluation of the costs and benefits of UE s participation in MISO. UE s filing noted a number of uncertainties associated with the cost-benefit study, including issues associated with the UE-MISO service agreement and MISO revenue allocation. UE s study concluded that it should remain in MISO through April 30, 2012; however, additional studies should be conducted to determine if UE s participation in MISO should be extended past that date. If UE were to withdraw from MISO, UE might need to obtain FERC approval and to meet conditions imposed by FERC, in addition to obtaining MoPSC approval.

FERC Order MISO Charges

Complaints were filed with FERC by UE and AIC as well as other MISO participants with respect to the FERC s March 2007 order involving the reallocation of certain MISO operational costs among MISO participants retroactive to 2005. Subsequently, FERC has issued a series of orders related to the applicability and the implementation of the order, which in some cases have conflicted with previous orders.

In May 2009, FERC changed the effective date for refunds such that certain operational costs will be allocated among MISO market participants beginning November 2008, instead of August 2007. In June 2009, UE, CIPS, CILCO and IP filed a request for hearing. The rehearing request is pending.

In June 2009, FERC issued an order dismissing rehearing requests of a November 2008 order and waiving refunds of amounts billed that were included in the MISO charge, under the assumption that there was a rate mismatch for the period April 2006, through November 2007. UE, CIPS, CILCO and IP filed a request for rehearing in July 2009. This rehearing request is pending.

UE and AIC do not believe that the ultimate resolution of these proceedings will have a material effect on their results of operations, financial position, or liquidity.

MISO and PJM Dispute Resolution

During 2009 and 2010, MISO and PJM discovered errors in the calculations quantifying certain transactions between the RTOs, which both parties alleged had financial impacts on their respective markets. As a result, during 2010 each RTO filed separate complaints with FERC against the other. In January 2011, a settlement agreement was filed with FERC by the two RTOs. Under the agreement, no payment between the RTOs will be required, but financial settlement practices will be modified to ensure greater accuracy for transactions between the RTOs. The January 2011 settlement agreement filed with FERC and the modification of settlement practices will not have a material impact on the Ameren Companies results of operations, financial position, or liquidity. Ameren is not able to predict if or when FERC will approve the settlement agreement.

UE Power Purchase Agreement with Entergy Arkansas, Inc.

In July 2007, FERC issued a series of orders addressing a complaint filed by the Louisiana Public Service Commission (LPSC) against Entergy Arkansas, Inc. (Entergy) and certain of its affiliates. The complaint alleged unjust and unreasonable cost allocations. As a result of the FERC orders, Entergy began billing UE for additional charges under a 165-megawatt power purchase agreement, and UE paid these charges. Additional charges continued during the remainder of the term of the power purchase agreement, which expired on August 31, 2009. Although UE was not a party to the FERC proceedings that gave rise to these additional charges, UE intervened in related FERC proceedings. UE also filed a complaint with FERC against Entergy and Entergy Services, Inc. in April 2008 to challenge the additional charges. In September 2008, the presiding FERC administrative law judge issued an initial decision finding that Entergy s allocation of such additional charges to UE was just and reasonable. In January 2010, FERC issued an opinion reversing the administrative law judge s initial decision and ruling that Entergy may not pass additional charges on to UE. In February 2010, Entergy filed a request for rehearing of the January 2010 opinion. UE has not recorded any prospective refund for additional charges paid as a result of the July 2007 order.

The LPSC appealed FERC s orders regarding LPSC s complaint against Entergy Services, Inc. to the U.S. Court of Appeals for the District of Columbia. In April 2008, that court ordered further FERC proceedings regarding the LPSC complaint. The court ordered FERC to explain its previous denial of retroactive refunds and the implementation of prospective charges. FERC s decision on remand of the retroactive impact of these issues could have a financial impact on UE. UE is unable to predict how FERC will respond to the court s decisions. UE estimates that it could incur an additional expense of up to $25 million if FERC orders retroactive application for the years 2001 to 2005. UE believes that the likelihood of incurring any expense is not probable, and therefore no liability has been recorded as of December 31, 2010. UE plans to participate in any proceeding that FERC initiates to address the court s decisions.

COLA and ESP

In 2008, UE filed an application with the NRC for a COLA for a new 1,600-megawatt nuclear unit at UE s existing Callaway County, Missouri, nuclear plant site. In

2009, UE suspended its efforts to build a new nuclear unit at its existing Missouri nuclear plant site, and the NRC suspended review of the COLA.

UE is considering filing an application to obtain an ESP from the NRC at the Callaway nuclear plant site. An ESP approves a specific location for a nuclear facility; however, additional licenses would be required for the specific type and design of nuclear facility to be built at that site. An ESP does not authorize construction of a plant. An ESP is valid for 20 years and potentially could be renewed for up to an additional 20 years. In December 2010 and January 2011, the Missouri Energy Partnership Act was separately introduced in both the Missouri Senate and House of Representatives. The purpose of this legislation is to maintain an option for nuclear power in the state of Missouri, recover the costs of the ESP for a period up to 20 years, and provide appropriate consumer protections.

All of Missouri s major electric utility providers, including cooperatives, municipals, and other investor-owned utilities, are supporting the passage of this legislations. In addition, the governor of Missouri, labor and other key stakeholders are supporting this legislation.

Should the Missouri legislation be enacted into law, UE plans to file an ESP application with the NRC in 2011. NRC approval of an ESP application often takes three to four years.

As of December 31, 2010, UE had capitalized approximately $67 million relating to its efforts to construct a new nuclear unit. All of these incurred costs will remain capitalized while management assesses all options to maximize the value of its investment in this project. If all efforts are permanently abandoned or management concludes it is probable the cost incurred will be disallowed in rates, a charge to earnings could be recognized in a future period.

Pumped-storage Hydroelectric Facility Relicensing

In June 2008, UE filed a relicensing application with FERC to operate its Taum Sauk pumped-storage hydroelectric facility for another 40 years. The existing FERC license expired on June 30, 2010. On July 2, 2010, UE received a license extension that allows Taum Sauk to continue operations until FERC issues a new license. UE conducted studies using current field data and submitted the study results to multiple state and federal agencies in February 2011. UE anticipates filing the study results with FERC in the spring of 2011. A FERC order is expected after a review of the study results is completed. However, we cannot predict the ultimate outcome of the order.

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Regulatory Assets and Liabilities

In accordance with authoritative accounting guidance regarding accounting for the effects of certain types of regulation, UE and AIC defer certain costs pursuant to actions of regulators or based on the expected ability to recover such costs in rates charged to customers. UE and AIC also defer certain amounts pursuant to actions of regulators or based on the expectation that such amounts will be returned to customers in future rates. The following table presents Ameren s, UE s and AIC s regulatory assets and regulatory liabilities at December 31, 2010 and 2009:

		2010			**2009**	
	Ameren(a)	**UE**	**AIC**	**Ameren(a)**	**UE**	**AIC**
Current regulatory assets:						
Under-recovered FAC(b)(c)	**$ 158**	**$ 158**	**$ -**	$ 39	$ 39	$ -
Under-recovered Illinois electric power costs(b)(d)	**4**	**-**	**4**	5	-	5
Under-recovered PGA(b)(d)	**2**	**-**	**2**	4	-	4
MTM derivative assets(e)	**103**	**21**	**254**	62	24	165
Total current regulatory assets	**$ 267**	**$ 179**	**$ 260**	$ 110	$ 63	$ 174
Noncurrent regulatory assets:						
Pension and postretirement benefit costs(f)	**$ 555**	**$ 251**	**$ 304**	$ 659	$ 288	$ 371
Income taxes(g)	**230**	**225**	**5**	192	190	2
Asset retirement obligation(h)	**9**	**3**	**6**	36	31	5
Callaway costs(b)(i)	**51**	**51**	**-**	55	55	-
Unamortized loss on reacquired debt(b)(j)	**53**	**25**	**28**	56	26	30
Recoverable costs contaminated facilities(k)	**127**	**-**	**127**	150	-	150
IP integration(l)	**7**	**-**	**7**	17	-	17
Recoverable costs debt fair value adjustment(m)	**5**	**-**	**5**	6	-	6
MTM derivative assets(e)	**85**	**14**	**249**	49	10	324
SO_2 emission allowances sale tracker(n)	**12**	**12**	**-**	16	16	-
FERC-ordered MISO resettlements March 2007(o)	**3**	**3**	**-**	7	7	-
Vegetation management and infrastructure inspection(p)	**3**	**3**	**-**	7	7	-
Storm costs(q)	**23**	**23**	**-**	27	27	-
Demand-side costs(r)	**39**	**39**	**-**	15	15	-
Reserve for workers compensation liabilities(s)	**14**	**8**	**6**	15	9	6
Bad debt rider (t)	**2**	**-**	**2**	30	-	30
Credit facilities fees(u)	**12**	**12**	**-**	-	-	-
Employee separation costs(v)	**8**	**6**	**2**	-	-	-
Common stock issuance costs(w)	**12**	**12**	**-**	-	-	-
Construction accounting for pollution control equipment(b)(x)	**4**	**4**	**-**	-	-	-
Other(y)	**5**	**3**	**2**	5	2	3
Total noncurrent regulatory assets	**$ 1,259**	**$ 694**	**$ 743**	$ 1,342	$ 683	$ 944
Current regulatory liabilities:						
Over-recovered FAC(z)	**$ -**	**$ -**	**$ -**	$ 10	$ 10	$ -
Over-recovered Illinois electric power costs(d)	**62**	**-**	**62**	44	-	44
Over-recovered PGA(d)	**12**	**1**	**11**	13	4	9
MTM derivative liabilities(aa)	**25**	**22**	**3**	15	11	4
Total current regulatory liabilities(bb)	**$ 99**	**$ 23**	**$ 76**	$ 82	$ 25	$ 57
Noncurrent regulatory liabilities:						
Income taxes(cc)	**$ 54**	**$ 48**	**$ 6**	$ 72	$ 59	$ 13
Removal costs(dd)	**1,177**	**655**	**522**	1,084	716	367
Emission allowances(ee)	**2**	**2**	**-**	35	35	-
Vegetation management and infrastructure inspection(ff)	**3**	**3**	**-**	2	2	-
MTM derivative liabilities(aa)	**20**	**13**	**7**	14	12	2
Bad debt rider(gg)	**5**	**-**	**5**	2	-	2
Pension and postretirement benefit costs tracker(hh)	**45**	**45**	**-**	41	41	-
Energy efficiency rider(ii)	**13**	**-**	**13**	7	-	7
Total noncurrent regulatory liabilities	**$ 1,319**	**$ 766**	**$ 553**	$ 1,257	$ 865	$ 391

(a) Includes intercompany eliminations.
(b) These assets earn a return.
(c) Under-recovered fuel costs for periods from June 2009 through December 2010. Specific accumulation periods aggregate the under-recovered costs over four months, any related adjustments occur over the following four months, and then recovery from customers occurs over the next 12 months.
(d) Costs under-or over-recovered from utility customers. Amounts will be recovered from, or refunded to, customers within one year of the deferral.

(e) Deferral of commodity-related derivative MTM losses, as well as the MTM losses on financial contracts entered into by AIC with Marketing Company.
(f) These costs are being amortized in proportion to the recognition of prior service costs (credits), transition obligations (assets), and actuarial losses (gains) attributable to Ameren s pension plan and postretirement benefit plans. See Note 11 Retirement Benefits for additional information.
(g) Offset to certain deferred tax liabilities for expected recovery of future income taxes when paid. See Note 13 Income Taxes for amortization period.
(h) Recoverable costs for AROs at our rate-regulated operations, including net realized and unrealized gains and losses related to the nuclear decommissioning trust fund investments. See Note 1 Summary of Significant Accounting Policies Asset Retirement Obligations.
(i) 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.
(j) Losses related to reacquired debt. These amounts are being amortized over the lives of the related new debt issuances or the remaining lives of the old debt issuances if no new debt was issued.
(k) The recoverable portion of accrued environmental site liabilities, primarily collected from electric and natural gas customers through ICC-approved cost recovery riders. The period of recovery will depend on the timing of actual expenditures. See Note 15 Commitments and Contingencies for additional information.
(l) Reorganization costs related to the integration and restructuring of IP into the Ameren system. These costs are recoverable in rates through May 2012.
(m) A portion of unamortized debt fair value adjustment recorded upon Ameren s acquisition of IP. This portion is being amortized over the remaining life of the related debt, beginning with the expiration of the electric rate freeze in Illinois on January 1, 2007.
(n) A regulatory tracking mechanism for gains on sales of SO_2 emission allowances, net of SO_2 premiums incurred under the terms of coal procurement contracts, plus any SO_2 discounts received under such contracts, as approved in a MoPSC order. The MoPSC s May 2010 electric rate order discontinued any future deferrals under this tracking mechanism. The MoPSC s order continued to allow recovery of the previously incurred cost through either February 2011 or June 2012, depending on when the cost was incurred.
(o) Costs associated with a March 2007 FERC order that resettled costs among MISO market participants. The costs were previously charged to expense but were subsequently reversed and recorded as a regulatory asset. These costs are recoverable in rates through June 2012.
(p) A regulatory tracking mechanism for the difference between the level of vegetation management and infrastructure inspection costs incurred by UE and the level of such costs built into electric rates. UE s vegetation management and infrastructure inspection costs from January 2008 through September 2008 exceeded the amount allowed in base rates. The excess cost incurred during that time period is being amortized over three years, beginning in March 2009. UE s vegetation management and infrastructure inspection costs from March 2010 through June 2010 also exceeded the amount allowed in base rates. The amortization period for these excess costs incurred from March 2010 through June 2010 will be determined in UE s pending electric rate case.
(q) Actual storm costs in a test year that exceed the MoPSC staff s normalized storm costs for rate purposes. The 2006 storm costs are being amortized over five years, beginning on June 4, 2007. The 2008 storm costs are being amortized over five years, beginning on March 1, 2009. In addition, the balance includes January 2007 ice storm costs that UE will recover as a result of a MoPSC accounting order issued in April 2008. These costs are being amortized over five years, beginning in March 2009, as approved by the January 2009 MoPSC electric rate order. The 2009 storm costs are being amortized over five years, beginning in July 2010, as approved by the May 2010 MoPSC electric rate order.
(r) Demand-side costs, including the costs of developing, implementing and evaluating customer energy efficiency and demand response programs. Costs incurred from May 2008 through September 2008 are being amortized over ten years, beginning in March 2009. Costs incurred from October 2008 through December 2009 are being amortized over six years, beginning in July 2010. The amortization period for the costs incurred after December 2009 will be determined in UE s pending electric rate case.
(s) Reserve for workers compensation claims.
(t) A regulatory tracking mechanism for the difference between the level of bad debt expense incurred by AIC under GAAP and the level of such costs built into electric and natural gas rates. The under-recovery relating to 2009 will be recovered from customers from June 2010 through May 2011.
(u) UE s costs incurred to enter into and maintain the 2009 Multiyear Credit Agreements, prior to their termination in 2010. These costs are being amortized over two years, beginning in July 2010, as approved by the May 2010 MoPSC electric rate order. These costs are being amortized to construction work in progress, which will be subsequently depreciated when assets are placed into service.
(v) Cost incurred for the 2009 voluntary and involuntary separation programs. The UE-related costs are being amortized over three years, beginning in July 2010, as approved by the May 2010 MoPSC electric rate order. The AIC-related costs are being amortized over three years, beginning in May 2010, as approved by the April 2010 ICC electric and natural gas rate order.
(w) The MoPSC s May 2010 electric rate order allowed UE to recover its portion of Ameren s September 2009 common stock issuance costs. These costs are being amortized over five years, beginning in July 2010.
(x) The MoPSC s May 2010 electric rate order allowed UE to continue recording an allowance for funds used during construction for pollution control equipment at its Sioux plant until the earlier of January 2012 or when the cost of that equipment is placed in customer rates. The amortization period will be determined in a future electric rate case.
(y) Includes costs related to AIC s November 2007 electric and natural gas delivery service rate cases. The costs associated with AIC s electric delivery service rate cases are being amortized over a three-year period; the costs associated with AIC s natural gas delivery service rate cases are being amortized over a five-year period, as approved in the 2008 ICC rate order. At UE, the balance includes funding for low-income assistance, weatherization, and other miscellaneous items.
(z) Over-recovered fuel costs for the accumulation period from March 2009 through May 2009. Customer refunds began in October 2009 and concluded in September 2010.
(aa) Deferral of commodity-related derivative MTM gains.

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(bb) Included in Other Current Liabilities on UE s balance sheet.
(cc) Unamortized portion of investment tax credit and federal excess deferred taxes. See Note 13 Income Taxes for amortization period.
(dd) Estimated funds collected for the eventual dismantling and removal of plant from service, net of salvage value, upon retirement related to our rate-regulated operations. See discussion in Note 1 Summary of Significant Accounting Policies Asset Retirement Obligations.
(ee) The deferral of gains on emission allowance vintage swaps UE entered into during 2005. This gain will be amortized as emission allowances are used.
(ff) A regulatory tracking mechanism for the difference between the level of vegetation management and infrastructure inspection costs incurred by UE under GAAP and the level of such costs built into electric rates. UE s vegetation management and infrastructure inspection costs from October 2008 through February 2010 were less than the amount allowed in base rates. The over-recovery incurred during that time period is being amortized over three years, beginning in July 2010. UE s vegetation management and infrastructure inspection costs from July 2010 through December 2010 were also less than the amount allowed in base rates. The amortization period for this over-recovery will be determined in a future UE electric rate case.
(gg) A regulatory tracking mechanism for the difference between the level of bad debt expense incurred by AIC under GAAP and the level of such costs built into electric and natural gas rates. The over-recovery relating to 2009 will be refunded to customers starting in June 2010 through May 2011. The over-recovery relating to 2010 will be refunded to customers starting in June 2011 through May 2012.
(hh) A regulatory tracking mechanism for the difference between the level of pension and postretirement benefit costs incurred by UE under GAAP and the level of such costs built into electric rates.
(ii) A regulatory tracking mechanism that allows AIC to recover its electric and natural gas costs associated with developing, implementing and evaluating customer energy efficiency and demand response programs. This over-recovery will be refunded to customers over the following 12 months after the plan year.

UE and AIC continually assess the recoverability of their 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. To the extent that payments of regulatory liabilities are no longer probable, the amounts are credited to earnings.

NOTE 3 PROPERTY AND PLANT, NET

The following table presents property and plant, net, for each of the Ameren Companies at December 31, 2010, and 2009:

	Ameren(a)(b)	UE(b)	AIC	Genco
2010:				
Property and plant, at original cost:				
Electric	**$ 24,069**	**$ 14,745**	**$ 4,436**	**$ 3,572**
Gas	**1,661**	**374**	**1,286**	**-**
Other	**424**	**91**	**61**	**48**
	26,154	**15,210**	**5,783**	**3,620**
Less: Accumulated depreciation and amortization	**9,194**	**6,052**	**1,250**	**1,518**
	16,960	**9,158**	**4,533**	**2,102**
Construction work in progress:				
Nuclear fuel in process	**259**	**259**	**-**	**-**
Other	**634**	**358**	**43**	**146**
Property and plant, net	**$ 17,853**	**$ 9,775**	**$ 4,576**	**$ 2,248**
2009:				
Property and plant, at original cost:				
Electric	$ 22,486	$ 13,627	$ 4,279	$ 3,295
Gas	1,583	363	1,220	-
Other	406	85	20	48
	24,475	14,075	5,519	3,343
Less: Accumulated depreciation and amortization	8,787	5,760	1,228	1,450
	15,688	8,315	4,291	1,893
Construction work in progress:				
Nuclear fuel in process	271	271	-	-
Other	1,651	999	63	444
Property and plant, net	$ 17,610	$ 9,585	$ 4,354	$ 2,337

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries as well as intercompany eliminations.
(b) Amounts in Ameren and UE include two electric generation CTs under two separate capital lease agreements. The gross asset value of those agreements was $228 million and $226 million at December 31, 2010, and 2009, respectively. The total accumulated depreciation associated with the two CTs was $46 million and $41 million at December 31, 2010, and 2009, respectively.

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The following table provides accrued capital expenditures at December 31, 2010, 2009, and 2008, which represent noncash investing activity excluded from the statements of cash flows:

	Ameren[(a)]	UE	AIC	Genco
2010	**$ 79**	**$ 53**	**$ 15**	**$ 8**
2009	143	86	29	23
2008	213	110	21	41

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

NOTE 4 CREDIT FACILITY BORROWINGS AND LIQUIDITY

The liquidity needs of the Ameren Companies are typically supported through the use of available cash, short-term intercompany borrowings, drawings under committed bank credit facilities, or commercial paper issuances.

The following table summarizes the borrowing activity and relevant interest rates under the 2010 Missouri Credit Agreement described below for the year ended December 31, 2010, and excludes letters of credit issued under the credit agreement:

2010 Missouri Credit Agreement ($800 million)	**Ameren (Parent)**	**UE**	**Total**
2010:			
Average daily borrowings outstanding during 2010[(a)]	**$ 195**	**$ -**	**$ 195**
Outstanding credit facility borrowings at period end	**340**	**-**	**340**
Weighted-average interest rate during 2010[(a)]	**2.31%**	**-**	**2.31%**
Peak credit facility borrowings during 2010[(a)(b)]	**$ 380**	**$ -**	**$ 380**
Peak interest rate during 2010[(a)]	**2.31%**	**-**	**2.31%**

(a) Calculated from the September 10, 2010, inception date through December 31, 2010.
(b) The timing of peak credit facility borrowings varies by company and therefore the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

The following table summarizes the borrowing activity and relevant interest rates under the 2010 Genco Credit Agreement described below for the year ended December 31, 2010:

2010 Genco Credit Agreement ($500 million)	**Ameren (Parent)**	**Genco**	**Total**
2010:			
Average daily borrowings outstanding during 2010[(a)]	**$ 36**	**$ 54**	**$ 90**
Outstanding credit facility borrowings at period end	**-**	**100**	**100**
Weighted-average interest rate during 2010[(a)]	**2.30%**	**2.31%**	**2.31%**
Peak credit facility borrowings during 2010[(a)(b)]	**$ 385**	**$ 100**	**$ 385**
Peak interest rate during 2010[(a)]	**2.31%**	**2.31%**	**2.31%**

(a) Calculated from the September 10, 2010, inception date through December 31, 2010.
(b) The timing of peak credit facility borrowings varies by company and therefore the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

Ameren and AIC did not borrow under the 2010 Illinois Credit Agreement during 2010.

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The following table summarizes the borrowing activity and relevant interest rates under the 2009 Multiyear Credit Agreement, which terminated on September 10, 2010, for the years ended December 31, 2010, and 2009 and excludes letters of credit issued under the credit agreement:

2009 Multiyear Credit Agreement (Terminated)	Ameren (Parent)	UE	Genco	Total
2010:				
Average daily borrowings outstanding during 2010[(a)]	**$ 567**	**$ -**	**$ -**	**$ 567**
Outstanding credit facility borrowings at period end	**-**	**-**	**-**	**-**
Weighted-average interest rate during 2010[(a)]	**3.12%**	**-**	**-**	**3.12%**
Peak credit facility borrowings during 2010[(a)(b)]	**$ 712**	**$ -**	**$ -**	**$ 712**
Peak interest rate during 2010[(b)]	**5.50%**	**-**	**-**	**5.50%**
2009:				
Average daily borrowings outstanding during 2009	$ 307	$ 266	$ 54	$ 627
Outstanding credit facility borrowings at period end	646	-	-	646
Weighted-average interest rate during 2009	2.15%	1.72%	2.70%	2.02%
Peak credit facility borrowings during 2009[(b)]	$ 699	$ 457	$ 133	$ 940
Peak interest rate during 2009	5.50%	5.50%	3.56%	5.50%

(a) Calculated through the termination date.
(b) The timing of peak credit facility borrowings varies by company. Therefore, the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

The following table summarizes the borrowing activity and relevant interest rates under the 2009 $150 million Supplemental Credit Agreement, which expired on July 14, 2010, for the year ended December 31, 2010 and 2009:

2009 Supplemental Credit Agreement (Expired)	Ameren (Parent)	UE	Genco	Total
2010:				
Average daily borrowings outstanding during 2010[(a)]	**$ 74**	**$ -**	**$ -**	**$ 74**
Outstanding credit facility borrowings at period end	**-**	**-**	**-**	**-**
Weighted-average interest rate during 2010[(a)]	**3.53%**	**-**	**-**	**3.53%**
Peak credit facility borrowings during 2010[(a)(b)]	**$ 93**	**$ -**	**$ -**	**$ 93**
Peak interest rate during 2010[(b)]	**5.50%**	**-**	**-**	**5.50%**
2009:				
Average daily borrowings outstanding during 2009	$ 42	$ 20	$ 12	$ 74
Outstanding credit facility borrowings at period end	84	-	-	84
Weighted-average interest rate during 2009	3.58%	3.62%	3.52%	3.56%
Peak credit facility borrowings during 2009[(b)]	$ 91	$ 53	$ 17	$ 109
Peak interest rate during 2009	5.50%	5.50%	3.56%	5.50%

(a) Calculated through the expiration date.
(b) The timing of peak credit facility borrowings varies by company and therefore the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

The following table summarizes the borrowing activity and relevant interest rates under the $800 million 2009 Illinois Credit Agreement, which terminated on September 10, 2010, for the year ended December 31, 2010 and 2009:

2009 Illinois Credit Agreement (Terminated)	Ameren (Parent)	AIC	Total
2010:			

Average daily borrowings outstanding during 2010[a]	**$ 8**	**$ -**	**$ 8**
Outstanding credit facility borrowings at period end	**-**	**-**	**-**
Weighted-average interest rate during 2010[a]	**3.48%**	**-**	**3.48%**
Peak credit facility borrowings during 2010[a][b]	**$ 100**	**$ -**	**$ 100**
Peak interest rate during 2010[b]	**3.48%**	**-**	**3.48%**
2009:			
Average daily borrowings outstanding during 2009	$ 68	$ -	$ 68
Outstanding credit facility borrowings at period end	100	-	100
Weighted-average interest rate during 2009	3.54%	-	3.54%
Peak credit facility borrowings during 2009[b]	$ 200	$ -	$ 200
Peak interest rate during 2009	3.56%	-	3.56%

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(a) Calculated through the termination date.
(b) The timing of peak credit facility borrowings varies by company. Therefore, the amounts presented by company may not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

2010 Credit Agreements

Ameren and certain of its subsidiaries entered into multiyear credit facility agreements with a large and diverse group of lenders. These facilities cumulatively provide $2.1 billion of credit through September 10, 2013, which date is inclusive of the UE borrowing sublimit extension periods provided for in the 2010 Missouri Credit Agreement, as discussed below. The facilities currently include 25 international, national, and regional lenders, with no lender providing more than $125 million of credit in aggregate.

On September 10, 2010, Ameren and UE entered into the $800 million 2010 Missouri Credit Agreement. On September 10, 2010, Ameren and Genco entered into the $500 million 2010 Genco Credit Agreement. Together, the 2010 Missouri Credit Agreement and the 2010 Genco Credit Agreement replaced the 2009 Multiyear Credit Agreements under which Ameren, UE and Genco were borrowers. The 2009 Multiyear Credit Agreement was terminated contemporaneously with the effectiveness of the 2010 Missouri Credit Agreement and the 2010 Genco Credit Agreement.

Also on September 10, 2010, Ameren and AIC, as successor company to CIPS, CILCO and IP, entered into the $800 million 2010 Illinois Credit Agreement. The 2010 Illinois Credit Agreement replaced the 2009 Illinois Credit Agreement, which was terminated when the 2010 Illinois Credit Agreement became effective.

The obligations of each borrower under the respective 2010 Credit Agreements to which it is a party are several and not joint, and, except under limited circumstances relating to expenses and indemnities, the obligations of UE, AIC and Genco under the respective 2010 Credit Agreements are not guaranteed by Ameren or any other subsidiary of Ameren. The maximum aggregate amount available to each borrower under each facility is shown in the following table (such amount being such borrower s Borrowing Sublimit):

	2010 Missouri Credit Agreement	**2010 Genco Credit Agreement**	**2010 Illinois Credit Agreement**
Ameren	$ 500	$ 500	$ 300
UE	500	(a)	(a)
AIC	(a)	(a)	800
Genco	(a)	500	(a)

(a) Not applicable.

Ameren has the option to seek additional commitments from existing or new lenders to increase the total facility size of the 2010 Credit Agreements up to the following maximum amounts: 2010 Missouri Credit Agreement $1.0 billion; 2010 Genco Credit Agreement $625 million;

and 2010 Illinois Credit Agreement $1.0 billion. Each of the 2010 Credit Agreements will mature and expire on September 10, 2013. In February 2011, AIC received approval from the ICC to extend the expiration of its Borrowing Sublimit under the 2010 Illinois Credit Agreement to September 10, 2013. The Borrowing Sublimit of UE under the 2010 Missouri Credit Agreement will mature and expire on September 9, 2011, subject to extension thereof on a 364-day basis, as requested by UE and approved by the lenders, or for a longer period upon receipt of any and all required federal or state regulatory approvals, as permitted under the 2010 Missouri Credit Agreement, but in no event later than September 10, 2013. UE is seeking regulatory approval to extend the maturity dates of its Borrowing Sublimit under the 2010 Missouri Credit Agreement. If and when such regulatory approval is received, no lender approval will be required for the extension to take effect. The principal amount of each revolving loan owed by a borrower under any of the 2010 Credit Agreements to which it is a party will be due and payable no later than the final maturity relating to such borrower under such 2010 Credit Agreements.

The obligations of all borrowers under the 2010 Credit Agreements are unsecured. Loans are available on a revolving basis under each of the 2010 Credit Agreements and may be repaid and, subject to satisfaction of the conditions to borrowing, reborrowed from time to time. At the election of each borrower, the interest rates on such loans will be the alternate base rate (ABR) plus the margin applicable to the particular borrower and/or the Eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined by the borrower s long-term unsecured credit ratings or, if no such ratings are then in effect, the borrower s corporate/issuer ratings then in effect. Letters of credit in an aggregate undrawn face amount not to exceed 25% of the applicable aggregate commitment under the respective 2010 Credit Agreements are also available for issuance for the account of the borrowers thereunder (but within the $2.1 billion overall combined facility borrowing limitations of the 2010 Credit Agreements).

Upon closing, the borrowers used some of the credit capacity available under the 2010 Credit Agreements to repay amounts owed under the 2009 Multiyear Credit Agreement and the 2009 Illinois Credit Agreement. The borrowers will use the proceeds from any additional borrowings under the 2010 Credit Agreements for general corporate purposes, including working capital and commercial paper liquidity support, the funding of loans under the Ameren money pool arrangements or other short-term intercompany loan arrangements, and the payment of fees and expenses incurred in connection with the 2010 Credit Agreements.

Based on outstanding borrowings under the 2010 Credit Agreements (and also considering reductions of borrowing capacity for $15 million of letters of credit issued and $269 million of commercial paper borrowings), the aggregate available amount under the 2010 Credit Agreements at December 31, 2010, was $1.38 billion.

Other Agreements

On June 2, 2010, Ameren entered into a $20 million revolving credit facility ($20 Million Facility) that matures on June 1, 2012. The $20 Million Facility has been fully drawn since June 15, 2010. Borrowings under the $20 Million Facility bear interest at a rate equal to the applicable LIBOR plus 2.25% per annum. The obligations of Ameren under the $20 Million Facility are unsecured. No subsidiary of Ameren is a party to, guarantor of, or borrower under the facility.

On January 21, 2009, Ameren entered into a $20 million term loan agreement due January 20, 2010, which was fully drawn on January 21, 2009. The average annual interest rate for borrowing under the $20 million term loan agreement was 2.03% during the year ended December 31, 2009. This term loan agreement was repaid at maturity in January 2010.

Commercial Paper

The 2010 Credit Agreements are used to support Ameren s and UE s commercial paper programs. Ameren may at its discretion use any of the 2010 Credit Agreements to support its commercial paper program, subject to its applicable sublimit. At December 31, 2010, Ameren had $269 million of commercial paper outstanding, which reduced the available amounts under these facilities. During the six months, from July through December, that the program was in use during 2010, Ameren had average daily commercial paper balances outstanding of $185 million with a weighted-average interest rate of 0.94%. The peak short-term commercial paper outstanding and peak interest rate during the six months was $366 million and 1.46%, respectively.

Indebtedness Provisions and Other Covenants

The information below presents a summary of the Ameren Companies compliance with indebtedness provisions and other covenants.

The 2010 Credit Agreements contain conditions to borrowings and issuances of letters of credit, including the absence of default or unmatured default, material accuracy of representations and warranties (excluding any representation after the closing date as to the absence of material adverse change and material litigation), and required regulatory authorizations. In addition, solely as it relates to borrowings under the 2010 Illinois Credit Agreement, it is a condition precedent to any such borrowing that, at the time of and after giving effect to such borrowing, the borrower will not be in violation of any limitation on its ability to incur unsecured indebtedness

contained in its articles of incorporation. The 2010 Credit Agreements also contain nonfinancial covenants, including restrictions on the ability to incur liens, to transact with affiliates, to dispose of assets, to make investments in or transfer assets to its affiliates, and to merge with other entities.

The 2010 Credit Agreements require each of Ameren, UE, AIC and Genco to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a defined calculation set forth in the agreements. As of December 31, 2010, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the 2010 Credit Agreements, were 50%, 47%, 42% and 48%, for Ameren, UE, AIC and Genco, respectively. These ratios include the effect of the goodwill and other asset impairment charges for Ameren and Genco recorded in 2010. See Note 17 Goodwill and Other Asset Impairments for additional information. In addition, under the 2010 Genco Credit Agreement and the 2010 Illinois Credit Agreement, Ameren is required to maintain a ratio of consolidated funds from operations plus interest expense to consolidated interest expense of 2.0 to 1, to be calculated quarterly, as of the end of the most recent four fiscal quarters then ending, in accordance with the 2010 Genco Credit Agreement and the 2010 Illinois Credit Agreement, as applicable. Ameren s ratio as of December 31, 2010 was 4.8 to 1. Failure of a borrower to satisfy a financial covenant constitutes an immediate default under the applicable 2010 Credit Agreement.

The 2010 Credit Agreements contain default provisions. UE and Genco are no longer borrowers within the same credit agreement, as they were under the 2009 Multiyear Credit Agreement, and a default by one such subsidiary borrower will not trigger a default by the other under the applicable 2010 Credit Agreements. Defaults under the 2010 Credit Agreements apply separately to each borrower; except however, that a default by UE, AIC or Genco under any of the 2010 Credit Agreements will also constitute a default by Ameren under such agreement. Defaults include a cross default with respect to a borrower under the applicable 2010 Credit Agreements to the occurrence of a default by such borrower under any other agreement covering outstanding indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries and nonmaterial subsidiaries) in excess of $25 million in the aggregate. Any default of Ameren under any 2010 Credit Agreement that exists solely as a result of a default by UE, AIC or Genco thereunder will not constitute a default under any other 2010 Credit Agreement while Ameren is otherwise in compliance with all of its obligations under such other 2010 Credit Agreement. Further, a default at the Ameren level under any 2010 Credit Agreement does not trigger a default by UE, AIC or Genco under such agreement.

The $20 Million Facility requires Ameren to maintain consolidated indebtedness of not more than 65% of its consolidated capitalization pursuant to a defined calculation set forth in the agreement. As of December 31, 2010, Ameren s consolidated indebtedness ratio, calculated in accordance with the provisions of the $20 Million Facility was 50%. Failure by Ameren to satisfy this covenant would constitute an immediate default under the $20 Million Facility but, given the size of the facility, would not trigger an Ameren default under any of the 2010 Credit Agreements or Ameren s indenture.

None of the Ameren Companies credit facilities or financing arrangements contains credit rating triggers that would cause an event of default or acceleration of repayment of outstanding balances. At December 31, 2010, management believes that the Ameren Companies were in compliance with their credit facilities provisions and covenants.

Money Pools

Ameren has money pool agreements with and among its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained for utility and non-state-regulated entities. Ameren Services is responsible for the operation and administration of the money pool agreements.

Utility

Through the utility money pool, the pool participants may access the committed credit facilities. Ameren Services administers the utility money pool and tracks internal and external funds separately. Ameren and certain non-state-regulated subsidiaries may participate in the utility money pool only as lenders. Internal funds are surplus funds contributed to the utility money pool from participants. The primary sources of external funds for the utility money pool are the 2010 Credit Agreements. The total amount available to the pool participants from the utility money pool at any given time is reduced by the amount of borrowings by their affiliates, but increased to the extent that the pool participants have surplus funds or contribute funds from other external sources. The availability of funds is also determined by funding requirement limits established by regulatory authorizations. Participants receiving a loan under the utility money pool agreement must repay the principal amount of such loan, together with accrued interest. The rate of interest depends on the composition of internal and external funds in the utility money pool. The average interest rate for borrowing under the utility money

pool for the year ended December 31, 2010, was 0.18% (2009 0.19%).

Non-state-regulated Subsidiaries

Ameren Services, Resources Company, Genco, AERG, Marketing Company, and other non-state-regulated Ameren subsidiaries have the ability, subject to Ameren parent company authorization and applicable regulatory short-term borrowing authorizations, to access funding from the 2010 Credit Agreements through a non-state-regulated subsidiary money pool agreement. The total amount available to the pool participants at any time is reduced by borrowings made by Ameren s subsidiaries, but is increased to the extent that other pool participants advance surplus funds to the non-state-regulated subsidiary money pool or remit funds from other external sources. See the discussion above for the amount available under the 2010 Credit Agreements at December 31, 2010. The non-state-regulated subsidiary money pool was established to coordinate and to provide short-term cash and working capital for Ameren s non-state-regulated activities. Participants receiving a loan under the non-state-regulated subsidiary money pool agreement must repay the principal amount of such loan, together with accrued interest. The rate of interest depends on the composition of internal and external funds in the non-state-regulated subsidiary money pool. The average interest rate for borrowing under the non-state-regulated subsidiary money pool for the year ended December 31, 2010, was 0.77% (2009 1.64%).

See Note 14 Related Party Transactions for the amount of interest income and expense from the money pool arrangements recorded by the Ameren Companies for the years ended December 31, 2010, 2009, and 2008.

Unilateral Borrowing Agreement

In addition, a unilateral borrowing agreement exists between Ameren, AIC, and Ameren Services, which enables AIC to make short-term borrowings directly from Ameren. The aggregate amount of borrowings outstanding at any time by AIC under the unilateral borrowing agreement and the utility money pool agreement, together with any outstanding external credit facility borrowings by AIC, may not exceed $500 million, pursuant to authorization from the ICC. AIC is not currently borrowing under the unilateral borrowing agreement. Ameren Services is responsible for operation and administration of the unilateral borrowing agreement.

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NOTE 5 LONG-TERM DEBT AND EQUITY FINANCINGS

The following table presents long-term debt outstanding for the Ameren Companies as of December 31, 2010, and 2009:

	2010	2009
Ameren (Parent):		
8.875% Senior unsecured notes due 2014	**$ 425**	$ 425
Less: Unamortized discount and premium	**(2)**	(2)
Long-term debt, net	**$ 423**	$ 423
UE:		
First mortgage bonds:[a]		
5.25% Senior secured notes due 2012[b]	**$ 173**	$ 173
4.65% Senior secured notes due 2013[b]	**200**	200
5.50% Senior secured notes due 2014[b]	**104**	104
4.75% Senior secured notes due 2015[b]	**114**	114
5.40% Senior secured notes due 2016[b]	**260**	260
6.40% Senior secured notes due 2017[b]	**425**	425
6.00% Senior secured notes due 2018[b]	**250**	250
5.10% Senior secured notes due 2018[b]	**200**	200
6.70% Senior secured notes due 2019[b]	**450**	450
5.10% Senior secured notes due 2019[b]	**300**	300
5.00% Senior secured notes due 2020[b]	**85**	85
5.45% Series due 2028[d]	**44**	44
5.50% Senior secured notes due 2034[b]	**184**	184
5.30% Senior secured notes due 2037[b]	**300**	300
8.45% Senior secured notes due 2039[b]	**350**	350
Environmental improvement and pollution control revenue bonds: [a][b][d][e]		
1992 Series due 2022	**47**	47
1998 Series A due 2033	**60**	60
1998 Series B due 2033	**50**	50
1998 Series C due 2033	**50**	50
Subordinated deferrable interest debentures:		
7.69% Series A due 2036 66	**-**	66
Capital lease obligations:		
City of Bowling Green capital lease (Peno Creek CT)	**74**	78
Audrain County capital lease (Audrain County CT)	**240**	240
Total long-term debt, gross	**3,960**	4,030
Less: Unamortized discount and premium	**(6)**	(8)
Less: Maturities due within one year	**(5)**	(4)
Long-term debt, net	**$ 3,949**	$ 4,018

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	2010	2009
AIC:		
First mortgage bonds:[(a)]		
6.625% Senior secured notes due 2011[(b)]	**$ 150**	$ 150
8.875% Senior secured notes due 2013[(c)]	**150**	150
6.20% Senior secured notes due 2016[(c)]	**54**	54
6.25% Senior secured notes due 2016[(b)]	**75**	75
6.125% Senior secured notes due 2017[(b)]	**250**	250
7.61% Series 1997-2 due 2017	**-**	40
6.25% Senior secured notes due 2018[(b)]	**337**	337
9.75% Senior secured notes due 2018[(b)]	**400**	400
6.125% Senior secured notes due 2028[(b)]	**60**	60
6.70% Senior secured notes due 2036[(b)]	**61**	61
6.70% Senior secured notes due 2036[(c)]	**42**	42
Environmental improvement and pollution control revenue bonds:		
6.20% Series 1992B due 2012[(a)(d)]	**1**	1
2000 Series A 5.50% due 2014[(d)]	**51**	51
5.90% Series 1993 due 2023[(a)(d)]	**32**	32
5.70% 1994A Series due 2024[(a)(d)]	**36**	36
1993 Series C-1 5.95% due 2026	**35**	35
1993 Series C-2 5.70% due 2026	**8**	8
1993 Series B-1 due 2028[(e)]	**17**	17
5.40% 1998A Series due 2028[(a)(d)]	**19**	19
5.40% 1998B Series due 2028[(a)(d)]	**33**	33
Fair-market value adjustments	**5**	6
Total long-term debt, gross	**1,816**	1,857
Less: Unamortized discount and premium	**(9)**	(10)
Less: Maturities due within one year	**(150)**	-
Long-term debt, net	**$ 1,657**	$ 1,847
Genco:		
Unsecured notes:		
Senior notes Series D 8.35% due 2010	**$ -**	$ 200
Senior notes Series F 7.95% due 2032	**275**	275
Senior notes Series H 7.00% due 2018	**300**	300
Senior notes Series I 6.30% due 2020	**250**	250
Total long-term debt, gross	**825**	1,025
Less: Unamortized discount and premium	**(1)**	(2)
Less: Maturities due within one year	**-**	(200)
Long-term debt, net	**$ 824**	$ 823
Ameren consolidated long-term debt, net	**$ 6,853**	$ 7,111

(a) At December 31, 2010, most property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued. Accordingly, substantially all of the long-term debt issued by UE is secured by liens on substantially all of UE s property and franchises. Substantially all long term debt issued by AIC is either secured by a lien under the CILCO bond indenture on substantially all the property and franchises of the former CILCO or secured by a lien under the IP bond indenture on substantially all the property and franchises of the former CIPS and IP.

(b) These notes are collaterally secured by first mortgage bonds issued by UE under its mortgage bond indenture or by AIC under the IP bond mortgage indenture and will remain secured at each company until the following series are no longer outstanding with respect to that company: UE 5.45% Series due 2028 (currently callable at 100% of par), 6.00% Series due 2018, 6.70% Series due 2019, and 8.45% Series due 2039; AIC 6.125% Series due 2017, 6.25% Series due 2018, 9.75% Series due 2018, 5.70% 1994A Series due 2024 (currently callable at 100% of par), 5.40% 1998A Series due 2028 (currently callable at 100% of par), and 5.40% 1998B Series due 2028 (currently callable at 100% of par).

(c) These notes are collaterally secured by first mortgage bonds issued by AIC under the CILCO bond indenture and will remain secured until the following series are no longer outstanding: 6.20% Series 1992B due 2012 (currently callable at 100% of par), 5.90% Series 1993 due 2023 (currently callable at 100% of par), and 8.875% Series due 2013.

(d) Environmental improvement or pollution control series secured by first mortgage bonds. In addition, all of the series except UE s 5.45% Series and AIC s 6.20% Series 1992B and 5.90% Series 1993 bonds are backed by an insurance guarantee policy.

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(e) Interest rates, and the periods during which such rates apply, vary depending on our selection of certain defined rate modes. Maximum interest rates could range up to 18% depending upon the series of bonds. The average interest rates for the years 2010 and 2009 were as follows:

	2010	2009
UE 1992 Series	0.47%	0.68%
UE 1998 Series A	0.71%	0.99%
UE 1998 Series B	0.73%	1.02%
UE 1998 Series C	0.74%	0.99%
AIC 1993 Series B-1	0.59%	1.34%

The following table presents the aggregate maturities of long-term debt, including current maturities, for the Ameren Companies at December 31, 2010:

	Ameren (Parent)[a]	UE[a]	AIC[a][b]	Genco[a]	Ameren Consolidated
2011	$ -	$ 5	$ 150	$ -	$ 155
2012	-	178	1	-	179
2013	-	205	150	-	355
2014	425	109	51	-	585
2015	-	120	-	-	120
Thereafter	-	3,343	1,459	825	5,627
Total	$ 425	$ 3,960	$ 1,811	$ 825	$ 7,021

(a) Excludes unamortized discount and premium of $2 million, $6 million, $9 million and $1 million at Ameren (Parent), UE, AIC and Genco, respectively.
(b) Excludes $5 million related to AIC s long-term debt fair-market value adjustments, which are being amortized to interest expense over the remaining life of the debt.

All of the Ameren Companies expect to fund maturities of long-term debt, short-term borrowings, credit facility borrowings and contractual obligations through a combination of cash flow from operations and external financing. See Note 4 Credit Facility Borrowings and Liquidity for a discussion of external financing availability.

In November 2008, Ameren, as a well-known seasoned issuer, along with AIC s predecessor companies, (CIPS, CILCO and IP), and Genco, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in November 2011. In June 2008, UE, as a well-known seasoned issuer, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in June 2011.

All classes of UE s and AIC s preferred stock are entitled to cumulative dividends and have voting rights. The following table presents the outstanding preferred stock of UE and AIC that is not subject to mandatory redemption. The preferred stock is redeemable, at the option of the issuer, at the prices presented as of December 31, 2010 and 2009:

		Redemption Price (per share)	2010	2009
UE:				
Without par value and stated value of $100 per share, 25 million shares authorized				
$3.50 Series	130,000 shares	$ 110.00	**$ 13**	$ 13
$3.70 Series	40,000 shares	104.75	**4**	4
$4.00 Series	150,000 shares	105.625	**15**	15
$4.30 Series	40,000 shares	105.00	**4**	4
$4.50 Series	213,595 shares	110.00[a]	**21**	21
$4.56 Series	200,000 shares	102.47	**20**	20
$4.75 Series	20,000 shares	102.176	**2**	2
$5.50 Series A	14,000 shares	110.00	**1**	1
$7.64 Series[b]			**-**	33

Total	**$ 80**	$ 113

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		Redemption Price (per share)	2010	2009
AIC:				
With par value of $100 per share, 2 million shares authorized				
4.00% Series	144,275 shares	$ 101.00	**$ 14**	$ 15
4.08% Series	45,224 shares	103.00	**5**	12
4.20% Series	23,655 shares	104.00	**2**	7
4.25% Series	50,000 shares	102.00	**5**	5
4.26% Series	16,621 shares	103.00	**2**	5
4.42% Series	16,190 shares	103.00	**2**	5
4.50% Series(b)			**-**	11
4.64% Series(b)			**-**	8
4.70% Series	18,429 shares	103.00	**2**	7
4.90% Series	73,825 shares	102.00	**7**	8
4.92% Series	49,289 shares	103.50	**5**	5
5.16% Series	50,000 shares	102.00	**5**	5
6.625% Series	124,273.75 shares	100.00	**12**	12
7.75% Series	4,542 shares	100.00	**1**	10
Total			**$ 62**	$ 115
Less: Shares of AIC preferred stock owned by Ameren			**-**	(33)
Total Ameren			**$ 142**	$ 195

(a) In the event of voluntary liquidation, $105.50.
(b) Series redeemed in 2010.

Pursuant to the AIC Merger: (i) every two shares of each series of IP preferred stock outstanding immediately prior to the AIC Merger were automatically converted into one share of a newly created series of AIC preferred stock having the same payment and redemption terms as the existing series of IP preferred stock, except to the extent that IP preferred stockholders exercised their dissenters rights in accordance with Illinois law; and (ii) each outstanding share of CIPS common and preferred stock remained outstanding, except to the extent that CIPS preferred stockholders exercised their dissenters rights in accordance with Illinois law. Stockholders holding 8,337 shares and 423 shares of CIPS and IP preferred stock, respectively, exercised their dissenter s rights.

In addition, the Ameren Companies have classes of preferred stock that are authorized but no shares of which are outstanding. Ameren has 100 million shares of $0.01 par value preferred stock authorized, with no shares outstanding. UE has 7.5 million shares of $1 par value preference stock authorized, with no such preference stock outstanding. AIC has 2.6 million shares of no par value preferred stock authorized, with no shares outstanding.

Ameren

A Form S-3 registration statement was filed by Ameren with the SEC in July 2008, and amended and supplemented in December 2010, authorizing the offering of six million additional shares of its common stock under the DRPlus. Shares of common stock sold under DRPlus are, at Ameren s option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated transactions. Ameren is currently selling newly issued shares of its common stock under DRPlus.

Ameren is also selling newly issued shares of common stock under its 401(k) plan pursuant to an effective SEC Form S-8 registration statement. Under DRPlus and its 401(k) plan, Ameren issued 3.0 million, 3.2 million, and 4.0 million shares of common stock in 2010, 2009, and 2008, respectively, which were valued at $80 million, $82 million, and $154 million for the respective years.

In May 2009, Ameren issued $425 million of 8.875% senior unsecured notes due May 15, 2014, with interest payable semiannually on May 15 and November 15 of each year, beginning November 15, 2009. Ameren received net proceeds of $420 million, which were used, together with other corporate funds, to repay borrowings under its $300 million term loan agreement and, by way of a capital contribution to CILCORP, to provide funds for CILCORP to repay its outstanding 8.70% senior notes on their due date of October 15, 2009.

In September 2009, Ameren issued and sold 21.85 million shares of its common stock at $25.25 per share, for proceeds of $535 million, net of $17 million of issuance costs. Ameren used the net offering proceeds to make investments in its rate-regulated utility subsidiaries in the form of equity capital contributions to UE and AIC of $436 million and $99 million, respectively.

In October 2009, $124 million of CILCORP s 8.70% senior notes matured and were retired.

In December 2009, CILCORP paid $256 million, including tender offer and consent payments and accrued interest, in connection with the repurchase and cancellation of $208 million principal amount outstanding of its 9.375% senior bonds. After the repurchase, approximately $2 million principal amount of senior bonds remained outstanding. Sufficient consents were received to approve the adoption of amendments to eliminate certain restrictive covenants to the related indenture. As a result of this cancellation, fair-market value adjustments related to the senior bonds were reduced by $44 million during 2009.

In February 2010, CILCORP completed a covenant defeasance of its remaining outstanding 9.375% senior bonds due 2029 by depositing approximately $3 million in U.S. government obligations and cash with the indenture trustee. This deposit will be used solely to satisfy the principal and remaining interest obligations on these bonds. In connection with this covenant defeasance, the lien on the capital stock of CILCO securing these bonds was released.

UE

In March 2009, UE issued $350 million of 8.45% senior secured notes due March 15, 2039, with interest payable semiannually on March 15 and September 15 of each year, beginning in September 2009. These notes are secured by first mortgage bonds. UE received net proceeds of $346 million, which were used to repay short-term debt. In connection with this issuance of $350 million of senior secured notes, UE agreed that, so long as these senior secured notes are outstanding, it would not, prior to maturity, cause a first mortgage bond release date to occur.

In August 2010, UE redeemed all of the 330,000 outstanding shares of its $7.64 Series preferred stock at $100.85 per share, plus accrued and unpaid dividends.

In September 2010, UE redeemed all $66 million of its 7.69% Series A subordinated deferrable interest debentures at a redemption price of 102.692% of the principal amount plus accrued interest.

AIC

In June 2009, $250 million of AIC s (formerly IP s) 7.50% series first mortgage bonds matured and were retired.

In August 2010, AIC (formerly CILCO) redeemed all of the 111,264 outstanding shares of its 4.50% Series preferred stock at $110 per share and all of the 79,940 shares of its 4.64% Series preferred stock at $102 per share, plus, in each case, accrued and unpaid dividends. These preferred shares were redeemed in connection with the AIC Merger.

In September 2010, AIC (formerly CIPS) redeemed all $40 million of its 7.61% Series 1997-2 first mortgage bonds at a redemption price of 101.52% of the principal amount, plus accrued interest. These bonds were redeemed in connection with the AIC Merger.

In September 2010, Ameren contributed to the capital of AIC (formerly IP), without the payment of any consideration, all of the IP preferred stock owned by Ameren ($33 million). IP cancelled these preferred shares. This transaction was in connection with the AIC Merger.

See Note 16 Corporate Reorganization and Discontinued Operations for additional information.

Genco

In November 2009, Genco issued $250 million of 6.30% senior unsecured notes due April 1, 2020, with interest payable semiannually on April 1 and October 1 of each year, beginning in April 2010. Genco received net proceeds of $247 million, which were used to repay short-term debt, and for general corporate purposes.

In November 2010, Genco s $200 million 8.35% senior notes matured and were retired.

Indenture Provisions and Other Covenants

UE s and AIC s indenture provisions and articles of incorporation include covenants and provisions related to issuances of first mortgage bonds and preferred stock. UE and AIC are required to meet certain ratios to issue additional first mortgage bonds and preferred stock. However, not meeting these ratios would not result in a default under these covenants and provisions. The following table includes the required and actual earnings coverage ratios for interest charges and preferred dividends and bonds and preferred stock issuable for the 12 months ended December 31, 2010, at an assumed interest rate of 7% and dividend rate of 8%.

	Required Interest Coverage Ratio[a]	Actual Interest Coverage Ratio	Bonds Issuable[b]	Required Dividend Coverage Ratio[c]	Actual Dividend Coverage Ratio	Preferred Stock Issuable
UE	³2.0	3.6	$ 2,408	³2.5	78.2	$ 1,785
AIC	³2.0	6.8	3,184[d]	³1.5	3.4	203

(a) Coverage required on the annual interest charges on first mortgage bonds outstanding and to be issued. Coverage is not required in certain cases when additional first mortgage bonds are issued on the basis of retired bonds.
(b) Amount of bonds issuable based either on required coverage ratios or unfunded property additions, whichever is more restrictive. The amounts shown also include bonds issuable based on retired bond capacity of $91 million and $615 million at UE and AIC, respectively.
(c) Coverage required on the annual dividend on preferred stock outstanding and to be issued, as required in the respective company s articles of incorporation.
(d) Amount of bonds issuable by AIC based on unfunded property additions and retired bonds solely under the former IP mortgage indenture.

Ameren s indenture, pursuant to which Ameren s 8.875% $425 million senior unsecured notes due 2014 were issued, does not require Ameren to comply with any

quantitative financial covenants. The indenture does, however, include certain cross-default provisions. Specifically, either (1) the failure by Ameren to pay when

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due and upon expiration of any applicable grace period any portion of any Ameren indebtedness in excess of $25 million or (2) the acceleration upon default of the maturity of any Ameren indebtedness in excess of $25 million under any indebtedness agreement, including the 2010 Credit Agreements, constitutes a default under the indenture, unless such past due or accelerated debt is discharged or the acceleration is rescinded or annulled within a specified period.

UE, AIC and Genco as well as certain other nonregistrant Ameren subsidiaries are subject to Section 305(a) of the Federal Power Act, which makes it unlawful for any officer or director of a public utility, as defined in the Federal Power Act, to participate in the making or paying of any dividend from any funds properly included in capital account. The meaning of this limitation has never been clarified under the Federal Power Act or FERC regulations. However, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividends are not excessive, and (3) there is no self-dealing on the part of corporate officials. At a minimum, Ameren believes that dividends can be paid by its subsidiaries that are public utilities from net income and retained earnings. In addition, under Illinois law, AIC may not pay any dividend on their respective stock, unless, among other things, their respective earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless AIC has specific authorization from the ICC.

UE s mortgage indenture contains certain provisions that 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 dividends payable in common stock, which left $2 billion of free and unrestricted retained earnings at December 31, 2010.

AIC s articles of incorporation require its dividend payments on common stock to be based on ratios of common stock to total capitalization and other provisions related to certain operating expenses and accumulations of

earned surplus. AIC committed to FERC to maintain a minimum 30% equity capital structure following the AIC Merger and AERG distribution. See Note 16 Corporate Reorganization and Discontinued Operations for additional information.

Genco s indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make certain principal or interest payments, to make certain loans to or investments in affiliates, or to incur additional indebtedness. The following table summarizes these ratios for the 12 months ended and as of December 31, 2010:

	Required Interest Coverage Ratio	Actual Interest Coverage Ratio	Required Debt-to-Capital Ratio	Actual Debt-to-Capital Ratio
Genco[(a)]	≥1.75	4.00	≤60%	47%

(a) A minimum interest coverage ratio of 1.75 is required for Genco to make certain restricted payments, as defined, including specified dividend, principal and interest payments on certain subordinated intercompany borrowings. As of the date of the restricted payment, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods. The debt-to-capital ratio relates to a debt incurrence covenant, which also requires a minimum interest coverage ratio of 2.5 for the most recently ended four fiscal quarters.

Genco s debt incurrence-related ratio restrictions under its indenture may be disregarded if both Moody s and S&P reaffirm the ratings of Genco in place at the time of the debt incurrence after considering the additional indebtedness.

In order for the Ameren Companies to issue securities in the future, they will have to comply with all applicable tests in effect at the time of any such issuances.

Off-Balance-Sheet Arrangements

At December 31, 2010, none of the Ameren Companies had any off-balance-sheet financing arrangements, other than operating leases entered into in the ordinary course of business. None of the Ameren Companies expect to engage in any significant off-balance-sheet financing arrangements in the near future.

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NOTE 6 OTHER INCOME AND EXPENSES

The following table presents Other Income and Expenses for each of the Ameren Companies for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Ameren:[(a)]			
Miscellaneous income:			
Interest and dividend income	**$ 5**	$ 2	$ 15
Interest income on industrial development revenue bonds	**28**	28	28
Allowance for equity funds used during construction	**52**	36	28
Other	**5**	5	9
Total miscellaneous income	**$ 90**	$ 71	$ 80
Miscellaneous expense:			
Donations	**$ 19**	$ 12	$ 13
Other	**14**	11	18
Total miscellaneous expense	**$ 33**	$ 23	$ 31
UE:			
Miscellaneous income:			
Interest and dividend income	**$ 3**	$ 1	$ 5
Interest income on industrial development revenue bonds	**28**	28	28
Allowance for equity funds used during construction	**50**	33	28
Other	**2**	1	1
Total miscellaneous income	**$ 83**	$ 63	$ 62
Miscellaneous expense:			
Donations	**$ 8**	$ 3	$ 3
Other	**5**	4	6
Total miscellaneous expense	**$ 13**	$ 7	$ 9
AIC:			
Miscellaneous income:			
Interest and dividend income	**$ 1**	$ 6	$ 14
Allowance for equity funds used during construction	**2**	2	-
Other	**4**	4	9
Total miscellaneous income	**$ 7**	$ 12	$ 23
Miscellaneous expense:			
Donations	**$ 5**	$ 4	$ 7
Other	**8**	6	5
Total miscellaneous expense	**$ 13**	$ 10	$ 12
Genco:			
Miscellaneous income:			
Interest and dividend income	**$ -**	$ -	$ 1
Other	**1**	1	-
Total miscellaneous income	**$ 1**	$ 1	$ 1
Miscellaneous expense:			
Other	**$ 1**	$ 1	$ 1
Total miscellaneous expense	**$ 1**	$ 1	$ 1

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

NOTE 7 DERIVATIVE FINANCIAL INSTRUMENTS

We use derivatives principally to manage the risk of changes in market prices for natural gas, coal, diesel, electricity, uranium, and emission allowances. Such price fluctuations may cause the following:

- an unrealized appreciation or depreciation of our contracted commitments to purchase or sell when purchase or sale prices under the commitments are compared with current commodity prices;
- market values of coal, natural gas, and uranium inventories or emission allowances that differ from the cost of those commodities in inventory; and
- actual cash outlays for the purchase of these commodities that differ from anticipated cash outlays.

The derivatives that we use to hedge these risks are governed by our risk management policies for forward contracts, futures, options, and swaps. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting

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transactions are required. The goal of the hedging program is generally to mitigate financial risks while ensuring that sufficient volumes are available to meet our requirements.

Contracts we enter into as part of our risk management program may be settled financially, settled by physical delivery, or net settled with the counterparty.

The following table presents open gross derivative volumes by commodity type as of December 31, 2010, and 2009:

	Quantity (in millions, except as indicated)							
Commodity	NPNS Contracts[(a)]		Cash Flow Hedges[(b)]		Other Derivatives[(c)]		Derivatives That Qualify for Regulatory Deferral[(d)]	
	2010	2009	2010	2009	2010	2009	2010	2009
Coal (in tons)								
Ameren[(e)]	**73**	77	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
UE	**46**	43	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Genco	**21**	26	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Heating oil (in gallons)								
Ameren[(e)]	**(f)**	(f)	**(f)**	(f)	**55**	94	**80**	117
UE	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**80**	117
Genco	**(f)**	(f)	**(f)**	(f)	**43**	73	**(f)**	(f)
Natural gas (in mmbtu)								
Ameren[(e)]	**98**	165	**(f)**	(f)	**21**	28	**194**	136
UE	**13**	22	**(f)**	(f)	**2**	5	**21**	21
AIC	**85**	143	**(f)**	(f)	**(f)**	(f)	**173**	115
Genco	**(f)**	(f)	**(f)**	(f)	**3**	7	**(f)**	(f)
Power (in megawatthours)								
Ameren[(e)]	**63**	76	**2**	32	**61**	22	**18**	10
UE	**2**	4	**(f)**	(f)	**1**	1	**5**	4
AIC	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**26**	32
Genco	**(f)**	(f)	**(f)**	(f)	**3**	3	**(f)**	(f)
Uranium (pounds in thousands)								
Ameren	**5,810**	5,657	**(f)**	(f)	**(f)**	(f)	**185**	250
UE	**5,810**	5,657	**(f)**	(f)	**(f)**	(f)	**185**	250

(a) Contracts through December 2014, March 2015, September 2035, and October 2024 for coal, natural gas, power, and uranium, respectively, as of December 31, 2010.
(b) Contracts through May 2014 for power as of December 31, 2010.
(c) Contracts through December 2013, April 2012, and March 2014 for heating oil, natural gas, and power, respectively, as of December 31, 2010.
(d) Contracts through December 2013, March 2016, May 2013 and November 2011 for heating oil, natural gas, power, and uranium, respectively, as of December 31, 2010.
(e) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(f) Not applicable.

Authoritative accounting guidance regarding derivative instruments requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair values, unless the NPNS exception applies. See Note 8 Fair Value Measurements for discussion of our methods of assessing the fair value of derivative instruments. Many of our physical contracts, such as our coal and purchased power contracts, qualify for the NPNS exception to derivative accounting rules. The revenue or expense recorded in connection with NPNS contracts is recognized at the contract price upon physical delivery.

If we determine that a contract meets the definition of a derivative and is not eligible for the NPNS exception, we review the contract to determine if it qualifies for hedge accounting treatment. We also consider whether gains or losses resulting from such derivatives qualify for regulatory deferral. Contracts that qualify for cash flow hedge accounting treatment are recorded at fair value with changes in fair value charged or credited to accumulated OCI in the period in which the change occurs, to the extent

the hedge is effective. To the extent the hedge is ineffective, the related changes in fair value are charged or credited to the statement of income in the period in which the change occurs. When the contract is settled or delivered, the net gain or loss is recorded in the statement of income.

Derivative contracts that qualify for regulatory deferral are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs. Regulatory assets or regulatory liabilities are amortized to the statement of income as related losses and gains are reflected in rates charged to customers.

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for the NPNS exception, hedge accounting, or regulatory deferral accounting. Such contracts are recorded at fair value, with changes in fair value charged or credited to the statement of income in the period in which the change occurs.

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Authoritative accounting guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with

the same counterparty under the same master netting arrangement. The Ameren Companies did not elect to adopt this guidance for any eligible financial instruments or other items.

The following table presents the carrying value and balance sheet location of all derivative instruments as of December 31, 2010, and 2009:

	Balance Sheet Location	Ameren[(a)]	UE	AIC	Genco
2010:					
Derivative assets designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative assets	**$ 3**	**$ (b)**	**$ (b)**	**$ -**
	Other assets	**2**	**-**	**-**	**-**
	Total assets	**$ 5**	**$ -**	**$ -**	**$ -**
Derivative liabilities designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative liabilities	**$ 1**	**$ (b)**	**$ -**	**$ -**
	Total liabilities	**$ 1**	**$ -**	**$ -**	**$ -**
Derivative assets not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative assets	**$ 42**	**$ (b)**	**$ (b)**	**$ 14**
	Other current assets	**-**	**24**	**-**	**-**
	Other assets	**22**	**13**	**-**	**7**
Natural gas	MTM derivative assets	**4**	**(b)**	**(b)**	**1**
	Other current assets	**-**	**1**	**1**	**-**
	Other assets	**1**	**-**	**1**	**-**
Power	MTM derivative assets	**78**	**(b)**	**(b)**	**11**
	Other current assets	**-**	**8**	**2**	**-**
	Other assets	**20**	**-**	**6**	**-**
Uranium	MTM derivative assets	**2**	**(b)**	**(b)**	**-**
	Other current assets	**-**	**2**	**-**	**-**
	Total assets	**$ 169**	**$ 48**	**$ 10**	**$ 33**
Derivative liabilities not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative liabilities	**$ 12**	**$ (b)**	**$ -**	**$ 4**
	Other current liabilities	**-**	**7**	**-**	**-**
	Other deferred credits and liabilities	**1**	**-**	**-**	**-**
Natural gas	MTM derivative liabilities	**87**	**(b)**	**73**	**2**
	Other current liabilities	**-**	**11**	**-**	**-**
	Other deferred credits and liabilities	**84**	**13**	**70**	**-**
Power	MTM derivative liabilities	**61**	**(b)**	**9**	**3**
	MTM derivative liabilities - affiliates	**(b)**	**(b)**	**172**	**5**
	Other current liabilities	**-**	**6**	**-**	**-**
	Other deferred credits and liabilities	**7**	**-**	**179**	**-**
	Total liabilities	**$ 252**	**$ 37**	**$ 503**	**$ 14**
2009:					
Derivative assets designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative assets	$ 20	$ (b)	$ (b)	$ -
	Other assets	4	-	-	-
	Total assets	$ 24	$ -	$ -	$ -
Derivative liabilities designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative liabilities	$ 1	$ (b)	$ -	$ -
	Total liabilities	$ 1	$ -	$ -	$ -

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	Balance Sheet Location	Ameren[a]	UE	AIC	Genco
Derivative assets not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative assets	$ 39	$ (b)	$ (b)	$ 14
	Other current assets	-	22	-	-
	Other assets	41	23	-	14
Natural gas	MTM derivative assets	19	(b)	(b)	-
	Other current assets	-	2	3	-
	Other assets	4	-	3	-
Power	MTM derivative assets	43	(b)	(b)	8
	Other current assets	-	7	-	-
	Other assets	10	-	-	-
	Total assets	$ 156	$ 54	$ 6	$ 36
Derivative liabilities not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative liabilities	$ 15	$ (b)	$ -	$ 5
	Other current liabilities	-	9	-	-
	Other deferred credits and liabilities	5	3	-	2
Natural gas	MTM derivative liabilities	55	(b)	32	1
	Other current liabilities	-	10	-	-
	Other deferred credits and liabilities	44	6	36	-
Power	MTM derivative liabilities	37	(b)	6	6
	MTM derivative liabilities - affiliates	(b)	(b)	127	1
	Other current liabilities	-	8	-	-
	Other deferred credits and liabilities	4	-	289	-
Uranium	MTM derivative liabilities	1	(b)	-	-
	Other current liabilities	-	1	-	-
	Other deferred credits and liabilities	1	1	-	-
	Total liabilities	$ 162	$ 38	$ 490	$ 15

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Balance sheet line item not applicable to registrant.

The following table presents the cumulative amount of pretax net gains (losses) on all derivative instruments in accumulated OCI and regulatory assets or regulatory liabilities as of December 31, 2010, and 2009:

	Ameren[a]	UE	AIC	Genco
2010:				
Cumulative gains (losses) deferred in accumulated OCI:				
Power derivative contracts[b]	**$ 8**	**$ -**	**$ -**	**$ -**
Interest rate derivative contracts[c][d]	**(9)**	**-**	**-**	**(9)**
Cumulative gains (losses) deferred in regulatory liabilities or assets:				
Heating oil derivative contracts[e]	**19**	**19**	**-**	**-**
Natural gas derivative contracts[f]	**(165)**	**(24)**	**(141)**	**-**
Power derivative contracts[g]	**1**	**3**	**(352)**	**-**
Uranium derivative contracts[h]	**2**	**2**	-	-
2009:				
Cumulative gains (losses) deferred in accumulated OCI:				
Power derivative contracts[b]	$ 24	$ -	$ -	$ -
Interest rate derivative contracts[c][d]	(10)	-	-	(10)
Cumulative gains (losses) deferred in regulatory liabilities or assets:				
Heating oil derivative contracts[e]	5	5	-	-
Natural gas derivative contracts[f]	(74)	(13)	(61)	-
Power derivative contracts[g]	(11)	(1)	(422)	-
Uranium derivative contracts[h]	(2)	(2)	-	-

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Represents net gains associated with power derivative contracts at Ameren. These contracts are a partial hedge of electricity price exposure through May 2014 as of December 31, 2010. Current gains of $8 million and $22 million were recorded at Ameren as of December 31, 2010, and December 31, 2009,

respectively.

(c) Includes net gains 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 10 years of debt that has a 30-year maturity, and the gain in OCI is amortized over a 10-year period that began in June 2002. The carrying value at December 31, 2010, and December 31, 2009, was less than $1 million and $1 million, respectively. The balance of the gain will be amortized by June 2012.

(d) Includes net losses associated with interest rate swaps at Genco. The swaps were executed during the fourth quarter of 2007 as a partial hedge of interest rate risks associated with Genco s April 2008 debt issuance. The loss on the interest rate swaps is being amortized over a 10-year period that began in April 2008. The carrying value at December 31, 2010, and December 31, 2009, was a loss of $10 million and a loss of $11 million, respectively. Over the next 12 months, $1.4 million of the loss will be amortized.

(e) Represents net gains on heating oil derivative contracts at UE. These contracts are a partial hedge of UE s transportation costs for coal through December 2013 as of December 31, 2010. Current gains deferred as regulatory liabilities include $13 million at UE as of December 31, 2010. Current losses deferred as regulatory assets include $6 million at UE as of December 31, 2010. Current gains deferred as regulatory liabilities include $5 million at UE as of December 31, 2009. Current losses deferred as regulatory assets include $9 million at UE as of December 31, 2009.

(f) Represents net losses associated with natural gas derivative contracts. These contracts are a partial hedge of natural gas requirements through March 2016 at Ameren and AIC and through October 2015 at UE, in each case as of December 31, 2010. Current gains deferred as regulatory liabilities include $1 million and $1 million at Ameren and UE, respectively, as of December 31, 2010. Current losses deferred as regulatory assets include $84 million, $11 million, and $73 million at Ameren, UE and AIC, respectively, as of December 31, 2010. Current gains deferred as regulatory liabilities include $4 million, $1 million, and $3 million at Ameren, UE and AIC, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $40 million, $8 million, and $32 million at Ameren, UE and AIC, respectively, as of December 31, 2009.

(g) Represents net losses associated with power derivative contracts. These contracts are a partial hedge of power price requirements through May 2013 at Ameren and AIC and through December 2012 at UE, in each case as of December 31, 2010. Current gains deferred as regulatory liabilities include $8 million, $6 million, and $2 million at Ameren, UE and AIC, respectively, as of December 31, 2010. Current losses deferred as regulatory assets include $13 million, $3 million, and $181 million at Ameren, UE and AIC, respectively, as of December 31, 2010. Current gains deferred as regulatory liabilities include $5 million and $5 million at Ameren and UE, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $12 million, $6 million, and $133 million at Ameren, UE and AIC, respectively, as of December 31, 2009.

(h) Represents net losses on uranium derivative contracts at UE. These contracts are a partial hedge of our uranium requirements through November 2011 as of December 31, 2010. Current gains deferred as regulatory liabilities include $2 million at UE as of December 31, 2010. Current losses deferred as regulatory assets include $1 million at UE as of December 31, 2009.

Derivative instruments are subject to various credit-related losses in the event of nonperformance by counterparties to the transaction. Exchange-traded contracts are supported by the financial and credit quality of the clearing members of the respective exchanges and have nominal credit risk. In all other transactions, we are exposed to credit risk. Our credit risk management program involves establishing credit limits and collateral requirements for counterparties, using master trading and netting agreements, and reporting daily exposure to senior management.

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from default by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association Agreement, a standardized financial natural gas and electric contract; (2) the Master Power Purchase and Sale Agreement, created by the Edison Electric Institute and the National Energy Marketers Association, a standardized contract for the purchase and sale of wholesale power; and (3) the North American Energy Standards Board Inc. agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Further, collateral requirements are calculated at a master trading and netting agreement level by counterparty.

Concentrations of Credit Risk

In determining our concentrations of credit risk related to derivative instruments, we review our individual counterparties and categorize each counterparty into one of eight groupings according to the primary business in which each engages. The following table presents the maximum exposure, as of December 31, 2010, and 2009, if counterparty groups were to completely fail to perform on contracts by grouping. The maximum exposure is based on the gross fair value of financial instruments, including NPNS contracts, which excludes collateral held, and does not consider the legally binding right to net transactions based on master trading and netting agreements.

	Affiliates[a]	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren[b]	**$ 410**	**$ 30**	**$ 16**	**$ 22**	**$ 72**	**$ 550**	**$ 10**	**$ 72**	**$ 1,182**
UE	**-**	**21**	**1**	**2**	**5**	**11**	**1**	**-**	**41**
AIC	**-**	**-**	**3**	**-**	**1**	**-**	**-**	**-**	**4**
Genco	**-**	**6**	**2**	**1**	**1**	**-**	**6**	**-**	**16**
2009:									
Ameren[b]	$ 517	$ 9	$ 16	$ 23	$ 123	$ 165	$ 11	$ 63	$ 927
UE	-	5	2	7	30	22	-	-	66

AIC	-	-	-	-	6	-	1	-	7
Genco	-	2	1	2	3	-	6	-	14

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(a) Primarily comprised of Marketing Company s exposure to AIC related to financial contracts. The exposure is not eliminated at the consolidated Ameren level for purposes of this disclosure, as it is calculated without regard to the offsetting affiliate counterparty s liability position. See Note 14 Related Party Transactions in the Form 10-K for additional information on these financial contracts.

(b) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

The following table presents the amount of cash collateral held from counterparties, as of December 31, 2010, and 2009, based on the contractual rights under the agreements to seek collateral and the maximum exposure as calculated under the individual master trading and netting agreements:

	Affiliates	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren[a]	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1**	**$ 1**
2009:									
Ameren[a]	$ -	$ -	$ 3	$ -	$ 7	$ -	$ -	$ -	$ 10

(a) Represents amounts held by Marketing Company used to reduced exposure. As of December 31, 2010, and 2009. Ameren registrant subsidiaries held no cash collateral used to reduce the exposure after consideration of master trading and netting agreements.

The potential loss on counterparty exposures is reduced by the application of master trading and netting agreements and collateral held to the extent of reducing the exposure to zero. Collateral includes both cash collateral and other collateral held. As of December 31, 2010, other collateral used to reduce exposure consisted of letters of credit in the amount of $28 million and $1 million held by Ameren and AIC, respectively. As of December 31, 2009, other collateral used to reduce exposure consisted of letters of credit in the amount of $32 million, $1 million, and $1 million held by Ameren, UE and Genco, respectively. The following table presents the potential loss after consideration of the application of master trading and netting agreements and collateral held as of December 31, 2010, and 2009:

	Affiliates[a]	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren[b]	**$ 404**	**$ 10**	**$ 11**	**$ 9**	**$ 59**	**$ 523**	**$ 7**	**$ 71**	**$ 1,094**
UE	**-**	**8**	**-**	**1**	**2**	**10**	**-**	**-**	**21**
AIC	**-**	**-**	**2**	**-**	**-**	**-**	**-**	**-**	**2**
Genco	**-**	**1**	**1**	**1**	**1**	**-**	**5**	**-**	**9**
2009:									
Ameren[b]	$ 515	$ -	$ 3	$ 11	$ 93	$ 132	$ 10	$ 61	$ 825
UE	-	-	1	5	26	21	-	-	53
AIC	-	-	-	-	1	-	1	-	2
Genco	-	-	-	2	-	-	5	-	7

(a) Primarily made up of Marketing Company s exposure to AIC related to financial contracts. The exposure is not eliminated at the consolidated Ameren level for purposes of this disclosure, as it is calculated without regard to the offsetting affiliate counterparty s liability position. See Note 14 Related Party Transactions in the Form 10-K for additional information on these financial contracts.

(b) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

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Derivative Instruments with Credit Risk-Related Contingent Features

Our commodity contracts contain collateral provisions tied to the Ameren Companies credit ratings. If we were to experience an adverse change in our credit ratings, or if a counterparty with reasonable grounds for uncertainty regarding performance of an obligation requested adequate assurance of performance, additional collateral postings might be required. The following table presents, as of December 31, 2010, and 2009, the aggregate fair value of all derivative instruments with credit risk-related contingent features in a gross liability position, the cash collateral posted, and the aggregate amount of additional collateral that could be required to be posted with counterparties. The additional collateral required is the net liability position allowed under the master trading and netting agreements assuming (1) the credit risk-related contingent features underlying these agreements were triggered on December 31, 2010 or 2009, respectively, and (2) those counterparties with rights to do so requested collateral:

	Aggregate Fair Value of Derivative Liabilities[a]	Cash Collateral Posted	Potential Aggregate Amount of Additional Collateral Required[b]
2010:			
Ameren[c]	**$ 431**	**$ 134**	**$ 274**
UE	**105**	**7**	**93**
AIC	**233**	**109**	**111**
Genco	**31**	**-**	**28**
2009:			
Ameren[c]	$ 500	$ 61	$ 367
UE	151	8	129
AIC	148	14	107
Genco	60	-	48

(a) Prior to consideration of master trading and netting agreements and including NPNS contract exposures.
(b) As collateral requirements with certain counterparties are based on master trading and netting agreements, the aggregate amount of additional collateral required to be posted is after consideration of the effects of such agreements.
(c) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

Cash Flow Hedges

The following table presents the pretax net gain or loss for the year ended December 31, 2010, and 2009, associated with derivative instruments designated as cash flow hedges:

Derivatives in Cash Flow Hedging Relationship	Gain (Loss) Recognized in OCI on Derivatives[a]	Location of (Gain) Loss Reclassified from Accumulated OCI into Income[b]	(Gain) Loss Reclassified from Accumulated OCI into Income[b]	Location of Gain (Loss) Recognized in Income on Derivatives[c]	Gain (Loss) Recognized in Income on Derivatives[c]
2010:					
Ameren:[d]					
Power	**$ (2)**	Operating Revenues - Electric	**$ (14)**	Operating Revenues - Electric	**$ (3)**
Interest rate[e]	**-**	Interest Charges	**(f)**	Interest Charges	-
Genco:					
Interest rate[e]	-	Interest Charges	**(f)**	Interest Charges	-
2009:					
Ameren:[d]					
Power	$ 41	Operating Revenues - Electric	$ (101)	Operating Revenues - Electric	$ (16)
Interest rate[e]	-	Interest Charges	(f)	Interest Charges	-

UE:					
Power	(21)	Operating Revenues - Electric	(19)	Operating Revenues - Electric	2
Genco:					
Interest rate[(e)]	-	Interest Charges	(f)	Interest Charges	-

(a) Effective portion of gain (loss).
(b) Effective portion of (gain) loss on settlements.
(c) Ineffective portion of gain (loss) and amount excluded from effectiveness testing.
(d) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(e) Represents interest rate swaps settled in prior periods. The cumulative gain and loss on the interest rate swaps is being amortized into income over a 10-year period.
(f) Less than $1 million.

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Other Derivatives

The following table represents the net change in market value associated with derivatives not designated as hedging instruments for the years ended December 31, 2010, and 2009:

	Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives		Gain (Loss) Recognized in Income on Derivatives 2010	2009
Ameren[(a)]	Heating oil	Operating Expenses - Fuel		**$ 9**	$ 52
	Natural gas (generation)	Operating Expenses - Fuel		**-**	5
	Natural gas (resale)	Operating Revenues - Gas		**-**	6
	Power	Operating Revenues - Electric		**9**	(25)
	SO_2 emission allowances	Operating Expenses - Fuel		**-**	1
			Total	**$ 18**	$ 39
UE	Heating oil	Operating Expenses - Fuel		**$ -**	$ 25
	Natural gas (generation)	Operating Expenses - Fuel		**1**	2
			Total	**$ 1**	$ 27
AIC	Natural gas (resale)	Operating Revenues - Gas		**$ -**	$ 6
Genco	Heating oil	Operating Expenses - Fuel		**$ 7**	$ 25
	Natural gas (generation)	Operating Expenses - Fuel		**-**	(1)
	Power	Operating Revenues		**1**	2
	SO_2 emission allowances	Operating Expenses - Fuel		**-**	1
			Total	**$ 8**	$ 27

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

Derivatives Subject to Regulatory Deferral

The following table represents the net change in market value associated with derivatives that qualify for regulatory deferral for the years ended December 31, 2010, and 2009:

	Derivatives that Qualify for Regulatory Deferral		Net Change in Market Value 2010	2009
Ameren[(a)]	Heating oil		**$ 14**	$ 5
	Natural gas		**(91)**	41
	Power		**12**	(8)
	Uranium		**4**	(2)
		Total	**$ (61)**	$ 36
UE	Heating oil		**$ 14**	$ 5
	Natural gas		**(11)**	3
	Power		**4**	(1)
	Uranium		**4**	(2)
		Total	**$ 11**	$ 5
AIC	Natural gas		**$ (80)**	$ 38
	Power		**70**	(249)
		Total	**$ (10)**	$ (211)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

UE and AIC believe derivative gains and losses deferred as regulatory assets and regulatory liabilities are probable of recovery or refund through future rates charged to customers. Regulatory assets and regulatory liabilities are amortized to operating expenses as related losses and gains are reflected in revenue through rates charged to customers. Therefore, gains and losses on these derivatives have no effect on operating income.

As part of the 2007 Illinois Electric Settlement Agreement and the Illinois RFP power procurement processes, AIC entered into financial contracts with Marketing Company. These financial contracts are derivative instruments. They are accounted for as cash flow hedges by Marketing Company and as derivatives that qualify for regulatory deferral by AIC. Consequently, AIC and Marketing Company record the fair value of the contracts on their respective balance sheets and the changes to the fair value in regulatory assets or liabilities by AIC and OCI by Marketing Company. In Ameren s consolidated financial statements, all financial statement effects of the derivative instruments entered into among affiliates were eliminated. See Note 14 Related Party Transactions under Part II, Item 8 of this report for additional information on these financial contracts. The following table presents the fair value of the swaps included on AIC s balance sheet at December 31, 2010, and 2009:

			2010	2009
AIC	MTM derivative liabilities - affiliates		**$ 172**	$ 127
	Other deferred credits and liabilities		**178**	286
		Total	**$ 350**	$ 413

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NOTE 8 FAIR VALUE MEASUREMENTS

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. We use various methods to determine fair value, including market, income, and cost approaches. With these approaches, we adopt certain assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk or the risks inherent in the inputs to the valuation. Inputs to valuation can be readily observable, market-corroborated, or unobservable. We use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Authoritative accounting guidance established a fair value hierarchy that prioritizes the inputs used to measure fair value. All financial assets and liabilities carried at fair value are classified and disclosed in one of the following three hierarchy levels:

Level 1: Inputs based on quoted prices in active markets for identical assets or liabilities. Level 1 assets and liabilities are primarily exchange-traded derivatives and assets, including U.S. treasury securities and listed equity securities, such as those held in UE s Nuclear Decommissioning Trust Fund.

Level 2: Market-based inputs corroborated by third-party brokers or exchanges based on transacted market data. Level 2 assets and liabilities include certain assets held in UE s Nuclear Decommissioning Trust Fund, including corporate bonds and other fixed-income securities, and certain over-the-counter derivative instruments, including natural gas swaps and financial power transactions. Derivative instruments classified as Level 2 are valued using corroborated observable inputs, such as pricing services or prices from similar instruments that trade in liquid markets. Our development and corroboration process entails obtaining multiple quotes or prices from outside sources. To derive our forward view to price our derivative instruments at fair value, we average the midpoints of the bid/ask spreads. To validate forward prices obtained from outside parties, we compare the pricing to recently settled market transactions. Additionally, a review of all sources is performed to identify any anomalies or potential errors. Further, we consider the volume of transactions on certain trading platforms in our reasonableness assessment of the averaged midpoint.

Level 3: Unobservable inputs that are not corroborated by market data. Level 3 assets and liabilities are valued based on internally developed models and assumptions or methodologies that use significant unobservable inputs. Level 3 assets and liabilities include derivative instruments that trade in less liquid markets, where pricing is largely unobservable, including the financial contracts entered into between the AIC and Marketing Company. We value Level 3 instruments by using pricing models with inputs that are often unobservable in the market, as well as certain internal assumptions. Our development and corroboration process entails obtaining multiple quotes or prices from outside

sources. As a part of our reasonableness review, an evaluation of all sources is performed to identify any anomalies or potential errors.

We perform an analysis each quarter to determine the appropriate hierarchy level of the assets and liabilities subject to fair value measurements. Financial assets and liabilities are classified in their entirety according to the lowest level of input that is significant to the fair value measurement. All assets and liabilities whose fair value measurement is based on significant unobservable inputs are classified as Level 3.

In accordance with applicable authoritative accounting guidance, we consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The guidance also requires that the fair value measurement of liabilities reflect the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Included in our valuation, and based on current market conditions, is a valuation adjustment for counterparty default derived from market data such as the price of credit default swaps, bond yields, and credit ratings. Ameren recorded net gains of less than $1 million, net losses of less than $1 million, and net losses of $5 million in 2010, 2009 and 2008, respectively, related to valuation adjustments for counterparty default risk. Genco recorded net gains of less than $1 million and less than $1 million in 2010 and 2009, respectively, and recorded no net gains in 2008, related to valuation adjustments for counterparty default risk. At December 31, 2010, the counterparty default risk valuation adjustment related to derivative contracts totaled $2 million, less than $1 million, $21 million, and less than $1 million for Ameren, UE, AIC and Genco, respectively. At December 31, 2009, the counterparty default risk valuation adjustment related to derivative contracts totaled $3 million, less than $1 million, $24 million, and less than $1 million for Ameren, UE, AIC and Genco, respectively.

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The following table sets forth, by level within the fair value hierarchy, our assets and liabilities measured at fair value on a recurring basis as of December 31, 2010:

		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[a]	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 64	$ 64
	Natural gas	3	-	2	5
	Power	-	17	86	103
	Uranium	-	-	2	2
	Nuclear Decommissioning Trust Fund[c]:				
	Cash and cash equivalents	1	-	-	1
	Equity securities:				
	U.S. large capitalization	228	-	-	228
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	2	-	2
	U.S. treasury and agency securities	-	50	-	50
	Asset-backed securities	-	14	-	14
	Other	-	1	-	1
UE	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	37	37
	Natural gas	-	-	1	1
	Power	-	3	5	8
	Uranium	-	-	2	2
	Nuclear Decommissioning Trust Fund[c]:				
	Cash and cash equivalents	1	-	-	1
	Equity securities:				
	U.S. large capitalization	228	-	-	228
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	2	-	2
	U.S. treasury and agency securities	-	50	-	50
	Asset-backed securities	-	14	-	14
	Other	-	1	-	1
AIC	Derivative assets - commodity contracts[b]:				
	Natural gas	-	-	2	2
	Power	-	-	8	8
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	21	21
	Natural gas	1	-	-	1
	Power	-	-	11	11
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 13	$ 13
	Natural gas	21	-	150	171
	Power	-	19	50	69
UE	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	7	7
	Natural gas	9	-	15	24
	Power	-	3	3	6
AIC	Derivative liabilities - commodity contracts[b]:				
	Natural gas	7	-	136	143

	Power	-	-	360	360
Genco	Derivative liabilities - commodity contracts(b):				
	Heating oil	-	-	4	4
	Natural gas	2	-	-	2
	Power	-	-	8	8

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The derivative asset and liability balances are presented net of counterparty credit considerations.
(c) Balance excludes $1 million of receivables, payables, and accrued income, net.

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The following table sets forth, by level within the fair value hierarchy, our assets and liabilities measured at fair value on a recurring basis as of December 31, 2009:

		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[a]	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 80	$ 80
	Natural gas	13	-	10	23
	Power	-	3	74	77
	Nuclear Decommissioning Trust Fund[c]:				
	Equity securities:				
	U.S. large capitalization	195	-	-	195
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	1	-	1
	U.S. treasury and agency securities[d]	-	49	-	49
	Asset-backed securities	-	5	-	5
	Other	-	2	-	2
UE	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	44	44
	Natural gas	1	-	2	3
	Power	-	2	5	7
	Nuclear Decommissioning Trust Fund[c]:				
	Equity securities:				
	U.S. large capitalization	195	-	-	195
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	1	-	1
	U.S. treasury and agency securities[d]	-	49	-	49
	Asset-backed securities	-	5	-	5
	Other	-	2	-	2
AIC	Derivative assets - commodity contracts[b]:				
	Natural gas	-	-	6	6
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	28	28
	Power	-	-	8	8
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 20	$ 20
	Natural gas	22	-	77	99
	Power	4	2	36	42
	Uranium	-	-	2	2
UE	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	12	12
	Natural gas	8	-	8	16
	Power	-	2	6	8
	Uranium	-	-	2	2
AIC	Derivative liabilities - commodity contracts[b]:				
	Natural gas	2	-	66	68
	Power	-	-	422	422
Genco	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	7	7
	Natural gas	1	-	-	1

Power	-	-	7	7

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The derivative asset and liability balances are presented net of counterparty credit considerations.
(c) Balance excludes $1 million of receivables, payables, and accrued income, net.
(d) For the year ended December 31, 2009, $37 million of previously classified Level 1 assets within the Nuclear Decommissioning Trust Fund were recategorized to Level 2.

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The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 31, 2010:

		Realized and Unrealized Gains (Losses)							
	Beginning Balance at January 1, 2010	Included in Earnings[a]	Included in OCI	Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Net Transfers into/out of Level 3	Ending Balance at December 31, 2010	Change in Unrealized Gains (Losses) Related to Assets/ Liabilities Still Held at December 31, 2010
Net derivative commodity contracts:									
Ameren:									
Heating oil	$ 60	$ 1	$ -	$ 8	$ 9	$ (18)	$ -	$ 51	$ 11
Natural gas	(67)	-	-	(172)	(172)	91	-	(148)	(92)
Power	38	34	8	15	57	(25)	(34)	36	(7)
Uranium	(2)	-	-	3	3	1	-	2	1
UE:									
Heating oil	32	-	-	9	9	(11)	-	30	7
Natural gas	(6)	-	-	(20)	(20)	12	-	(14)	(11)
Power	(1)	-	-	27	27	(18)	(6)	2	1
Uranium	(2)	-	-	3	3	1	-	2	1
AIC:									
Natural gas	(60)	-	-	(152)	(152)	78	-	(134)	(82)
Power	(422)	-	-	(107)	(107)	177	-	(352)	(89)
Genco:									
Heating oil	21	3	-	-	3	(7)	-	17	4
Natural gas	-	1	-	-	1	(1)	-	-	-
Power	1	3	-	-	3	(1)	-	3	-

(a) See Note 7 Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.

The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009:

		Realized and Unrealized Gains (Losses)							
	Beginning Balance at January 1, 2009	Included in Earnings[a]	Included in OCI	Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Net Transfers into/out of Level 3	Ending Balance at December 31, 2009	Change in Unrealized Gains (Losses) Related to Assets/ Liabilities Still Held at December 31, 2009
Other current assets:									
Ameren:									
Mutual fund	$ 6	$ -	$ -	$ -	$ -	$ -	$ (6)[b]	$ -	$ -
Net derivative commodity contracts:									

Ameren:									
Heating oil	$ 6	$ 21	$ -	$ 28	$ 49	$ 5	$ -	$ 60	$ 1
Natural gas	(122)	(21)	12	(93)	(102)	157	-	(67)	(18)
Power	134	75	71	(46)	100	(127)	(69)	38	37
SO_2	(1)	-	-	-	-	1	-	-	-
Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
UE:									
Heating oil	-	-	-	28	28	4	-	32	-
Natural gas	(20)	-	12	(23)	(11)	25	-	(6)	2
Power	27	-	20	7	27	(34)	(21)	(1)	3
Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
AIC:									
Natural gas	(103)	(20)	-	(70)	(90)	133	-	(60)	(20)
Power	(170)	-	-	(462)	(462)	210	-	(422)	(306)
Genco:									
Heating oil	-	7	-	-	7	14	-	21	-
Natural gas	-	(1)	-	-	(1)	1	-	-	-
Power	-	(1)	-	-	(1)	2	-	1	-
SO_2	(1)	-	-	-	-	1	-	-	-
Net derivative foreign currency contracts:									
Ameren	$ (2)	$ -	$ 5	$ (3)	$ 2	$ -	$ -	$ -	$ -
UE	(2)	-	5	(3)	2	-	-	-	-
Nuclear Decommissioning Trust Fund:									
Ameren:									
Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -
UE:									
Mutual fund	2	-	-	-	-	(2)	-	-	-

(a) See Note 7 Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.
(b) Represents transfer out of Level 3.

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Transfers in or out of Level 3 represent either (1) existing assets and liabilities that were previously categorized as a higher level but were recategorized to Level 3 because the inputs to the model became unobservable during the period, or (2) existing assets and liabilities that were previously classified as Level 3 but were recategorized to a higher level because the lowest significant input became observable during the period. Transfers between Level 2 and Level 3 were primarily caused by changes in availability of financial power trades observable on electronic exchanges from the previous reporting period for the years ended December 31, 2010, and 2009. Any reclassifications are reported as transfers out of Level 3 at the fair value measurement reported at the beginning of the period in which the changes occur. For the years ended December 31, 2010, and 2009, there were no transfers between Level 1 and Level 2 related to derivative commodity contracts. The following table summarizes all transfers between fair value hierarchy levels related to derivative commodity contracts for the years ended December 31, 2010, and 2009:

	2010	2009
Ameren derivative commodity contracts:[(a)]		
Transfers into Level 3 / Transfers out of Level 1	**$ (1)**	$ -
Transfers into Level 3 / Transfers out of Level 2	**(1)**	-
Transfers out of Level 3 / Transfers into Level 2	**(32)**	(69)
Net fair value of Level 3 transfers	**$ (34)**	$ (69)
UE derivative power commodity contracts:		
Transfers out of Level 3 / Transfers into Level 2	**$ (6)**	$ (21)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

See Note 11 Retirement Benefits for the fair value hierarchy tables detailing Ameren s pension and postretirement plan assets as of December 31, 2010, as well as a table summarizing the changes in Level 3 plan assets during 2010.

The Ameren Companies carrying amounts of cash and cash equivalents, accounts receivable, short-term borrowings, and accounts payable approximate fair value because of the short-term nature of these instruments. The estimated fair value of long-term debt and preferred stock is based on the quoted market prices for same or similar issues for companies with similar credit profiles or on the current rates offered to the Ameren Companies for similar financial instruments.

The following table presents the carrying amounts and estimated fair values of our long-term debt and preferred stock at December 31, 2010, and 2009:

	2010		2009	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Ameren:[(a)(b)]				
Long-term debt and capital lease obligations (including current portion)	**$ 7,008**	**$ 7,661**	$ 7,315	$ 7,717
Preferred stock	**142**	**102**	195	150
UE:				
Long-term debt and capital lease obligations (including current portion)	**$ 3,954**	**$ 4,281**	$ 4,022	$ 4,152
Preferred stock	**80**	**62**	113	95
AIC:				
Long-term debt (including current portion)	**$ 1,807**	**$ 2,067**	$ 1,847	$ 2,041
Preferred stock	**62**	**40**	115	82
Genco:				
Long-term debt (including current portion)	**$ 824**	**$ 826**	$ 1,023	$ 1,046

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Preferred stock along with the 20% noncontrolling interest of EEI is recorded in Noncontrolling Interests on the balance sheet.

NOTE 9 NUCLEAR DECOMMISSIONING TRUST FUND INVESTMENTS

UE has investments in debt and equity securities that are held in a trust fund for the purpose of funding the decommissioning of its Callaway nuclear plant. See Note 10 Callaway Nuclear Plant for additional information. We have classified these investments as available for sale, and we have recorded all such investments at their fair market value at December 31, 2010, and 2009.

Investments in the nuclear decommissioning trust fund have a target allocation of 60% to 70% in equity securities, with the balance invested in debt securities.

The following table presents proceeds from the sale of investments in UE s nuclear decommissioning trust fund and the gross realized gains and losses resulting from those sales for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Proceeds from sales	**$ 256**	$ 380	$ 497
Gross realized gains	**5**	5	5
Gross realized losses	**4**	10	8

Net realized and unrealized gains and losses are deferred and recorded as regulatory assets or regulatory liabilities on Ameren s and UE s balance sheets. This reporting is consistent with the method used to account for the decommissioning costs recovered in rates. Gains or losses associated with assets in the trust fund could result

in lower or higher funding requirements for decommissioning costs, which are expected to be reflected in electric rates paid by UE s customers. See Note 2 Rate and Regulatory Matters.

The following table presents the costs and fair values of investments in debt and equity securities in UE s nuclear decommissioning trust fund at December 31, 2010, and 2009:

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
2010:				
Debt securities	**$ 104**	**$ 4**	**$ 1**	**$ 107**
Equity securities	**141**	**95**	**8**	**228**
Cash	**1**	**-**	**-**	**1**
Other(b)	**1**	**-**	**-**	**1**
Total	**$ 247**	**$ 99**	**$ 9**	**$ 337**
2009:				
Debt securities	$ 95	$ 3	$ 1	$ 97
Equity securities	137	72	14	195
Cash	(a)	-	-	(a)
Other(b)	1	-	-	1
Total	$ 233	$ 75	$ 15	$ 293

(a) Amount less than $1 million.

(b) Represents payables relating to pending security purchases, net of receivables related to pending securities sales and interest receivables.

The following table presents the costs and fair values of investments in debt securities in UE s nuclear decommissioning trust fund according to their contractual maturities at December 31, 2010:

	Cost	Fair Value
Less than 5 years	$ 41	$ 42
5 years to 10 years	36	38
Due after 10 years	27	27
Total	$ 104	$ 107

We have unrealized losses relating to certain available-for-sale investments included in our decommissioning trust fund, recorded as regulatory assets as discussed above. Decommissioning will not occur until the operating license for our nuclear facility expires. UE intends to submit a license extension application to the NRC to extend the Callaway nuclear plant s operating license to 2044. The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in UE s nuclear decommissioning trust fund. They are aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position at December 31, 2010:

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
Debt securities	$ 37	$ 1	$ (a)	$ (a)	$ 37	$ 1
Equity securities	7	1	17	7	24	8
Total	$ 44	$ 2	$ 17	$ 7	$ 61	$ 9

(a) Amount less than $1 million.

NOTE 10 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 one-tenth of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel (the NWF fee). Pursuant to this act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates and sells from its Callaway nuclear plant. Electric utility rates charged to customers provide for recovery of

such costs. UE has sufficient installed storage capacity for spent nuclear fuel at its Callaway nuclear plant until 2020. It has the capability for additional storage capacity through the licensed life of the plant. In March 2010, the DOE submitted a motion to withdraw the Yucca Mountain Repository license application it filed with the NRC. In anticipation of this action, the Nuclear Energy Institute (NEI) in July 2009 formally requested that DOE promptly perform the statutorily required annual fee adequacy review and immediately suspend collection of the NWF fee. The Nuclear Waste Policy Act mandates that DOE compare the revenue generated by the NWF fee with the costs of the waste disposal program and adjust the size of the NWF fee to match the cost of the program. In the past, the cost of the program reviewed by DOE for NWF fee adequacy has been the cost of constructing and operating the Yucca Mountain Repository. The DOE declined to eliminate or reduce the NWF fee. As a result, NEI and the National Association of Regulatory Utility Commissioners filed petitions for review in the United States Court of Appeals for the District of Columbia Circuit seeking suspension of the NWF fee due to the DOE s motion to withdraw the application. These lawsuits were consolidated, and in December 2010 the court dismissed the petitions for review as moot (with respect to asking DOE to conduct the annual fee adequacy review) and rejected the request to suspend the fee. The DOE has established the Blue Ribbon Commission on America s Nuclear Future to conduct a comprehensive review of policies for managing certain components of the nuclear fuel cycle, including all alternatives for the storage, processing, and disposal of civilian and defense used nuclear fuel, high-level waste, and materials derived from nuclear activities. The Blue Ribbon Commission report will be only advisory and is expected to be submitted by 2012. 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.

In 1984, the DOE entered into a contract with UE to dispose of nuclear waste from its Callaway nuclear plant. As a result of DOE s failure to build a repository for nuclear waste or otherwise fulfill its contract obligations, UE and other nuclear power plant owners sued DOE to recover costs incurred for ongoing storage of their spent fuel. UE seeks to recover approximately $13 million in costs that it incurred through 2009. This amount includes the cost of reracking the Callaway nuclear plant s spent fuel pool, as well as certain NRC fees, and Missouri ad valorem taxes that UE would not have incurred had DOE performed its contractual obligations. UE filed its claim in 2004, but its case was formally stayed by the United States Court of Federal Claims until 2010, pending developments in other cases that were more procedurally advanced. Discovery has been scheduled to be completed by July 28, 2011, and the trial is expected to be held in the fall of 2011 or the spring of 2012. In December 2010, UE and DOE began investigating settlement options. At this time, UE does not know nor can it predict the result of the ongoing settlement discussions between the parties.

UE intends to submit a license extension application with the NRC to extend its Callaway nuclear plant s operating license from 2024 to 2044. If the Callaway nuclear plant s license is extended, additional spent fuel storage will be required. UE is evaluating the installation of a dry spent fuel storage facility at its Callaway nuclear plant.

Electric utility rates charged to customers provide for the recovery of the Callaway nuclear plant s decommissioning costs, which include decontamination, dismantling, and site restoration costs, over an assumed 40-year life of the plant, ending with the expiration of the plant s operating license in 2024. It is assumed that the Callaway nuclear plant site will be decommissioned based on the immediate dismantlement method and removed from service. Ameren and UE have recorded an ARO for the Callaway nuclear plant decommissioning costs at fair value, which represents the present value of estimated future cash outflows. Decommissioning costs are included in the costs of service used to establish electric rates for UE s customers. These costs amounted to $7 million in each of the years 2010, 2009, and 2008. Every three years, the MoPSC requires UE to file an updated cost study for decommissioning its Callaway nuclear plant. Electric rates may be adjusted at such times to reflect changed estimates. The latest cost study filed in September 2008 included the minor tritium contamination discovered on the Callaway nuclear plant site, which did not result in a significant increase in the decommissioning cost estimate. Amounts collected from customers are deposited in an external trust fund to provide for the Callaway nuclear plant s decommissioning. If the assumed return on trust assets is not earned, we believe that 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 as Nuclear Decommissioning Trust Fund in Ameren s Consolidated Balance Sheet and UE s Balance Sheet. This amount is legally restricted and may be used only 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, with an offsetting adjustment to the related regulatory asset. See Note 9 Nuclear Decommissioning Trust Fund Investments for additional information.

NOTE 11 RETIREMENT BENEFITS

The primary objective of the Ameren retirement plan and postretirement benefit plans is to provide eligible employees with pension and postretirement health care and life insurance benefits. Ameren offers defined benefit and postretirement benefit plans covering substantially all of its employees. Ameren uses a measurement date of December 31 for its pension and postretirement benefit plans.

The following table presents the benefit liability recorded on the balance sheets of each of the Ameren Companies as of December 31, 2010:

Ameren[(a)]	$	1,052
UE		372
AIC		414
Genco		88

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

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Ameren recognizes the underfunded status of its pension and postretirement plans as a liability on its balance sheet, with offsetting entries to accumulated OCI and regulatory assets, in accordance with authoritative accounting guidance. The following table presents the funded status of our pension and postretirement benefit plans as of December 31, 2010 and 2009. It also provides the amounts included in regulatory assets and accumulated OCI at December 31, 2010 and 2009, that have not been recognized in net periodic benefit costs.

	2010		2009	
	Pension Benefits[a]	**Postretirement Benefits[a]**	**Pension Benefits[a]**	**Postretirement Benefits[a]**
Accumulated benefit obligation at end of year	**$ 3,246**	**$ (b)**	$ 3,041	$ (b)
Change in benefit obligation:				
Net benefit obligation at beginning of year	**$ 3,255**	**$ 1,143**	$ 3,303	$ 1,182
Service cost	**68**	**20**	68	19
Interest cost	**185**	**62**	186	66
Plan amendments[c]	**(40)**	**-**	-	-
Participant contributions	**-**	**17**	-	17
Actuarial (gain) loss	**165**	**(53)**	(133)	(74)
Benefits paid	**(182)**	**(74)**	(169)	(72)
Federal subsidy on benefits paid	**(b)**	**5**	(b)	5
Net benefit obligation at end of year	**3,451**	**1,120**	3,255	1,143
Change in plan assets:				
Fair value of plan assets at beginning of year	**2,495**	**732**	2,393	593
Actual return on plan assets	**328**	**81**	172	140
Employer contributions	**81**	**36**	99	49
Federal subsidy on benefits paid	**(b)**	**5**	(b)	5
Participant contributions	**-**	**17**	-	17
Benefits paid	**(182)**	**(74)**	(169)	(72)
Fair value of plan assets at end of year	**2,722**	**797**	2,495	732
Funded status deficiency	**729**	**323**	760	411
Accrued benefit cost at December 31	**$ 729**	**$ 323**	$ 760	$ 411
Amounts recognized in the balance sheet consist of:				
Current liability	**$ 4**	**$ 3**	$ 3	$ 3
Noncurrent liability	**725**	**320**	757	408
Total	**$ 729**	**$ 323**	$ 760	$ 411
Amounts recognized in regulatory assets consist of:				
Net actuarial loss	**$ 507**	**$ 86**	$ 487	$ 167
Prior service cost (credit)	**(11)**	**(32)**	33	(37)
Transition obligation	**-**	**5**	-	9
Amounts recognized in accumulated OCI consist of:				
Net actuarial loss	**24**	**13**	28	25
Prior service cost (credit)	**4**	**(10)**	8	(13)
Total	**$ 524**	**$ 62**	$ 556	$ 151

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Not applicable.
(c) In July 2010, Ameren s pension plan was amended to adjust the calculation of the future benefit obligation of approximately 700 management employees from a traditional, final pay formula to a cash balance formula.

The following table presents the assumptions used to determine our benefit obligations at December 31, 2010, and 2009:

	Pension Benefits		Postretirement Benefits	
	2010	**2009**	**2010**	**2009**
Discount rate at measurement date	**5.25%**	5.75%	**5.25%**	5.75%
Increase in future compensation	**3.50**	3.50	**3.50**	3.50
Medical cost trend rate (initial)	**-**	-	**6.00**	6.50
Medical cost trend rate (ultimate)	**-**	-	**5.00**	5.00

Years to ultimate rate	**-**	-	**2 years**	3 years

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Ameren determines discount rate assumptions by using an interest rate yield curve pursuant to authoritative accounting guidance on the determination of discount rates used for defined benefit plan obligations. The yield curve is based on the yields of more than 500 high-quality corporate bonds with maturities between zero and 30 years. A theoretical spot-rate curve constructed from this yield curve is then used as a guide to develop a discount rate matching the plans payout structure.

Funding

Pension benefits are based on the employees years of service and compensation. Ameren s pension plan is funded in compliance with income tax regulations and federal funding or regulatory requirements. As a result, Ameren expects to fund its pension plan at a level equal to the greater of the pension expense or the legally required minimum contribution. Considering Ameren s assumptions at December 31, 2010, its investment performance in 2010, and its pension funding policy, Ameren expects to make annual contributions of $75 million to $110 million in each of the next five years, with aggregate estimated contributions of $470 million. We expect UE s, AIC s and Genco s portion of the future funding requirements to be 63%, 28%, and 9%, respectively. These amounts are estimates. They may change based on actual investment performance, changes in interest rates, changes in our assumptions, any pertinent changes in government regulations, and any voluntary contributions. Our funding policy for postretirement benefits is primarily to fund the Voluntary Employee Beneficiary Association (VEBA) trusts to match the annual postretirement expense.

The following table presents the cash contributions made to our defined benefit retirement plan and to our postretirement plans during 2010 and 2009:

	Pension Benefits		Postretirement Benefits	
	2010	**2009**	**2010**	**2009**
Ameren[(a)]	**$ 81**	$ 99	**$ 36**	$ 49
UE	**36**	42	**11**	13
AIC	**23**	25	**20**	28
Genco	**4**	10	**-**	-

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

Investment Strategy and Policies

Ameren manages plan assets in accordance with the prudent investor guidelines contained in ERISA. The investment committee, to the extent authority is delegated to it by the finance committee of Ameren s board of directors, implements investment strategy and asset allocation guidelines for the plan assets. The investment committee is composed of members of senior management. The investment committee s goals are twofold: first, to ensure that sufficient funds are available to provide the benefits at the time they are payable, and second, to maximize total return on plan assets and minimize expense volatility consistent with its tolerance for risk. Ameren delegates investment management to specialists in each asset class. As appropriate, Ameren provides the investment manager with guidelines that specify allowable and prohibited investment types. The investment committee regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets assumption is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Projected rates of return for each asset class were estimated after an analysis of historical experience, future expectations, and the volatility of the various asset classes. After considering the target asset allocation for each asset class, we adjusted the overall expected rate of return for the portfolio for historical and expected experience of active portfolio management results compared with benchmark returns and for the effect of expenses paid from plan assets. Ameren will utilize an expected return on plan assets for its pension plan assets and postretirement plan assets of 8% and 7.75%, respectively, in 2011. No plan assets are expected to be returned to Ameren during 2011.

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Ameren s investment committee strives to assemble a portfolio of diversified assets that does not create a significant concentration of risks. The investment committee develops asset allocation guidelines between asset classes, and it creates diversification through investments in assets that differ by type (equity, debt, real estate, private equity), duration, market capitalization, country, style (growth or value) and industry, among other factors. The diversification of assets is displayed in the target allocation table below. The investment committee also routinely rebalances the plan assets to adhere to the diversification goals. The investment committee s strategy reduces the concentration of investment risk; however, Ameren is still subject to overall market risk. The following table presents our target allocations for 2011 and our pension and postretirement plans asset categories as of December 31, 2010, and 2009.

Asset Category	Target Allocation 2011	Percentage of Plan Assets at December 31, 2010	2009
Pension Plan:			
Cash and cash equivalents	0 - 5 %	**1%**	1%
Equity securities:			
U.S. large capitalization	29 - 39	**31**	32
U.S. small and mid-capitalization	2 - 12	**11**	10
International and emerging markets	9 - 19	**15**	15
Total equity	50 - 60	**57**	57
Debt securities	35 - 45	**37**	37
Real estate	0 - 9	**4**	4
Private equity	0 - 4	**1**	1
Total		**100%**	100%
Postretirement Plans:			
Cash and cash equivalents	0 - 10%	**4%**	4%
Equity securities:			
U.S. large capitalization	33 - 43	**39**	39
U.S. small and mid-capitalization	3 - 13	**10**	10
International	10 - 20	**14**	12
Total equity	55 - 65	**63**	61
Debt securities	30 - 40	**33**	35
Total		**100%**	100%

In general, the U.S. large capitalization equity investments are passively managed or indexed, whereas the international, emerging markets, U.S. small capitalization, and U.S. mid capitalization equity investments are actively managed by investment managers. Debt securities include a broad range of fixed income vehicles. Debt security investments in high-yield securities, emerging market securities, and non-U.S. dollar-denominated securities are owned by the plans, but in limited quantities to reduce risk. Most of the debt security investments are under active management by investment managers. Real estate investments include private real estate vehicles; however, Ameren does not, by policy, hold direct investments in real estate property. Ameren s investment in private equity funds consists of 10 different limited partnerships, with invested capital ranging from $200,000 to $10 million individually, which invest primarily in a diversified number of small U.S.-based companies. No further commitments may be made to private equity investments without approval by the finance committee of the board of directors. Additionally, Ameren s investment committee allows investment managers to use derivatives, such as index futures, exchange traded funds, foreign exchange futures, and options, in certain situations, to increase or to reduce market exposure in an efficient and timely manner.

Fair Value Measurements of Plan Assets

Investments in the pension and postretirement benefit plans were stated at fair value as of December 31, 2010. The fair value of an asset is the amount that would be received upon sale in an orderly transaction between market participants at the measurement date. Cash and cash equivalents have initial maturities of three months or less and are recorded at cost plus accrued interest. The carrying amounts of cash and cash equivalents approximate fair value because of the short-term nature of these instruments. Investments traded in active markets on national or international securities exchanges are valued at closing prices on the last business day on or before the measurement date. Securities traded in over-the-counter markets are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Derivative contracts are valued at fair value, as determined by the investment managers (or independent third parties on behalf of the investment managers), who use proprietary models and take into consideration exchange quotations on underlying instruments, dealer quotations, and other market information. The fair value of real estate is based on annual appraisal reports prepared by an independent real estate appraiser.

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The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 Fair Value Measurements, the pension plan assets measured at fair value as of December 31, 2010:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ -	$ 20	$ -	$ 20
Equity securities:				
U.S. large capitalization	70	812	-	882
U.S. small and mid-capitalization	299	10	-	309
International and emerging markets	129	284	-	413
Debt securities:				
Corporate bonds	-	646	-	646
Municipal bonds	-	129	-	129
U.S. treasury and agency securities	-	154	-	154
Asset-backed securities	-	-	-	-
Other	-	100	-	100
Real estate	-	-	98	98
Private equity	-	-	28	28
Derivative assets	1	-	-	1
Derivative liabilities	(1)	-	-	(1)
Total	$ 498	$ 2,155	$ 126	$ 2,779[(a)(b)]

(a) Includes $85 million of medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code (401(h) accounts) to fund a portion of the postretirement obligation.

(b) Excludes $28 million of receivables related to pending security sales, offset by payables related to pending security purchases.

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 Fair Value Measurements, the pension plan assets measured at fair value as of December 31, 2009:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ 1	$ 35	$ -	$ 36
Equity securities:				
U.S. large capitalization	270	556	-	826
U.S. small and mid-capitalization	242	10	-	252
International and emerging markets	114	264	-	378
Debt securities:				
Corporate bonds	-	579	-	579
Municipal bonds	-	44	-	44
U.S. treasury and agency securities	-	209	-	209
Asset-backed securities	-	19	-	19
Other	-	102	1	103
Real estate	-	-	90	90
Private equity	-	-	33	33

Derivative assets	-	4	-	4
Total	$ 627	$ 1,822	$ 124	$ 2,573[(a)(b)]

(a) Includes $77 million of medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code (401(h) accounts) to fund a portion of the postretirement obligation.

(b) Excludes $1 million net payable related to pending security purchases.

For the year ended December 31, 2009, $183 million of previously classified Level 1 assets within the pension plan were recategorized to Level 2. The classification change primarily related to U.S. treasury securities and has been reflected in the above table.

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The following table summarizes the changes in the fair value of the pension plan assets classified as Level 3 in the fair value hierarchy for each of the years ended December 31, 2010 and 2009:

	Beginning Balance at January 1,	Actual Return on Plan Assets Related to Assets Still Held at the Reporting Date	Actual Return on Plan Assets Related to Assets Sold During the Period	Purchases, Sales, and Settlements, net	Net Transfers into (out of) of Level 3	Ending Balance at December 31,
2010:						
Other debt securities	**$ 1**	**$ -**	**$ -**	**$ (1)**	**$ -**	**$ -**
Real estate	**90**	**7**	**-**	**1**	**-**	**98**
Private equity	**33**	**(5)**	**7**	**(7)**	**-**	**28**
2009:						
Other debt securities	$ 1	$ -	$ -	$ -	$ -	$ 1
Real estate	144	(53)	(2)	1	-	90
Private equity	39	(6)	3	(3)	-	33

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 Fair Value Measurements, the postretirement benefit plans assets measured at fair value as of December 31, 2010:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ -	$ 35	$ -	$ 35
Equity securities:				
U.S. large capitalization	215	72	-	287
U.S. small and mid-capitalization	66	-	-	66
International	43	51	-	94
Debt securities:				
Corporate bonds	-	59	-	59
Municipal bonds	-	58	-	58
U.S. treasury and agency securities	-	59	-	59
Asset-backed securities	-	31	-	31
Other	-	29	-	29
Total	$ 324	$ 394	$ -	$ 718[(a)(b)]

(a) Excludes $85 million of medical benefit (health and welfare) component for 401(h) accounts to fund a portion of the postretirement obligation. These 401(h) assets are included in the pension plan assets shown above.
(b) Excludes $6 million of payables related to pending security purchases, offset by Medicare, interest receivables, and receivables related to pending security sales.

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 Fair Value Measurements, the postretirement benefit plans assets measured at fair value as of December 31, 2009:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ 1	$ 26	$ -	$ 27
Equity securities:				
U.S. large capitalization	193	60	-	253
U.S. small and mid-capitalization	64	-	-	64
International	35	45	-	80
Debt securities:				
Corporate bonds	-	69	-	69
Municipal bonds	-	58	-	58
U.S. treasury and agency securities	-	49	-	49
Asset-backed securities	-	23	-	23
Other	-	28	-	28
Derivative assets	1	-	-	1
Total	$ 294	$ 358	$ -	$ 652(a)(b)

(a) Excludes $77 million of medical benefit (health and welfare) component for 401(h) accounts to fund a portion of the postretirement obligation. These 401(h) assets are included in the pension plan assets shown above.

(b) Excludes net $3 million of Medicare and interest receivables, offset by payables related to pending security purchases.

For the year ended December 31, 2009, $17 million of previously classified Level 1 assets within the postretirement benefit plans were recategorized to Level 2. The classification change primarily related to U.S. treasury securities and has been reflected in the above table.

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Net Periodic Benefit Cost

The following table presents the components of the net periodic benefit cost of our pension and postretirement benefit plans during 2010, 2009, and 2008:

	Pension Benefits Ameren[(a)]	Postretirement Benefits Ameren[(a)]
2010:		
Service cost	**$ 68**	**$ 20**
Interest cost	**185**	**62**
Expected return on plan assets	**(212)**	**(56)**
Amortization of:		
Transition obligation	**-**	**2**
Prior service cost	**6**	**(8)**
Actuarial loss	**18**	**1**
Net periodic benefit cost	**$ 65**	**$ 21**
2009:		
Service cost	$ 68	$ 19
Interest cost	186	66
Expected return on plan assets	(206)	(54)
Amortization of:		
Transition obligation	-	2
Prior service cost	9	(8)
Actuarial loss	24	9
Net periodic benefit cost	$ 81	$ 34
2008:		
Service cost	$ 60	$ 18
Interest cost	186	70
Expected return on plan assets	(213)	(58)
Amortization of:		
Transition obligation	-	2
Prior service cost	11	(8)
Actuarial loss	3	9
Net periodic benefit cost	$ 47	$ 33

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

The current year expected return on plan assets is primarily determined by adjusting the prior-year market-related asset value for current year contributions, disbursements, and expected return, plus 25% of the actual return in excess of (or less than) expected return for the four prior years.

The estimated amounts that will be amortized from regulatory assets and accumulated OCI into net periodic benefit cost in 2011 are as follows:

	Pension Benefits Ameren[(a)]	Postretirement Benefits Ameren[(a)]
Regulatory assets:		
Transition obligation	$ -	$ 3
Prior service cost (credit)	(1)	(4)
Net actuarial loss	54	14
Accumulated OCI:		
Transition obligation	-	-
Prior service cost (credit)	-	(3)
Net actuarial loss	1	-
Total	$ 54	$ 10

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

Prior service cost is amortized on a straight-line basis over the average future service of active participants benefiting under the plan amendment. The net actuarial loss subject to amortization is amortized on a straight-line basis over 10 years.

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UE, AIC and Genco are responsible for their share of the pension and postretirement benefit costs. The following table presents the pension costs and the postretirement benefit costs incurred for the years ended December 31, 2010, 2009, and 2008:

	Pension Costs			Postretirement Costs		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Ameren[(a)]	**$ 65**	$ 81	$ 47	**$ 21**	$ 34	$ 33
UE	**42**	50	35	**11**	15	13
AIC	**10**	14	1	**7**	16	17
Genco	**9**	11	6	**2**	3	2

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

The expected pension and postretirement benefit payments from qualified trust and company funds and the federal subsidy for postretirement benefits related to prescription drug benefits, which reflect expected future service, as of December 31, 2010, are as follows:

	Pension Benefits		Postretirement Benefits		
	Paid from Qualified Trust	**Paid from Company Funds**	**Paid from Qualified Trust**	**Paid from Company Funds**	**Federal Subsidy**
2011	$ 199	$ 4	$ 71	$ 3	$ 5
2012	207	3	73	3	5
2013	214	2	77	3	5
2014	222	2	80	3	5
2015	229	2	83	3	6
2016 - 2020	1,253	11	462	16	31

The following table presents the assumptions used to determine net periodic benefit cost for our pension and postretirement benefit plans for the years ended December 31, 2010, 2009, and 2008:

	Pension Benefits			Postretirement Benefits		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Discount rate at measurement date	**5.75%**	5.75%	6.15%	**5.75%**	5.75%	6.05%
Expected return on plan assets	**8.00**	8.00	8.25	**8.00**	8.00	8.25
Increase in future compensation	**3.50**	4.00	4.00	**3.50**	4.00	4.00
Medical cost trend rate (initial)	**-**	-	-	**6.50**	7.00	9.00
Medical cost trend rate (ultimate)	**-**	-	-	**5.00**	5.00	5.00
Years to ultimate rate	**-**	-	-	**3 years**	4 years	4 years

The table below reflects the sensitivity of Ameren s plans to potential changes in key assumptions:

	Pension Benefits		Postretirement Benefits	
	Service Cost and Interest Cost	**Projected Benefit Obligation**	**Service Cost and Interest Cost**	**Postretirement Benefit Obligation**
0.25% decrease in discount rate	$ -	$ 101	$ -	$ 29
0.25% increase in salary scale	2	13	-	-
1.00% increase in annual medical trend	-	-	2	31
1.00% decrease in annual medical trend	-	-	(2)	(29)

Other

Ameren sponsors a 401(k) plan for eligible employees. The Ameren plan covered all eligible employees of the Ameren Companies at December 31, 2010. The plans allowed employees to contribute a portion of their compensation in accordance with specific guidelines. Ameren matched a percentage of the employee contributions up to certain limits. Ameren s matching contributions to the 401(k) plan totaled $27 million, $24 million, and $23 million in 2010, 2009, and 2008, respectively.

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The following table presents the portion of the 401(k) matching contribution to the Ameren plan attributable to each of the Ameren Companies for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Ameren[(a)]	**$ 27**	$ 24	$ 23
UE	**16**	14	14
AIC	**8**	7	6
Genco	**1**	2	2

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

NOTE 12 STOCK-BASED COMPENSATION

Ameren s long-term incentive plan for eligible employees, called the Long-term Incentive Plan of 1998 (1998 Plan), was replaced prospectively by the 2006 Omnibus Incentive Compensation Plan (2006 Plan) effective May 2, 2006. The 2006 Plan provides for a maximum of 4 million common shares to be available for grant to eligible employees and directors. No new awards may be granted under the 1998 Plan; however, previously granted awards continue to vest or to be exercisable in accordance with their original terms and conditions. The 2006 Plan awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance share units, cash-based awards, and other stock-based awards.

A summary of nonvested shares at December 31, 2010, and changes during the year ended December 31, 2010, under the 1998 Plan and the 2006 Plan are presented below:

	Performance Share Units[(a)]		Restricted Shares[(b)]	
	Share Units	Weighted-average Fair Value per Unit	Shares	Weighted-average Fair Value per Share
Nonvested at January 1, 2010	945,337	$ 22.07	135,696	$ 48.92
Granted[(c)]	688,510	32.01	-	-
Dividends	-	-	4,655	26.71
Unearned or forfeited[(d)]	(345,958)	31.65	(4,369)	49.71
Earned and vested[(e)]	(145,121)	31.55	(52,828)	47.43
Nonvested at December 31, 2010	1,142,768	$ 23.96	83,154	$ 49.87

(a) Granted under the 2006 Plan.
(b) Granted under the 1998 Plan.
(c) Includes performance share units (share units) granted to certain executive and nonexecutive officers and other eligible employees in January 2010 under the 2006 Plan.
(d) Includes share units granted in 2008 that were not earned based on performance provisions of the award grants.
(e) Includes share units granted in 2008 that vested as of December 31, 2010, that were earned pursuant to the provisions of the award grants. Also includes share units that vested due to attainment of retirement eligibility by certain employees. Actual shares issued for retirement-eligible employees will vary depending on actual performance over the three-year measurement period.

Ameren recorded compensation expense of $14 million, $15 million, and $22 million for the years ended December 31, 2010, 2009, and 2008, respectively, and a related tax benefit of $5 million, $6 million, and $8 million for the years ended December 31, 2010, 2009, and 2008, respectively. As of December 31, 2010, total compensation cost of $13 million related to nonvested awards not yet recognized is expected to be recognized over a weighted-average period of 23 months.

Performance Share Units

Performance share unit awards were granted under the 2006 Plan each year since 2006. A share unit will vest and

entitle an employee to receive shares of Ameren common stock (plus accumulated dividends) if, at the end of the three-year performance period, certain specified performance or market conditions have been met and the individual remains employed by Ameren. The exact number of shares issued pursuant to a share unit will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. For performance share units granted in 2006, 2007 and 2008, vested performance shares units are held for a two-year period before being paid to the employee in shares of Ameren common stock. During this two-year hold period, the employee is paid dividend equivalents on a current basis.

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The fair value of each share unit awarded in January 2010 under the 2006 Plan was determined to be $32.01. That amount was based on Ameren s closing common share price of $27.95 at December 31, 2009, and lattice simulations. Lattice simulations are used to estimate expected share payout based on Ameren s total stockholder return for a three-year performance period relative to the designated peer group beginning January 1, 2010. The significant assumptions used to calculate fair value also included a three-year risk-free rate of 1.70%, volatility of 23% to 39% for the peer group, and Ameren s attainment of three-year average earnings per share threshold during each year of the performance period.

The fair value of each share unit awarded in March 2009 under the 2006 Plan was determined to be $15.52. That amount was based on Ameren s closing common share price of $22.20 at March 2, 2009, and lattice simulations. Lattice simulations are used to estimate

expected share payout based on Ameren s total shareholder return for a three-year performance period relative to the designated peer group beginning January 1, 2009. The significant assumptions used to calculate fair value also included a three-year risk-free rate of 1.24%, volatility of 21.3% to 33.1% for the peer group, and Ameren s attainment of earnings per share of at least $2.54 during each year of the three-year performance period.

Restricted Stock

Restricted stock awards of Ameren common stock were granted under the 1998 Plan from 2001 to 2005. Restricted shares have the potential to vest over a seven-year period from the date of grant if Ameren achieves certain performance levels. An accelerated vesting provision included in this plan reduces the vesting period from seven years to three years if the earnings growth rate exceeds a prescribed level.

NOTE 13 INCOME TAXES

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, 2010, 2009, and 2008:

	Ameren	UE	AIC	Genco
2010:				
Statutory federal income tax rate:	**35%**	**35%**	**35%**	**35%**
Increases (decreases) from:				
Non-deductible impairment of goodwill	**32**	**-**	**-**	**(144)**
Production activities deduction	**-**	**-**	**-**	**7**
Depreciation differences	**(4)**	**(3)**	**-**	**-**
Amortization of investment tax credit	**(2)**	**(1)**	**(1)**	**4**
State tax	**8**	**3**	**5**	**(14)**
Reserve for uncertain tax positions	**(1)**	**-**	**-**	**(6)**
Tax credits	**(3)**	**-**	**-**	**13**
Change in federal tax law(a)	**3**	**1**	**-**	**(19)**
Other permanent items(b)	**-**	**-**	**-**	**(1)**
Effective income tax rate	**68%**	**35%**	**39%**	**(125)%**
2009:				
Statutory federal income tax rate:	35%	35%	35%	35%
Increases (decreases) from:				
Depreciation differences	(1)	(3)	(1)	-
Amortization of investment tax credit	(1)	(1)	(1)	-
State tax	5	3	5	4
Reserve for uncertain tax positions	(1)	-	-	-
Permanent items(c)	(1)	-	(1)	(1)
Tax credits	(1)	(1)	-	-
Effective income tax rate	35%	33%	37%	38%
2008:				
Statutory federal income tax rate:	35%	35%	35%	35%
Increases (decreases) from:				
Depreciation differences	-	(1)	(3)	-
Amortization of investment tax credit	(1)	(1)	(5)	-

State tax	4	3	4	5
Reserve for uncertain tax positions	(1)	(1)	-	(1)
Permanent items[(d)]	(1)	1	(3)	(2)
Tax credits	(1)	-	-	-
Other[(e)]	(1)	-	-	-
Effective income tax rate	34%	36%	28%	37%

(a) Relates to change in taxation of prescription drug benefits to retiree participants from the enactment in 2010 of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Bill of 2010.

(b) Permanent items are treated differently for book and tax purposes and primarily include nondeductible expenses for Genco.
(c) Permanent items are treated differently for book and tax purposes and primarily include Internal Revenue Code Section 199 production activity deductions for Ameren and Genco, company-owned life insurance for Ameren and AIC, employee stock ownership plan dividends for Ameren, and nondeductible expenses for AIC.
(d) Permanent items are treated differently for book and tax purposes and primarily include Internal Revenue Code Section 179 production activity deductions for Ameren, UE and Genco and company-owned life insurance for AIC.
(e) Primarily includes settlements with state taxing authorities and state apportionment changes for Ameren.

The following table presents the components of income tax expense (benefit) for the years ended December 31, 2010, 2009, and 2008:

	Ameren[(a)]	UE	AIC	Genco
2010:				
Current taxes:				
Federal	**$ 13**	**$ (14)**	**$ (20)**	**$ (5)**
State	**10**	**(15)**	**(5)**	**6**
Deferred taxes:				
Federal	**274**	**206**	**132**	**22**
State	**36**	**27**	**32**	**(2)**
Deferred investment tax credits, amortization	**(8)**	**(5)**	**(2)**	**(1)**
Total income tax expense	**$ 325**	**$ 199**	**$ 137**	**$ 20**
2009:				
Current taxes:				
Federal	$ (73)	$ (117)	$ (8)	$ 22
State	3	(31)	14	14
Deferred taxes:				
Federal	337	239	64	57
State	74	42	11	9
Deferred investment tax credits, amortization	(9)	(5)	(2)	(1)
Total income tax expense	$ 332	$ 128	$ 79	$ 101
2008:				
Current taxes:				
Federal	$ 165	$ 37	$ (1)	$ 132
State	10	5	(5)	28
Deferred taxes:				
Federal	130	86	17	21
State	31	11	8	2
Deferred investment tax credits, amortization	(9)	(5)	(3)	(1)
Total income tax expense	$ 327	$ 134	$ 16	$ 182

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

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The following table presents the deferred tax assets and deferred tax liabilities recorded as a result of temporary differences at December 31, 2010, and 2009:

	Ameren[(a)]	UE	AIC	Genco
2010:				
Accumulated deferred income taxes, net liability (asset):				
Plant related	**$ 3,310**	**$ 1,974**	**$ 750**	**$ 378**
Deferred intercompany tax gain/basis step-up	**2**	**(2)**	**71**	**(68)**
Regulatory assets (liabilities), net	**67**	**68**	**(1)**	**-**
Deferred benefit costs	**(323)**	**(87)**	**(86)**	**(45)**
Purchase accounting	**65**	**-**	**(1)**	**17**
ARO	**(48)**	**(9)**	**1**	**(27)**
Other	**(116)**	**7**	**(53)**	**10**
Total net accumulated deferred income tax liabilities[(b)]	**$ 2,957**	**$ 1,951**	**$ 681**	**$ 265**
2009:				
Accumulated deferred income taxes, net liability (asset):				
Plant related	$ 2,813	$ 1,717	$ 553	$ 332
Deferred intercompany tax gain/basis step-up	3	(3)	79	(77)
Regulatory assets (liabilities), net	52	54	(2)	-
Deferred benefit costs	(313)	(98)	(68)	(31)
Purchase accounting	63	-	(27)	27
ARO	(43)	(9)	-	(23)
Other	17	11	(26)	14
Total net accumulated deferred income tax liabilities[(c)]	$ 2,592	$ 1,672	$ 509	$ 242

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Includes $43 million as current assets recorded in the balance sheet for AIC. Includes $71 million, $43 million, and $12 million as current liabilities recorded in the balance sheets for Ameren, UE and Genco, respectively.
(c) Includes $45 million as current assets recorded in the balance sheet for AIC. Includes $38 million, $12 million and $26 million as current liabilities recorded in the balance sheets for Ameren, UE and Genco, respectively.

The following table presents the components of deferred tax assets relating to net operating loss carryforwards and tax credit carryforwards at December 31, 2010:

	Ameren	UE	AIC	Genco
Net operating loss carryforwards:				
Federal[(a)]	$ 73	$ 37	$ 14	$ 2
State[(b)]	7	-	3	-
Total net operating loss carryforwards	$ 80	$ 37	$ 17	$ 2
Tax credit carryforwards:				
Federal[(c)]	$ 78	$ 11	$ -	$ -
State[(d)]	26	-	1	3
Total tax credit carryforwards	$ 104	$ 11	$ 1	$ 3

(a) These will begin to expire in 2028.
(b) These will begin to expire in 2017.
(c) These will begin to expire in 2029.
(d) These will begin to expire in 2011.

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Uncertain Tax Positions

A reconciliation of the change in the unrecognized tax benefit balance during the years ended December 31, 2008, 2009 and 2010, is as follows:

	Ameren	UE	AIC	Genco
Unrecognized tax benefits January 1, 2008	$ 116	$ 26	$ -	$ 40
Increases based on tax positions prior to 2008	16	2	-	5
Decreases based on tax positions prior to 2008	(46)	(13)	-	(9)
Increases based on tax positions related to 2008	31	6	-	13
Changes related to settlements with taxing authorities	(7)	(1)	-	(1)
Decreases related to the lapse of statute of limitations	-	-	-	-
Unrecognized tax benefits December 31, 2008	$ 110	$ 20	$ -	$ 48
Increases based on tax positions prior to 2009	90	76	-	9
Decreases based on tax positions prior to 2009	(84)	(19)	-	(31)
Increases based on tax positions related to 2009	19	11	-	3
Changes related to settlements with taxing authorities	-	-	-	-
Decreases related to the lapse of statute of limitations	-	-	-	-
Unrecognized tax benefits December 31, 2009	$ 135	$ 88	$ -	$ 29
Increases based on tax positions prior to 2010	**72**	**40**	**27**	**4**
Decreases based on tax positions prior to 2010	**(38)**	**(12)**	**(2)**	**(16)**
Increases based on tax positions related to 2010	**77**	**48**	**31**	**3**
Changes related to settlements with taxing authorities	**-**	**-**	**-**	**-**
Decreases related to the lapse of statute of limitations	**-**	**-**	**-**	**-**
Unrecognized tax benefits December 31, 2010	**$ 246**	**$ 164**	**$ 56**	**$ 20**
Total unrecognized tax benefits (detriments) that, if recognized, would impact the effective tax rates as of December 31, 2008	$ 12	$ 1	$ -	$ (2)
Total unrecognized tax benefits that, if recognized, would impact the effective tax rates as of December 31, 2009	$ 6	$ 3	$ -	$ -
Total unrecognized tax benefits that, if recognized, would impact the effective tax rates as of December 31, 2010	**$ -**	**$ 3**	**$ -**	**$ 1**

The Ameren Companies recognize interest charges (income) and penalties accrued on tax liabilities on a pretax basis as interest charges (income) or miscellaneous expense in the statements of income.

A reconciliation of the change in the liability for interest on unrecognized tax benefits during the years ended December 31, 2008, 2009 and 2010, is as follows:

	Ameren	UE	AIC	Genco
Liability for interest January 1, 2008	$ 17	$ 5	$ 1	$ 7
Interest income for 2008	(7)	(3)	(1)	(3)
Liability for interest December 31, 2008	$ 10	$ 2	$	$ 4
Interest charges (income) for 2009	(2)	2		(2)
Liability for interest December 31, 2009	$ 8	$ 4	$	$ 2
Interest charges for 2010	**9**	**6**	**2**	
Liability for interest December 31, 2010	**$ 17**	**$ 10**	**$ 2**	**$ 2**

As of January 1, 2008, December 31, 2008, December 31, 2009, and December 31, 2010, the Ameren Companies have accrued no amount for penalties with respect to unrecognized tax benefits.

Ameren s federal income tax returns for the years 2005 through 2008 are before the Appeals Office of the Internal Revenue Service. The Internal Revenue Service is currently examining Ameren s 2009 income tax return.

State income tax returns are generally subject to examination for a period of three years after filing of the return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. The Ameren Companies do not currently have material state income tax issues under examination, administrative appeals, or litigation.

It is reasonably possible that events will occur during the next 12 months that would cause the total amount of unrecognized tax benefits for the Ameren Companies to increase or decrease. However, the Ameren Companies do not believe such increases or decreases would be material to their results of operations, financial position or liquidity.

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NOTE 14 RELATED PARTY TRANSACTIONS

The Ameren Companies have engaged in, and may in the future engage in, affiliate transactions in the normal course of business. These transactions primarily consist of natural gas and power purchases and sales, services received or rendered, and borrowings and lendings. Transactions between affiliates are reported as intercompany transactions on their financial statements, but are eliminated in consolidation for Ameren s financial statements. Below are the material related party agreements.

Electric Power Supply Agreements

The following table presents the amount of physical gigawatthour sales under related party electric power supply agreements for the years ended December 31, 2010, 2009, and 2008:

	December 31,		
	2010	**2009**	**2008**
Genco sales to Marketing Company[(a)]	**21,656**	19,598	23,701
Marketing Company sales to AIC[(b)]	**948**	3,529	5,829

(a) Genco has a power supply agreement with Marketing Company whereby Genco sells and Marketing Company purchases all the capacity and energy available from Genco s generation fleet.

(b) Marketing Company contracted with AIC to provide power based on the results of the September 2006 Illinois power procurement auction. The values herein reflect the physical sales volumes provided in that agreement.

Genco entered into a power supply agreement, as amended, (PSA) with Marketing Company, whereby Genco agreed to sell and Marketing Company agreed to purchase all of the capacity and energy available from Genco s generation fleet. Marketing Company entered into a similar PSA with AERG. Under the PSAs, revenues are allocated between Genco and AERG based on reimbursable expenses and generation. Each PSA will continue through December 31, 2022, and from year to year thereafter unless either party to the respective PSA elects to terminate the PSA by providing the other party with no less than six months advance written notice.

In December 2005, EEI entered into a PSA with Marketing Company, whereby EEI agreed to sell and Marketing Company agreed to purchase all of the capacity and energy available from EEI s generation fleet. The price that Marketing Company pays for capacity is set annually based upon prevailing market prices. Marketing Company pays spot market prices for the associated energy. In addition, EEI will at times purchase energy from Marketing Company to fulfill obligations to a nonaffiliated party. This PSA will continue through May 31, 2016, unless either party elects to terminate the PSA by providing the other party with no less than four years advance written notice or five days written notice in the event of a default unless default is cured within 30 business days.

Capacity Supply Agreements

AIC, as an electric load-serving entity, must acquire capacity sufficient to meet its obligations to customers.

AIC used RFP processes in early 2008, pursuant to the 2007 Illinois Electric Settlement Agreement, to contract for the necessary capacity requirements for the period from June 1, 2008, through May 31, 2009. Marketing Company and UE were two of the winning suppliers in AIC s capacity RFPs. Marketing Company contracted to supply a portion of AIC s capacity for $6 million. In addition, UE contracted to supply a portion of the AIC s capacity for $1 million.

In 2009, AIC used a RFP process, administered by the IPA, to contract capacity for the period from June 1, 2009, through May 31, 2012. Both Marketing Company and UE were among the winning suppliers in the capacity RFP process. In April 2009, Marketing Company contracted to supply some capacity to AIC for $4 million, $9 million, and $8 million for the 12 months ending May 31, 2010, 2011, and 2012, respectively. In April 2009, UE contracted to supply some capacity to AIC for $2 million, $2 million, and $1 million for the 12 months ending May 31, 2010, 2011, and 2012, respectively.

In 2010, AIC used a RFP process, administered by the IPA, to contract capacity for the period from June 1, 2010, through May 31, 2013. Both Marketing Company and UE were among winning suppliers in the capacity RFP process. In April 2010, Marketing Company contracted to supply some capacity to AIC for $1 million, $2 million, and $3 million for the 12 months ending May 31, 2011, 2012, and 2013, respectively. In

April 2010, UE contracted to supply some capacity to AIC for less than $1 million for the period from June 1, 2010, through May 31, 2013.

Energy Swaps

As part of the 2007 Illinois Electric Settlement Agreement, AIC entered into financial contracts with Marketing Company (for the benefit of Genco and AERG) to lock in energy prices for 400 to 1,000 megawatts annually of their round-the-clock power requirements during the period June 1, 2008, to December 31, 2012, at then-relevant market prices. These financial contracts do not include capacity, are not load-following products, and do not involve the physical delivery of energy. These financial contracts are derivative instruments. They are accounted for as cash flow hedges by Marketing Company and as derivatives subject to regulatory deferral by AIC. Consequently, AIC and Marketing Company record the fair value of the contracts on their respective balance sheets and the changes to the fair value in regulatory assets or liabilities for AIC and OCI at Marketing Company. See Note 7 Derivative Financial Instruments for additional information on these derivatives. Below are the remaining contracted volumes and prices per megawatthour as of December 31, 2010:

Period	**Volume**	**Price per Megawatthour**
January 1, 2011 December 31, 2011	1,000 MW	$ 52.06
January 1, 2012 December 31, 2012	1,000 MW	53.08

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AIC, as an electric load-serving entity, must acquire energy sufficient to meet its obligations to customers.

AIC used RFP processes in early 2008, pursuant to the 2007 Illinois Electric Settlement Agreement, to contract for the necessary financial energy swaps requirement for the period from June 1, 2008, through May 31, 2009. Marketing Company was one of the winning suppliers in AIC s energy swap RFP process. Marketing Company entered into financial instruments that fixed the price that the Ameren Illinois Utilities paid for about two million megawatthours at approximately $60 per megawatthour.

In 2009, AIC used a RFP process, administered by the IPA, to procure financial energy swaps from June 1, 2009, through May 31, 2011. Marketing Company was a winning supplier in the financial energy swap RFP process. In May 2009, Marketing Company entered into financial instruments that fixed the price that AIC will pay for approximately 80,000 megawatthours at approximately $48 per megawatthour during the 12 months ending May 31, 2010 and for approximately 89,000 megawatthours at approximately $48 per megawatthour during the 12 months ending May 31, 2011.

In 2010, AIC used a RFP process, administered by the IPA, to procure financial energy swaps for the period from June 1, 2010, through May 31, 2013. Marketing Company was a winning supplier in the financial energy swap RFP process. In May 2010, Marketing Company entered into financial instruments that fixed the price that AIC will pay for approximately 924,000 megawatthours at approximately $33 per megawatthour during the 12 months ending May 31, 2011, and for approximately 296,000 megawatthours at approximately $40 per megawatthour during the 12 months ending May 31, 2012.

Interconnection and Transmission Agreements

UE and AIC are parties to an interconnection agreement for the use of their respective transmission lines and other facilities for the distribution of power. These agreements have no contractual expiration date, but may be terminated by either party with three years notice.

Generator Interconnection Agreement

In 2008, Genco and AIC (formerly CIPS) signed an agreement requiring Genco to fund the construction costs of upgrades to AIC s transmission system. The transmission upgrades were required to support the additional electric power upgrades made at Genco s Coffeen power plant. Under the agreement, Genco paid AIC for the costs of the transmission upgrades. When the transmission assets were placed in service, AIC paid Genco, with interest, for the costs of the transmission upgrades. In 2009, AIC paid Genco $2 million when the transmission assets were placed in service. These transactions were eliminated in consolidation on Ameren s financial statements.

In September 2009, Marketing Company and AIC (formerly CIPS) signed an agreement requiring Marketing

Company to fund the cost of certain upgrades to AIC s electric transmission system. Under the agreement, Marketing Company paid AIC $5 million in 2009 for the costs of the transmission upgrades. These amounts were a contribution in aid of construction and will not be refunded to Marketing Company. These transactions were eliminated in consolidation on Ameren s financial statements.

Joint Ownership Agreement

ATXI and AIC have a joint ownership agreement to construct, own, operate, and maintain certain electric transmission assets in Illinois. Under the terms of this agreement, AIC and ATXI are responsible for their applicable share of all costs related to the construction, operation, and maintenance of electric transmission systems. Through this joint ownership agreement, AIC has a variable interest in ATXI, but AIC is not the primary beneficiary. Ameren is the primary beneficiary of ATXI, and therefore consolidates ATXI.

Support Services Agreements

Ameren Services provides support services to its affiliates. The cost of support services, including wages, employee benefits, professional services, and other expenses, are based on, or are an allocation of, actual costs incurred. AFS provided support services to its affiliates through December 31, 2010. Effective January 1, 2011, the services previously performed by AFS are performed within the Ameren Missouri, Ameren Illinois and Merchant Generation business segments.

Executory Tolling, Gas Sales, and Transportation Agreements

Prior to 2009, under an executory tolling agreement, AIC (formerly CILCO) purchased steam, chilled water, and electricity from Medina Valley. In January 2009, AIC transferred the tolling agreement to Marketing Company.

Under a gas transportation agreement, Genco acquires gas transportation service from UE for its Columbia, Missouri, CTs. This agreement expires in February 2016.

Money Pools

See Note 5 Long-term Debt and Equity Financings for discussion of affiliate borrowing arrangements.

Intercompany Borrowings

On May 1, 2005, Genco issued to AIC (formerly CIPS) an amended and restated subordinated promissory note in the principal amount of $249 million with an interest rate of 7.125% per year. Interest income and charges for this note recorded by AIC and Genco, respectively, were $1 million, $4 million, and $7 million for the years ended December 31, 2010, 2009, and 2008, respectively. Genco s subordinated note payable to AIC associated with the transfer in 2000 of AIC s electric generating assets and related liabilities to Genco matured on May 1, 2010.

Genco had no outstanding borrowings directly from Ameren at December 31, 2010, but had $131 million of

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outstanding borrowings directly from Ameren at December 31, 2009. The average interest rate on these borrowings was 2.9% for the year ended December 31, 2010 (2009 2.2%). Genco recorded interest charges of $2 million, $2 million and less than $1 million for Ameren borrowings for the years ended December 31, 2010, 2009, and 2008, respectively.

Collateral Postings

Under the terms of the 2010 and 2009 Illinois power procurement agreements entered into through a RFP process administered by the IPA, suppliers must post collateral under certain market conditions to protect AIC in the event of nonperformance. The collateral postings are unilateral, meaning that only the suppliers would be required to post collateral. Therefore, UE, as a winning supplier of capacity, and Marketing Company, as a winning supplier of capacity and financial energy swaps, may be required to post collateral. As of December 31, 2010 and 2009, there were no collateral postings required of UE or Marketing Company related to the 2010 and 2009 Illinois power procurement agreements.

Operating Leases

Under an operating lease agreement, Genco leased certain CTs at a Joppa, Illinois, site to its former parent, Development Company, for an initial term of 15 years, expiring September 30, 2015. Under an electric power supply agreement with Marketing Company, Development Company supplied the capacity and energy from these leased units to Marketing Company, which in turn supplied the energy to Genco. By mutual agreement of the parties, this lease agreement and this power supply agreement were terminated in February 2008, when an internal reorganization merged Development Company into Resources Company. Genco recorded operating revenues from the lease agreement of $2 million for the year ended December 31, 2008.

Intercompany Transfers

On January 1, 2008, UE transferred its interest in Union Electric Development Corporation at book value to Ameren by means of a $3 million dividend-in-kind. On March 31, 2008, Union Electric Development Corporation was merged into Ameren Development Company, with Ameren Development Company surviving the merger.

On February 29, 2008, UE contributed its 40% ownership interest in EEI, book value of $39 million, to Resources Company, in exchange for a 50% interest in Resources Company, and then immediately transferred its interest in Resources Company to Ameren by means of a $39 million dividend-in-kind. Also on February 29, 2008, Development Company, which formerly held a 40% ownership interest in EEI, merged into Ameren Energy Resources Company, which then merged into Resources Company. As a result, Resources Company had an 80% ownership interest in EEI.

On January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% ownership interest in EEI to Genco, through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco recognized the assets and liabilities of EEI at their book value as of January 1, 2010.

On October 1, 2010, AIC distributed AERG s common stock to Ameren in connection with the AIC Merger. Ameren subsequently contributed the AERG common stock to Resources Company. The distribution of AERG common stock was accounted for as a transaction between entities under common control; therefore, AIC transferred AERG to Ameren based on AERG s carrying value. See Note 16 Corporate Reorganization and Discontinued Operations for additional information.

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The following table presents the impact on UE, AIC and Genco, of related party transactions for the years ended December 31, 2010, 2009, and 2008. It is based primarily on the agreements discussed above and the money pool arrangements discussed in Note 4 Credit Facility Borrowings and Liquidity.

Agreement	Income Statement Line Item		UE	AIC	Genco
Genco power supply	Operating Revenues	**2010**	**$ (a)**	**$ (a)**	**$ 1,059**
agreement with Marketing Company		2009	(a)	(a)	1,071
		2008	(a)	(a)	1,307
UE ancillary services and capacity	Operating Revenues	**2010**	**2**	**(a)**	**(a)**
agreements with AIC		2009	3	(a)	(a)
		2008	13	(a)	(a)
UE and Genco gas transportation	Operating Revenues	**2010**	**1**	**(a)**	**(a)**
agreement		2009	1	(a)	(a)
		2008	1	(a)	(a)
Genco gas sales to Medina Valley	Operating Revenues	**2010**	**(a)**	**(a)**	**2**
		2009	(a)	(a)	1
Genco gas sales to distribution companies	Operating Revenues	**2010**	**(a)**	**(a)**	**1**
		2009	(a)	(a)	2
		2008	(a)	(a)	7
Total Operating Revenues		**2010**	**$ 3**	**$ (a)**	**$ 1,062**
		2009	4	(a)	1,074
		2008	14	(a)	1,314
UE and Genco gas transportation	Fuel	**2010**	**$ (a)**	**$ (a)**	**$ 1**
agreement		2009	(a)	(a)	1
		2008	(a)	(a)	1
AIC agreements with	Purchased Power	**2010**	**$ (a)**	**$ 233**	**$ (a)**
Marketing Company		2009	(a)	400	(a)
		2008	(a)	414	(a)
AIC ancillary services and	Purchased Power	**2010**	**(a)**	**2**	**(a)**
capacity agreements with UE		2009	(a)	3	(a)
		2008	(a)	13	(a)
Ancillary services agreement with	Purchased Power	**2010**	**(a)**	**-**	**(a)**
Marketing Company		2009	(a)	(b)	(a)
		2008	(a)	17	(a)
EEI power supply agreement with	Purchased Power	**2010**	**(a)**	**(a)**	**11**
Marketing Company		2009	(a)	(a)	42
		2008	(a)	(a)	56
Executory tolling agreement with Medina	Purchased Power	**2010**	**(a)**	**(a)**	**(a)**
Valley		2009	(a)	(c)	(a)
		2008	(a)	39	(a)
Total Purchased Power		**2010**	**$ (a)**	**$ 235**	**$ (a)**
		2009	(a)	403	(a)
		2008	(a)	483	(a)
Insurance recoveries	Operating Revenues and	**2010**	**$ -**	**$ (a)**	**$ -**
	Purchased Power	2009	-	(a)	-
		2008	-	(a)	(11)
Gas purchases from Genco	Gas Purchased for Resale	**2010**	**$ (a)**	**$ 1**	**$ (a)**
		2009	(a)	2	(a)
		2008	(a)	7	(a)
Ameren Services support services	Other Operations and	**2010**	**$ 124**	**$ 98**	**$ 23**
agreement	Maintenance	2009	126	99	27
		2008	130	161	28
AFS support services agreement	Other Operations and	**2010**	**7**	**(b)**	**3**
	Maintenance	2009	7	6	3
		2008	7	5	3
Insurance premiums(d)	Other Operations and	**2010**	**1**	**(a)**	**-**
	Maintenance	2009	2	(a)	1
		2008	8	(a)	5
Total Other Operations and		**2010**	**$ 132**	**$ 98**	**$ 26**
Maintenance Expenses		2009	135	105	31
		2008	145	166	36

Money pool borrowings (advances)	Interest (Charges)	**2010**	**$**	**-**	**$**	**(b)**	**$**	**(b)**
	Income	2009		-		(b)		(1)
		2008		-		(b)		(b)

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(a) Not applicable.
(b) Amount less than $1 million.
(c) In January 2009, CILCO transferred the tolling agreement to Marketing Company.
(d) Represents insurance premiums paid to Energy Risk Assurance Company, an affiliate for replacement power, property damage and terrorism coverage.

NOTE 15 COMMITMENTS AND CONTINGENCIES

We are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions, and governmental agencies with respect to matters that arise in the ordinary course of business, 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 a material adverse effect on our results of operations, financial position, or liquidity.

See also Note 1 Summary of Significant Accounting Policies, Note 2 Rate and Regulatory Matters, Note 10 Callaway Nuclear Plant and Note 14 Related Party Transactions in this report.

Callaway Nuclear Plant

The following table presents insurance coverage at UE s Callaway nuclear plant at December 31, 2010. The property coverage and the nuclear liability coverage have historically been renewed on October 1 and January 1, respectively, of each year. However, the property insurance carrier is moving the renewal date to April 1 starting in 2011.

Type and Source of Coverage	Maximum Coverages	Maximum Assessments for Single Incidents
Public liability and nuclear worker liability:		
American Nuclear Insurers	$ 375	$ -
Pool participation	12,219[(a)]	118[(b)]
	$ 12,594[(c)]	$ 118
Property damage:		
Nuclear Electric Insurance Ltd.	$ 2,750[(d)]	$ 23
Replacement power:		
Nuclear Electric Insurance Ltd	$ 490[(e)]	$ 9
Energy Risk Assurance Company	$ 64[(f)]	$ -

(a) Provided through mandatory participation in an industrywide retrospective premium assessment program.
(b) Retrospective premium under Price-Anderson Act. This is subject to retrospective assessment with respect to a covered loss in excess of $375 million in the event of an incident at any licensed U.S. commercial reactor, payable at $17.5 million per year.
(c) Limit of liability for each incident under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. A company could be assessed up to $118 million per incident for each licensed reactor it operates with a maximum of $17.5 million per incident to be paid per year for each reactor. This limit is subject to change to account for the effects of inflation and changes in the number of licensed reactors.
(d) Provides for $500 million in property damage and decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage.
(e) Provides the replacement power cost insurance in the event of a prolonged accidental outage at our nuclear plant. Weekly indemnity of $4.5 million for 52 weeks, which commences after the first eight weeks of an outage, plus $3.6 million per week for 71.1 weeks thereafter.
(f) Provides the replacement power cost insurance in the event of a prolonged accidental outage at our nuclear plant. The coverage commences after the first 52 weeks of insurance coverage from Nuclear Electric Insurance Ltd. and is for a weekly indemnity of $900,000 for 71 weeks in excess of the $3.6 million per week set forth above. Energy Risk Assurance Company is an affiliate and has reinsured this coverage with third-party insurance companies. See Note 14 Related Party Transactions for more information on this affiliate transaction.

The Price-Anderson Act is a federal law that limits the liability for claims from an incident involving any licensed United States commercial nuclear power facility. The limit is based on the number of licensed reactors. The limit of liability and the maximum potential annual payments are adjusted at least every five years for inflation to reflect changes in the Consumer Price Index. The five-year inflationary adjustment as prescribed by the most recent Price-Anderson Act renewal was effective October 29, 2008. Owners of a nuclear reactor cover this exposure through a combination of private insurance and mandatory participation in a financial protection pool, as established by the Price-Anderson Act.

After the terrorist attacks on September 11, 2001, Nuclear Electric Insurance Ltd. confirmed that losses resulting from terrorist attacks would be covered under its policies. However, Nuclear Electric Insurance Ltd. imposed an industrywide aggregate policy limit of $3.24 billion within a 12-month period for coverage for such terrorist acts.

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 unavailable, UE is at risk for any uninsured losses. If a serious nuclear incident were to occur, it could have a material adverse effect on Ameren s and UE s results of operations, financial position, or liquidity.

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Leases

The following table presents our lease obligations at December 31, 2010:

	Total	2011	2012	2013	2014	2015	After 5 Years
Ameren:[(a)]							
Capital lease payments[(b)]	$ 653	$ 32	$ 33	$ 32	$ 32	$ 33	$ 491
Less amount representing interest	339	27	28	27	27	27	203
Present value of minimum capital lease payments	314	5	5	5	5	6	288
Operating leases[(c)]	336	39	36	30	25	25	181
Total lease obligations	$ 650	$ 44	$ 41	$ 35	$ 30	$ 31	$ 469
UE:							
Capital lease payments[(b)]	$ 653	$ 32	$ 33	$ 32	$ 32	$ 33	$ 491
Less amount representing interest	339	27	28	27	27	27	203
Present value of minimum capital lease payments	314	5	5	5	5	6	288
Operating leases[(c)]	146	13	13	12	12	12	84
Total lease obligations	$ 460	$ 18	$ 18	$ 17	$ 17	$ 18	$ 372
AIC:							
Operating leases[(c)]	$ 7	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1
Genco:							
Operating leases[(c)]	$ 139	$ 11	$ 11	$ 11	$ 10	$ 10	$ 86

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) See Properties under Part I, Item 2, and Note 3 Property and Plant, Net of this report for additional information.
(c) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. Ameren s $2 million annual obligation for these items is included in the 2011 through 2015 columns. Amounts for After 5 Years are not included in the total because that period is indefinite.

We lease various facilities, office equipment, plant equipment, and rail cars under operating leases. The following table presents total rental expense, included in other operations and maintenance expenses, for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
Ameren[(a)]	$ **29**	$ 27	$ 19
UE	**19**	19	20
AIC	**19**	19	28
Genco	**3**	5	2

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

Other Obligations

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, nuclear fuel, and methane gas. We also have entered into various long-term commitments for purchased power and natural gas for distribution. The table below presents our estimated fuel, purchased power, and other commitments at December 31, 2010. Ameren s and UE s purchased power obligations include a 102-MW power purchase agreement with a wind farm operator that expires in 2014. Ameren s and AIC s purchased power obligations include the AIC power purchase agreements entered into as part of the IPA-administered power procurement process. Included in the Other column are minimum purchase commitments under contracts for equipment, design and construction, meter reading services, and an Ameren tax credit obligation at December 31, 2010. Ameren s tax credit obligation is a $33 million note payable issued for an investment in a commercial real estate development partnership to acquire tax credits. This note payable was netted against the related investment in Other Assets at December 31, 2010, as Ameren has a legally enforceable right to offset under authoritative accounting guidance.

	Coal	Natural Gas	Nuclear	Purchased Power	Methane Gas	Other	Total
Ameren:[(a)]							
2011	$ 1,030	$ 472	$ 76	$ 254	$ -	$ 145	$ 1,977
2012	809	381	37	87	1	118	1,433
2013	342	267	39	134	3	79	864
2014	170	187	112	53	3	70	595
2015	127	104	72	53	3	71	430
Thereafter	558	164	362	700	98	305	2,187
Total	$ 3,036	$ 1,575	$ 698	$ 1,281	$ 108	$ 788	$ 7,486
UE:							
2011	$ 513	$ 70	$ 76	$ 23	$ -	$ 69	$ 751
2012	367	53	37	23	1	54	535
2013	232	44	39	23	3	57	398
2014	156	34	112	23	3	47	375
2015	112	14	72	23	3	46	270
Thereafter	495	31	362	203	98	182	1,371
Total	$ 1,875	$ 246	$ 698	$ 318	$ 108	$ 455	$ 3,700
AIC:							
2011	$ -	$ 385	$ -	$ 231	$ -	$ 30	$ 646
2012	-	321	-	64	-	21	406
2013	-	221	-	111	-	22	354
2014	-	150	-	30	-	22	202
2015	-	88	-	30	-	24	142
Thereafter	-	133	-	497	-	124	754
Total	$ -	$ 1,298	$ -	$ 963	$ -	$ 243	$ 2,504
Genco:							
2011	$ 395	$ 10	$ -	$ -	$ -	$ 22	$ 427
2012	338	6	-	-	-	19	363
2013	65	3	-	-	-	-	68
2014	-	3	-	-	-	-	3
2015	-	2	-	-	-	-	2
Thereafter	-	-	-	-	-	-	-
Total	$ 798	$ 24	$ -	$ -	$ -	$ 41	$ 863

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

Also, as part of the 2007 Illinois Electric Settlement Agreement, AIC entered into financial contracts with Marketing Company to lock in energy prices for 400 to 1,000 megawatts annually of their round-the-clock power requirements from 2008 to 2012. These commitments are not reflected in the above table. See Note 7 Derivative Financial Instruments and Note 14 Related Party Transactions for additional information.

Environmental Matters

We are subject to various environmental laws and regulations enforced 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, natural gas storage facilities, and natural gas transmission and distribution facilities, our activities involve compliance with diverse environmental laws and regulations. These laws and regulations address emissions, impacts to air, land and water, noise, protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archeological and historical resources), and

chemical and waste handling. Complex and lengthy processes are required 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 release prevention plans and emergency response procedures.

In addition to existing laws and regulations governing our facilities, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren, UE and Genco, that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; revised ambient air quality standards for SO_2 and NO_x emissions increasing the stringency of the existing ozone ambient air quality standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is also expected to propose new regulations under the

Clean Water Act, that could require

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significant capital expenditures such as new water intake structures or cooling towers at our power plants; NSPS and emission guidelines for greenhouse gas emissions applicable to new and existing electric generating units; and a MACT standard for the control of hazardous air pollutants such as mercury and acid gases from power plants. Such new regulations may be challenged with lawsuits, so the timing of their ultimate implementation is uncertain. Although many details of these future regulations are unknown, the combined effects of the new and proposed environmental regulations may result in significant capital expenditures and/or increased operating costs over the next five to eight years for Ameren, UE and Genco. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. As a result, these regulations could require us to close or to significantly alter the operation of our generating facilities, which could have an adverse effect on our results of operations, financial position, and liquidity. Failure to comply with environmental laws and regulations may also result in the imposition of fines, penalties, and injunctive measures.

The estimates in the table below contain all of the known capital costs to comply with existing environmental regulations and our preliminary assessment of the potential impacts of the EPA s proposed regulations for coal combustion byproducts, the CATR, and the revised ambient air quality standards for SO_2 and NO_x emissions as of December 31, 2010. The estimates in the table below assume that coal combustion byproducts will ultimately be regarded as nonhazardous. The estimates shown in the table below could change depending upon additional federal or state requirements, regulation of greenhouse gas emissions, new hourly ambient air quality standards or changes to existing standards for SO_2 and NO_x emissions, the requirements under a MACT standard for the control of hazardous air pollutants such as mercury and acid gases, the requirements under the finalized CATR, any new regulations under the Clean Water Act, a hazardous classification of coal combustion byproducts, new technology, and variations in costs of material or labor, or alternative compliance strategies, among other factors.

	2011	2012 - 2015		2016 - 2020		Total	
UE[(a)]	$ 35	$ 850 -	$ 1,050	$ 1,380 -	$ 1,610	$ 2,265 -	$ 2,695
Genco	125	470 -	580	50 -	60	645 -	765
AERG	10	125 -	160	5 -	10	140 -	180
Ameren	$ 170	$ 1,445 -	$ 1,790	$ 1,435 -	$ 1,680	$ 3,050 -	$ 3,640

(a) UE s expenditures are expected to be recoverable from ratepayers.

The following sections describe the more significant environmental rules that affect our operations.

Clean Air Act

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. In March 2005, the EPA issued regulations with respect to SO_2 and NO_x emissions (the CAIR) and mercury emissions (the Clean Air Mercury Rule). The federal CAIR requires generating facilities in 28 states, including Missouri and Illinois, where our generating facilities are located, and the District of Columbia to participate in cap-and-trade programs to reduce annual SO_2 emissions, annual NO_x emissions, and ozone season NO_x emissions. The cap-and-trade program for both annual and ozone season NO_x emissions went into effect on January 1, 2009. The SO_2 emissions cap-and-trade program went into effect on January 1, 2010.

In February 2008, the U.S. Court of Appeals for the District of Columbia issued a decision that vacated the federal Clean Air Mercury Rule. The court ruled that the EPA erred in the method it used to remove electric generating facilities from the list of sources subject to the MACT requirements under the Clean Air Act. As a result, the EPA is currently developing a MACT standard for mercury emissions and other hazardous air pollutants, such as acid gases. In a consent order, the EPA agreed to propose the MACT regulation by the end of March 2011 and finalize the regulation by November 2011. Unless such deadlines are extended, compliance is expected to be required in 2015. We cannot predict at this time the capital or operating costs for compliance with such future environmental rules.

In December 2008, the U.S. Court of Appeals for the District of Columbia remanded the CAIR to the EPA for further action to remedy the rule s flaws, but allowed the CAIR s cap-and-trade programs to remain effective until they are replaced by the EPA. The impact of the decision is that the existing Illinois and Missouri rules to implement the federal CAIR will remain in effect until the federal CAIR is revised by the EPA, at which point the Illinois and Missouri rules may be subject to change. In July 2010, the EPA announced the CATR, which, when finalized, will replace CAIR. As proposed, the CATR will establish emission allowance budgets for each of the 31 states included in the regulation, including Missouri and Illinois and the District of Columbia. With the CATR, the EPA abandoned CAIR s regional approach to cutting emissions and instead set a pollution budget for each of the impacted states based on the EPA s analysis of each upwind state s contribution to air quality in downwind states. Emission reductions would be required in two phases beginning in 2012, with further reductions projected in 2014. The EPA estimates that by 2014, the CATR and other state and EPA actions would reduce the SO_2 emissions from power plants by 71% and their NO_x

emissions by 52% from 2005 levels. The proposed CATR is complex, as many issues relating to the establishment of state emission budgets, allowance allocations, and implementation are currently unclear. Our review of the proposed regulation is ongoing and, at this time, we cannot predict the estimated capital or operating expense for compliance with the CATR, assuming the CATR is adopted. The EPA expects the CATR to be finalized in the spring of 2011. Further, the EPA announced that additional NO_x emission reductions will be required to attain ozone standards. Therefore, the agency plans to propose an additional transport rule in 2011, to become final in 2012.

Separately, in January and June 2010, the EPA finalized a new ambient standard for SO_2 and NO_x and also announced plans for further reductions in the annual national ambient air quality standard for fine particulates. The state of Illinois and the state of Missouri will be required to individually develop attainment plans to comply with the ambient standards. We are unable to predict the future impact on these regulatory developments on our results of operations, financial position, and liquidity.

The state of Missouri adopted rules to implement the federal CAIR for regulating SO_2 and NO_x emissions from electric generating facilities. The rules are a significant part of Missouri s plan to attain existing ambient standards for ozone and fine particulates, and to meet the federal Clean Air Visibility Rule. The rules are expected to reduce NO_x and SO_2 emissions from electric generating facilities in Missouri by 30% and 75% respectively, by 2015. To comply with the Missouri rules, UE will use allowances and install pollution control equipment. In 2010, UE completed the installation of two scrubbers at its Sioux plant to reduce SO_2 emissions. UE s current compliance plan includes the installation of six scrubbers within its coal-fired fleet during the next ten years. Missouri also adopted rules to implement the federal Clean Air Mercury Rule. However, these rules are not enforceable as a result of the U.S. Court of Appeals decision to vacate the federal Clean Air Mercury Rule.

We do not believe that the court decision that vacated the federal Clean Air Mercury Rule will significantly affect pollution control obligations in Illinois in the near term. Under the MPS, as amended, Illinois generators may defer until 2015 the requirement to reduce mercury emissions by 90%, in exchange for accelerated installation of NO_x and SO_2 controls. This rule, when fully implemented, is expected to reduce mercury emissions by 90%, NO_x emissions by 50%, and SO_2 emissions by 70% by 2015 in Illinois. To comply with the rule, Genco and AERG are installing equipment designed to reduce mercury, NO_x, and SO_2 emissions. In 2009, AERG completed the installation of scrubbers at its Duck Creek plant. In 2010, Genco completed the installation of a scrubber at its Coffeen plant. Genco and AERG will also need to install additional pollution control equipment to meet these new emission reduction requirements as they become due. Current plans include installing scrubbers at Genco s Newton plant with completion expected in late 2013 and spring 2014. Additional plans include optimizing operations of selective catalytic reduction (SCR) systems for NO_x reduction at Genco s Coffeen plant and AERG s E.D. Edwards and Duck Creek plants. Genco is currently planning to use dry sorbent injection SO_2 reduction technology on all coal-fired units at

EEI s Joppa plant, but is also reviewing other options. Capital requirements for dry sorbent injection would be lower than for scrubbers. Several projects are planned to manage the solid and liquid wastes generated by the SO_2 scrubbers at the Duck Creek and Coffeen plants. Additional facilities and upgrades are planned at all Merchant Generation coal-fired plants to meet the 2015 mercury control requirements.

Emission Allowances

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. The Clean Air Act created marketable commodities called allowances under the Acid Rain Program, the NO_x Budget Trading Program, and the federal CAIR. Electric generating facilities have been allocated SO_2 and NO_x allowances based on past production and the statutory emission reduction goals. Our generating facilities comply with the SO_2 limits through the use and purchase of allowances, through the use of low-sulfur fuels, and through the application of pollution control technology. Our generating facilities comply with the NO_x limits through the use and purchase of allowances and through the application of pollution control technology, including low-NO_x burners, over-fire air systems, combustion optimization, rich-reagent injection, selective noncatalytic reduction, and selective catalytic reduction systems.

See Note 1 Summary of Significant Accounting Policies for the SO_2 and NO_x emission allowances held and the related SO_2 and NO_x emission allowance book values that were classified as intangible assets as of December 31, 2010.

Environmental regulations, including the CAIR and CATR, the timing of the installation of pollution control equipment, and the level of operations, will have a significant impact on the number of allowances actually required for ongoing operations. The CAIR requires a reduction in SO_2 emissions by increasing the ratio of Acid Rain Program allowances surrendered. The CATR, which the EPA proposed to replace the CAIR, however, does not rely upon the Acid Rain Program for its allowance allocation program. In previous periods, Ameren, UE and Genco expected to use their SO_2 allowances for ongoing operations. However, the proposed CATR would restrict the use of existing SO_2 allowances for achieving compliance with SO_2 emission limitations. Ameren, UE and Genco no longer expect all of their SO_2 allowances will be used in operations. Therefore, in 2010, Ameren, UE and Genco recorded a noncash impairment charge to reduce the carrying value of their SO_2 emission allowances to their estimated fair value. UE s impairment had no impact on earnings as UE recorded the impairment by reducing a previously established regulatory liability related to SO_2 allowances. See Note 17 Goodwill and Other Asset Impairments for additional information about the emission allowance impairment.

The CAIR has both an ozone season program and an annual program for regulating NO_x emissions, with separate

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allowances issued for each program. The CAIR will remain in effect until it is replaced by the CATR, which is expected to become effective in 2012. The following table presents the ozone season and annual NO_x allowances, in tons, granted to our generating facilities in Missouri and Illinois.

	Missouri[a]		Illinois[b]		
	Ozone	Annual	Ozone	Annual	Total
UE	11,665	26,842	90	93	38,690
Genco	1	3	5,200	12,867	18,071
AERG	(c)	(c)	1,368	3,419	4,787
Ameren total	11,666	26,845	6,658	16,379	61,548

(a) Allowances granted annually for the years 2009 through 2014.
(b) Allowances granted annually for the years 2010 and 2011.
(c) Not applicable.

Global Climate Change

Initiatives to limit greenhouse gas emissions and to address climate change have been subject to consideration in the U.S. Congress. In the past two years, legislation has been passed in the U.S. House of Representatives and proposed in the Senate to reduce greenhouse gas emissions from designated sources, including coal-fired electric generation units. Many of these proposals have included economy-wide cap-and-trade programs. The reduction of greenhouse gas emissions has been identified as a high priority by President Obama s administration.

Potential impacts from climate change legislation could vary, depending upon proposed CO_2 emission limits, the timing of implementation of those limits, the method of distributing any allowances, the degree to which offsets are allowed and available, and provisions for cost-containment measures, such as a safety valve provision that provides a maximum price for emission allowances. As a result of our diverse fuel portfolio, our emissions of greenhouse gases vary among our generating facilities, but coal-fired power plants are significant sources of CO_2. Ameren s analysis shows that if most versions of the recently proposed climate change bills were enacted into law, household costs and rates for electricity could rise significantly. The burden could fall particularly hard on electricity consumers and upon the economy in the Midwest because of the region s reliance on electricity generated by coal-fired power plants. Natural gas emits per kilowatthour about half as much CO_2 as coal emits when burned to produce electricity. Therefore, climate change regulation could cause the conversion of coal-fired power plants to natural gas, or the construction of new natural gas plants to replace coal-fired power plants. As a result, economywide shifts to natural gas as a fuel source for electricity generation also could affect the cost of heating for our utility customers and many industrial processes that use natural gas. Higher costs for energy could contribute to reduced demand for electricity and natural gas.

In December 2009, the EPA issued its endangerment finding determining that greenhouse gas emissions, including CO_2, endanger human health and welfare and that

emissions of greenhouse gases from motor vehicles contribute to that endangerment. In March 2010, the EPA issued a determination that greenhouse gas emissions from stationary sources, such as power plants, would be subject to regulation under the Clean Air Act in 2011. As a result of these actions, we are required to consider the emissions of greenhouse gas in any air permit application.

Recognizing the difficulties presented by regulating at once virtually all emitters of greenhouse gases, the EPA finalized in May 2010 regulations known as the Tailoring Rule, that would establish new higher thresholds for regulating greenhouse gas emissions from stationary sources, such as power plants. The Tailoring Rule became effective in January 2011. The rule requires any source that already has an operating permit to have greenhouse gas-specific provisions added to their permits upon renewal. Currently, all Ameren power plants have operating permits that, when renewed, may be modified to address greenhouse gas emissions. The Tailoring Rule also provides that if projects performed at major sources result in an increase in emissions of greenhouse gases of at least 75,000 tons per year, measured in CO_2 equivalents, such projects could trigger permitting requirements under the NSR/Prevention of Significant Deterioration program and the application of best available control technology, if any, to control greenhouse gas emissions. New major sources also would be required to obtain such a permit and to install the best available control technology if their greenhouse gas emissions exceed the applicable emissions threshold. Separately, in December 2010, the EPA announced it would establish NSPS for greenhouse gas emissions at new and existing fossil-fuel fired power plants. In the announcement, the EPA said it will propose standards for power plants in July 2011 and issue final standards in May 2012. It is uncertain whether reductions to greenhouse gas emissions would be required at our power plants as a result of any of the EPA s new and future rules. Legal challenges to the EPA s greenhouse gas rules have been filed and more challenges are expected. Any federal climate change legislation that is enacted may preempt the EPA s regulation of greenhouse gas emissions, including the Tailoring Rule, particularly as it relates to power plant greenhouse gas emissions. The extent to which the Tailoring Rule could have a material impact on our generating facilities depends upon how state agencies apply the EPA s guidelines as to what constitutes the best available control technology for greenhouse gas emissions from power plants, whether physical changes or changes in operations subject to the rule occur at our power plants, and whether federal legislation that preempts the rule is passed.

Although the EPA has stated its intention to regulate greenhouse gas emissions from stationary sources, such as power plants, congressional action could block or delay that effort. In 2010, legislation was introduced in both the U.S. House of Representatives and U.S. Senate that would block the EPA from regulating greenhouse gas emissions from both mobile and stationary sources. Separate legislation has also been introduced in both the U.S. House of

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Representatives and U.S. Senate that would delay the EPA s ability to regulate greenhouse gas emissions from stationary sources for two years. The final outcome of such proposed legislation is uncertain.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would likely result in significant increases in capital expenditures and operating costs, which, in turn, could lead