THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Central Illinois Light Company	End of 2009/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Central Illinois Light Company	02 Year/Period of Report End of 2009/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 300 Liberty Street, Peoria, IL 61602	
05 Name of Contact Person Theresa Nistendirk	06 Title of Contact Person Manager, External Reporting
07 Address of Contact Person *(Street, City, State, Zip Code)* 1901 Chouteau Avenue, St. Louis, MO 63103	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(314) 206-0693	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Michael Getz	Michael Getz	04/19/2010
02 Title Controller, Ameren IL Utilities		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	None
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	None
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	None
63	Hydroelectric Generating Plant Statistics	406-407	None
64	Pumped Storage Generating Plant Statistics	408-409	None
65	Generating Plant Statistics Pages	410-411	None
66	Transmission Line Statistics Pages	422-423	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	None
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
1901 Chouteau Avenue
St. Louis, MO 63103

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Illinois - April 11, 1913

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric and gas utility services in Illinois.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficieARIES for whom trust was maintained, and purpose of the trust.

As of December 31, 2009, CILCORP Inc., a holding company, owned all of the outstanding common stock of the Respondent, and Ameren Corporation owned all of the outstanding common stock of CILCORP Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	AmerenEnergy Resources Generating Company	Corporation owns and operates	100	
2	formerly known as Central Illinois Generation	most of Central Illinois		
3	Inc.	Light Company's electric		
4		generation assets. Assets		
5		were transferred on		
6		October 3, 2003. Authorized		
7		by Illinois Commerce		
8		Commission Docket #02-0152,		
9		dated February 13, 2002 and		
10		approved April 10, 2002.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman, President and Chief Executive Officer	Scott A. Cisel	387,000
2	Senior Vice President	Daniel F. Cole	370,267
3	Senior VP and Chief Financial Officer (1/1/09-4/30/09)	Warner L. Baxter	186,267
4	Senior Vice President and Chief Financial Officer	Martin J. Lyons, Jr.	364,867
5	Senior Vice President, General Counsel and Secretary	Steven R. Sullivan	417,133
6	Vice President and Treasurer	Jerre E. Birdsong	297,200
7	Vice President (Senior VP effective 12/16/2009)	Craig D. Nelson	242,100
8	Senior Vice President	Gregory L. Nelson	304,100
9	Vice President	Stan E. Ogden	172,500
10	Vice President	Ronald D. Pate	190,192
11	Vice President (1/1/09-11/30/09)	William J. Prebil	181,317
12	Vice President	Dennis W. Weisenborn	206,200
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Warner L. Baxter, Executive Vice President & CFO *** (1)	1901 Chouteau Avenue, St. Louis, MO 63103
2		
3	Scott A. Cisel, Chairman, President & CEO ***	300 Liberty Street, Peoria IL 61602
4		
5	Daniel F. Cole, Senior Vice President	1901 Chouteau Avenue, St. Louis, MO 63103
6		
7	Martin J. Lyons, Senior Vice President & CFO*** (2)	1901 Chouteau Avenue, St. Louis, MO 63103
8		
9	Steven R. Sullivan, Sr. Vice President, Gen. Counsel	1901 Chouteau Avenue, St. Louis, MO 63103
10	& Sec. ***	
11		
12		
13	(1) Relinquished title as officer and director effective	
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16	(2) Elected effective 5/1/09	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midwest ISO FERC Electric Tariff Original Volume 1	ER98-1438
2	Midwest ISO FERC Electric Tariff First Revised Vo1	ER98-1438
3	Midwest ISO FERC Electric Tariff Second Revised V1	ER04-458
4	Midwest ISO FERC Electric Tariff Second Revised V1	ER04-895
5	Midwest ISO FERC Electric Tariff Second Revised V1	ER05-122
6	Midwest ISO FERC Electric Tariff Third Revised Vo1	ER05-1085; ER04-458
7	Midwest ISO FERC Electric Tariff Third Revised Vo1	ER04-691; EL04-104
8	Midwest ISO FERC Electric Tariff Third Revised Vo1	ER06-159
9	Midwest ISO FERC Electric Tariff Third Revised Vo1	ER07-113
10	Midwest ISO FERC Electric Tariff Fourth Revised V1	OA08-4
11	Midwest ISO FERC Electric Tariff Fourth Revised V1	ER09-15
12	Midwest ISO FERC Electric Tariff Third Revised Vo1	ER09-91
13	Midwest ISO FERC Electric Tariff Fourth Revised V1	ER09-91; ER09-571
14	Midwest ISO FERC Electric Tariff Fourth Revised V1	ER09-1657
15	Midwest ISO FERC Electric Tariff Fourth Revised V1	ER09-1779
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	All	Amounts are the sum of CILCO, CIPS & IP		
2	401	Monthly Peaks and Outputs	d	
3	328	Transmission of Electricity for Others	n	
4	214	Electric Plant Held for Future Use	d	2
5	227	Material and Supplies	c	16
6	323	Electric Operation and Maintenance Expenses	b	182
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Schedule Page: 1062 Line No.: 1 Column:

Central Illinois Public Service Company (CIPS), Central Illinois Light Company (CILCO), and Illinois Power Company (IPC), collectively known as Ameren Illinois Utilities (AMIL), is a transmission owner in the Midwest Independent System Operator (MISO). AMIL files an Attachment O with MISO, as such all amounts represent the sum of CILCO, CIPS, and IPC. Lines 2-5 show where data included in Attachment O related to CIPS differ from the data in this form.

Schedule Page: 1062 Line No.: 2 Column:

Page 401b, column (d) only reflects the highest monthly demand for retail load supplied by Central Illinois Light Company (CILCO). It exlcudes retail load served by Retail Electric Suppliers under seperate NITS agreements. Page 1, line 8 of the Ameren Illinois Utilities (AMIL) Attachment O reflects the entire retail load served by all three Ameren utilities under a single NITS agreement coincident with the Ameren Illinois monthly system peaks. Page 1, line 10 of the AMIL Attachment O reflects the remaining retail and wholesale load served under other NITS agreements. This is consistent with how Schedule 9 is billed.

Schedule Page: 1062 Line No.: 3 Column:

Ameren reports data from page 328 column (l) lines 35 and 36 on page 4 of the Attachment O. Total revenue reported on page 328 column (n) includes Column (m), other revenue, which as shown in the footnote includes Schedule 1 revenue from MISO as well as distribution rental charges paid by wholesale NITS customers. These charges should not be a credit to the transmission revenue requirement. The data in page 328 column (l), energy charges, contains all transmission revenues under Schedules 7, 8, 9 and 26.

Schedule Page: 1062 Line No.: 4 Column:

Transmission total includes some properties less than $250,000 not seperately listed.

Schedule Page: 1062 Line No.: 5 Column:

Stores Expenses related to transmission is not listed on page 227.

Schedule Page: 1062 Line No.: 6 Column:

Ameren reports data from page 323 column (b) line 182 in the Attachment O. Total expenses reported on page 323 column (b) includes support service expenses related to the Ameren Illinois Utilities Services Agreement. These expenses should not be included in the Attachment O.

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None

2. None

3. None

4. None

5. None

6. See Note 4 – Credit Facility Borrowings and Liquidity, and Note 5 – Long-Term Debt and Equity Financings and Note 14 – Related Party Transactions in the "Notes to Financial Statement." On June 30, 2009, the 2006 Credit Agreement in Docket No. 06-0330 and the 2007 Credit Agreement in Docket No. 07-0124)when taken together equaled $150,000,000) were terminated, and the 2006 Credit Agreement Series and the 2007 Credit Agreement Series securing the Company's obligations, were redeemed. Simultaneously on June 30, 2009, the Company entered into a new credit agreement ($150,000,000) and issued a new series of First Mortgage Bonds to secure its obligations thereunder in accordance with authority granted by the Illinois Commerce Commission Order on June 24, 2009, in Docket No. 09-0275.

7. None

8. Local 51 Bargaining Unit Personnel during the third quarter of 2009, specifically beginning July 1st, were granted a 3% wage increase. The current estimated annual cost effect of this increase amounts to approximately $665,738 using total wages for 2008 as a base. This labor group comprises 277 employees.

9. See Note 2 – Rate and Regulatory Matters and Note 15 – Commitments and Contingencies in the "Notes to Financial Statement."

10. None

11. (Reserved)

12. None

13. Effective February 1, 2009, Bruce A. Steinke relinquished his position as Vice President and Controller.
    Effective February 1, 2009, Michael J. Getz was elected Controller.
    Effective May 1, 2009, Warner Baxter relinquished his positions of Executive Vice President and Chief Financial Officer.
    Effective May 1, 2009, Martin J. Lyons, Jr. was elected Senior Vice President and Chief Financial Officer and Director.
    Effective December 1, 2009, Scott A. Glaeser was elected Vice President.
    Effective December 1, 2009, William J. Prebil retired as Vice President.
    Effective December 16, 2009 Craig D. Nelson was elected Senior Vice President.

14. Not applicable.

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Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,505,957,795	1,458,186,249
3	Construction Work in Progress (107)	200-201	11,521,503	12,207,611
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,517,479,298	1,470,393,860
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	928,765,509	914,934,143
6	Net Utility Plant (Enter Total of line 4 less 5)		588,713,789	555,459,717
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		588,713,789	555,459,717
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		1,502,184	1,502,184
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,868,394	2,827,873
19	(Less) Accum. Prov. for Depr. and Amort. (122)		32,819	8,745
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	550,993,189	437,492,201
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		7,614,013	8,419,182
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		925,462	20,196,456
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		1,202,438	1
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		563,570,677	468,926,968
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		170,084	135,655
36	Special Deposits (132-134)		1,500,000	1,500,000
37	Working Fund (135)		1,200	1,200
38	Temporary Cash Investments (136)		87,435,646	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		32,926,556	62,125,867
41	Other Accounts Receivable (143)		1,686,885	944,335
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,859,578	2,626,455
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		15,522,636	581,280
45	Fuel Stock (151)	227	0	34,614
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	7,528,848	7,563,043
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	396,865	327,844
55	Gas Stored Underground - Current (164.1)		44,695,116	74,875,525
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		14,277,428	547,117
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1	1
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		43,200,000	64,534,000
62	Miscellaneous Current and Accrued Assets (174)		2,170,740	58,422
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		3,041,317	-5
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		1,202,438	1
67	Total Current and Accrued Assets (Lines 34 through 66)		250,491,306	210,602,442
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,119,725	2,527,076
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	184,140,710	157,154,002
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	520
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	2,267,069	14,213,753
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		4,527,208	4,883,500
82	Accumulated Deferred Income Taxes (190)	234	54,933,851	52,854,177
83	Unrecovered Purchased Gas Costs (191)		397,281	0
84	Total Deferred Debits (lines 69 through 83)		248,385,844	231,633,028
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,652,663,800	1,468,124,339

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	end of 2009/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	185,661,496	185,661,496
3	Preferred Stock Issued (204)	250-251	19,120,400	19,120,400
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	294,167,330	243,167,330
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	83,305,986	83,576,180
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	270,490,782	156,989,794
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		852,745,994	688,515,200
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	279,000,000	279,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		332,436	360,384
24	Total Long-Term Debt (lines 18 through 23)		278,667,564	278,639,616
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		4,547,806	6,597,323
29	Accumulated Provision for Pensions and Benefits (228.3)		825,000	825,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		20,960,250	19,327,942
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		57,282,373	30,020,547
34	Asset Retirement Obligations (230)		976,223	20,270,614
35	Total Other Noncurrent Liabilities (lines 26 through 34)		84,591,652	77,041,426
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		38,928,442	41,630,063
39	Notes Payable to Associated Companies (233)		0	200,000
40	Accounts Payable to Associated Companies (234)		29,729,251	42,160,749
41	Customer Deposits (235)		8,289,031	7,470,136
42	Taxes Accrued (236)	262-263	2,571,910	10,610,112
43	Interest Accrued (237)		5,841,754	6,689,845
44	Dividends Declared (238)		217,902	217,902
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		596,404	585,380
48	Miscellaneous Current and Accrued Liabilities (242)		15,600,166	6,506,110
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	4,998,810
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		84,199,650	53,999,498
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		57,282,373	30,020,547
54	Total Current and Accrued Liabilities (lines 37 through 53)		128,692,137	145,048,058
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		11,431,226	11,182,897
57	Accumulated Deferred Investment Tax Credits (255)	266-267	2,736,148	3,332,525
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	185,132,850	208,274,062
60	Other Regulatory Liabilities (254)	278	12,085,812	-12,893,997
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		94,190,963	79,807,518
64	Accum. Deferred Income Taxes-Other (283)		2,389,454	-10,822,966
65	Total Deferred Credits (lines 56 through 64)		307,966,453	278,880,039
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,652,663,800	1,468,124,339

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	656,293,738	793,425,396		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	522,678,775	651,165,241		
5	Maintenance Expenses (402)	320-323	23,435,663	28,051,973		
6	Depreciation Expense (403)	336-337	30,980,236	48,466,969		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	15,639	19,391		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		27,228	6,797		
13	(Less) Regulatory Credits (407.4)		4,103,000			
14	Taxes Other Than Income Taxes (408.1)	262-263	23,871,006	21,765,234		
15	Income Taxes - Federal (409.1)	262-263	-12,647,079	6,826,459		
16	- Other (409.1)	262-263	785,398	2,385,450		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	50,508,275	15,166,013		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	29,575,554	18,351,288		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		957,237	1,143,582		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		606,933,824	756,645,821		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		49,359,914	36,779,575		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
379,676,155	417,033,931	276,617,583	376,391,465			2
						3
291,909,488	330,540,786	230,769,287	320,624,455			4
17,261,497	21,180,854	6,174,166	6,871,119			5
23,891,249	30,535,637	7,088,987	17,931,332			6
						7
5,331	9,083	10,308	10,308			8
						9
						10
						11
27,228	6,797					12
833,000		3,270,000				13
11,935,013	9,179,964	11,935,993	12,585,270			14
-11,912,801	842,351	-734,278	5,984,108			15
234,292	648,222	551,106	1,737,228			16
34,886,059	7,804,676	15,622,216	7,361,337			17
21,162,523	8,856,501	8,413,031	9,494,787			18
						19
						20
						21
						22
						23
957,237	1,143,582					24
347,199,070	393,035,451	259,734,754	363,610,370			25
32,477,085	23,998,480	16,882,829	12,781,095			26

Name of Respondent Central Illinois Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/19/2010	Year/Period of Report End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		49,359,914	36,779,575		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		193,592	313,662		
34	(Less) Expenses of Nonutility Operations (417.1)		31,260	51,393		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	113,500,988	52,594,611		
37	Interest and Dividend Income (419)		458,309	813,272		
38	Allowance for Other Funds Used During Construction (419.1)		365,242	-27,111		
39	Miscellaneous Nonoperating Income (421)		191,526	15,572,702		
40	Gain on Disposition of Property (421.1)		-115,066	3,396		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		114,563,331	69,219,139		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-32,041	9,546		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,001,712	565,773		
46	Life Insurance (426.2)		3,209,636	1,747,008		
47	Penalties (426.3)		48,749	20,067		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		645,640	767,716		
49	Other Deductions (426.5)		566,397	17,749,576		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,440,093	20,859,686		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	-1,574,020	-1,437,972		
54	Income Taxes-Other (409.2)	262-263	-354,168	-323,532		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,915,706	4,414,117		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	434,796	2,663,678		
57	Investment Tax Credit Adj.-Net (411.5)		-596,377	-685,616		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,043,655	-696,681		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		109,166,893	49,056,134		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		21,424,500	9,309,043		
63	Amort. of Debt Disc. and Expense (428)		511,759	416,058		
64	Amortization of Loss on Reaquired Debt (428.1)		356,292	348,899		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		1,290,303	6,151,098		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		158,451	27,734		
70	Net Interest Charges (Total of lines 62 thru 69)		23,424,403	16,197,364		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		135,102,404	69,638,345		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		135,102,404	69,638,345		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		83,576,180	67,637,222
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Redemption of Preferred Stock			(33,000)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(33,000)
16	Balance Transferred from Income (Account 433 less Account 418.1)		21,601,416	17,043,734
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	See footnote		-871,610	(1,354,235)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-871,610	(1,354,235)
30	Dividends Declared-Common Stock (Account 438)			
31			-21,000,000	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-21,000,000	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			282,459
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		83,305,986	83,576,180
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		83,305,986	83,576,180
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		156,989,794	104,677,642
50	Equity in Earnings for Year (Credit) (Account 418.1)		113,500,988	52,594,611
51	(Less) Dividends Received (Debit)			
52	Transfer to Account 216			(282,459)
53	Balance-End of Year (Total lines 49 thru 52)		270,490,782	156,989,794

Schedule Page: 118 Line No.: 24 Column: a

Total Dividends declared – Preferred Stock (Account 437) Footnote details

	Current YTD Amount	Prior YTD Amount
4.50% Series	500,688	500,688
4.64% Series	370,922	370,922
5.85% Series	-	482,625
	871,610	1,354,235

Schedule Page: 118 Line No.: 52 Column: d

Adjustment is related to the transfer of former subsidiary Retained Earnings from account 216.1 to account 216 as a result of the Legal Entity Reorganization that occured in 2008 per FERC Order AC07-161.

Name of Respondent Central Illinois Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/19/2010	Year/Period of Report End of 2009/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	135,102,404	69,638,345
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	31,953,112	49,629,942
5	Amortization of Debt Issue Costs	868,051	764,957
6	Net mark-to-market (gain) loss on derivatives	-5,795,385	5,728,583
7			
8	Deferred Income Taxes (Net)	22,413,631	-1,434,836
9	Investment Tax Credit Adjustment (Net)	-596,377	-685,616
10	Net (Increase) Decrease in Receivables	35,082,528	-5,413,182
11	Net (Increase) Decrease in Inventory	30,249,218	-23,173,333
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-19,988,382	30,225,706
14	Net (Increase) Decrease in Other Regulatory Assets	-3,675,966	-590,354
15	Net Increase (Decrease) in Other Regulatory Liabilities	188,000	
16	(Less) Allowance for Other Funds Used During Construction	365,242	-27,111
17	(Less) Undistributed Earnings from Subsidiary Companies	113,500,988	52,594,611
18	Other (provide details in footnote):		
19	Net (Increase) Decrease in Assets, Other	10,127,305	-16,567,486
20	Net (Increase) Decrease in Liabilities, Other	-3,610,458	3,518,089
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	118,451,451	59,073,315
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-61,475,008	-61,718,222
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-365,242	27,111
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-61,109,766	-61,745,333
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-61,109,766	-61,745,333
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		149,995,500
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Debt Issuance Costs		-900,000
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Capital contribution received	51,000,000	
69	Generator advances received for construction, net	1,200,000	1,697,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	52,200,000	150,792,500
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-19,200,000
74	Preferred Stock		-16,500,000
75	Common Stock		
76	Other (provide details in footnote):		
77	Contributions and Advances from Associate and Subsidiary Companies	-200,000	200,000
78	Net Decrease in Short-Term Debt (c)		-115,000,000
79			
80	Dividends on Preferred Stock	-871,610	-1,354,235
81	Dividends on Common Stock	-21,000,000	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	30,128,390	-1,061,735
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	87,470,075	-3,733,753
87			
88	Cash and Cash Equivalents at Beginning of Period	136,855	3,870,608
89			
90	Cash and Cash Equivalents at End of period	87,606,930	136,855

Schedule Page: 120   Line No.: 20   Column: c

During 2009, we concluded that generator advances received related to transmission upgrades should be classified in the financing activities on the cash flow statement. The 2008 balances have been reclassified for comparability.

Schedule Page: 120   Line No.: 69   Column: c

During 2009, we concluded that generator advances received related to transmission upgrades should be classified in the financing activities on the cash flow statement. The 2008 balances have been reclassified for comparability.

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

AMEREN CORPORATION (Consolidated)
UNION ELECTRIC COMPANY (Consolidated)
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
AMEREN ENERGY GENERATING COMPANY (Consolidated)
CENTRAL ILLINOIS LIGHT COMPANY (Consolidated)
ILLINOIS POWER COMPANY (Consolidated)

COMBINED NOTES TO FINANCIAL STATEMENTS
December 31, 2009

(These notes relate to all of the Ameren SEC registrants, including the FERC Form 1 respondent Central Illinois Light Company.)

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Illinois Commerce Commission (ICC), the Missouri Public Service Commission (MoPSC), the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA). The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts (USOA) and accounting releases, which require certain differences from accounting principles generally accepted in the United States (GAAP).

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, also known as AmerenUE, 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 located 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 126,000 customers.
- CIPS, or Central Illinois Public Service Company, also known as AmerenCIPS, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. CIPS was incorporated in Illinois in 1923 and is successor to a number of companies, the oldest of which was organized in 1902. It supplies electric and natural gas utility service to portions of central, west central and southern Illinois having an estimated population of 1.1 million in an area of 20,500 square miles. CIPS supplies electric service to 383,000 customers and natural gas service to 182,000 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, and natural gas and oil-fired electric generating facilities, are expected to have capacity of 3,454, 1,578, and 169 megawatts, respectively, at the time of the 2010 peak summer electrical demand.
- CILCO, or Central Illinois Light Company, also known as AmerenCILCO, operates a rate-regulated electric transmission and distribution business, a merchant electric generation business (through its subsidiary AERG), and a rate-regulated natural gas transmission and distribution business, all in Illinois. CILCO was incorporated in Illinois in 1913. It supplies electric and natural gas utility service to portions of central and east central Illinois in areas of 3,700 and 4,500 square miles, respectively, with an estimated population of 0.6 million. CILCO supplies electric service to 211,000 customers and natural gas service to 214,000 customers. AERG, a wholly owned subsidiary of CILCO, is expected to have capacity of 1,125 megawatts from its coal-fired electric generating facilities at the time of the 2010 peak summer electrical demand.
- IP, or Illinois Power Company, also known as AmerenIP, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. IP was incorporated in 1923 in Illinois. It supplies electric and natural gas utility service to portions of central, east central,

and southern Illinois, serving a population of 1.5 million in an area of 15,000 square miles, contiguous to our other service territories. IP supplies electric service to 617,000 customers and natural gas service to 417,000 customers, including most of the Illinois portion of the Greater St. Louis area.

Ameren has various other subsidiaries responsible for the short- and long-term marketing of power, procurement of fuel, 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. Ameren consolidates EEI for financial reporting purposes. 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. On 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. See Note 14 - Related Party Transactions for additional information.

The following table presents summarized financial information of EEI (in millions):

For the years ended December 31,	2009	2008	2007
Operating revenues	**$ 303**	$ 520	$ 427
Operating income	**19**	226	216
Net income	**10**	142	136
As of December 31,	**2009**	**2008**	**2007**
Current assets	**$ 86**	$ 76	$ 69
Noncurrent assets	**172**	140	124
Current liabilities	**165**	93	60
Noncurrent liabilities	**48**	43	10

The financial statements of Ameren, Genco and CILCO are prepared on a consolidated basis. CIPS has no subsidiaries and therefore is not consolidated. UE had a subsidiary in 2007 (Union Electric Development Corporation), but in January 2008 this subsidiary was transferred to Ameren in the form of a stock dividend. Accordingly, UE's financial statements were prepared on a consolidated basis for 2007 only. IP had a subsidiary in 2007 (Illinois Gas Supply Company) that was dissolved at December 31, 2007. Accordingly, IP's financial statements were prepared on a consolidated basis for 2007 only. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

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 management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates.

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, CIPS, CILCO and IP defer certain costs as assets pursuant to actions of our rate regulators or the expected ability to recover such costs in rates charged to customers. UE, CIPS, CILCO and IP also defer certain amounts as liabilities pursuant to actions of 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. Assets 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. See Note 2 - Rate and Regulatory Matters for additional information regarding regulatory recovery of uncollectible accounts receivable by the Ameren Illinois Utilities.

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, 2009 and 2008:

	Ameren[a]	UE	CIPS	Genco	CILCO	IP
2009:						
Fuel[b]	**$ 315**	**$ 154**	**$ -**	**$ 97**	**$ 38**	**$ -**
Gas stored underground	**183**	**22**	**32**	**-**	**45**	**84**
Other materials and supplies	**284**	**170**	**15**	**35**	**24**	**28**
	$ 782	**$ 346**	**$ 47**	**$ 132**	**$ 107**	**$ 112**
2008:						
Fuel[b]	$ 290	$ 139	$ -	$ 92	$ 32	$ -
Gas stored underground	277	32	54	-	75	117
Other materials and supplies	275	168	16	30	24	27
	$ 842	$ 339	$ 70	$ 122	$ 131	$ 144

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Consists of coal, oil, paint, propane, and tire chips.

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 2009, 2008 and 2007 generally 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 2009, 2008, and 2007:

	2009	2008	2007
Ameren	**6% - 10%**	1% - 7%	6% - 7%

UE	**6**	7	6
CIPS	**6**	1	6
CILCO	**10**	1	7
IP	**9**	5	6

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. Ameren's goodwill relates to its acquisition of IP and an additional 20% EEI ownership interest acquired in 2004 as well as its acquisition of CILCORP and Medina Valley in 2003. IP's goodwill relates to the acquisition of IP in 2004. See Note 17 - Goodwill 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, Genco's and CILCO's intangible assets at December 31, 2009 and 2008, consisted of emission allowances. 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 carried as intangible assets as of December 31, 2009. 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)	3,028,000	25,091	$ 129(e)
UE	1,610,000	13,677	35
Genco	743,000	9,258	34
CILCO (AERG)	354,000	210	1
EEI	321,000	1,946	5

(a) Vintages are from 2009 to 2019. Each company possesses additional allowances for use in periods beyond 2019.
(b) Vintage is 2009.
(c) The book value represents SO_2 and NO_x emission allowances for use in periods through 2039. The book value at December 31, 2008, for Ameren, UE, Genco, CILCO (AERG), and EEI was $167 million, $48 million, $49 million, $1 million, and $9 million, respectively.
(d) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(e) Includes $30 million and $24 million of fair-market value adjustments recorded in connection with Ameren's 2003 acquisition of CILCORP and Ameren's 2004 acquisition of an additional 20% ownership interest in EEI, respectively.

The following table presents amortization expense recorded in connection with the usage of emission allowances, net of gains from emission allowance sales, for Ameren, UE, Genco and CILCO (AERG) during the years ended December 31, 2009, 2008, and 2007**:**

	2009	2008	2007
Ameren(a)(b)	**$ 24**	$ 28	$ 35
UE	**(5)**	(5)	(5)
Genco	**16**	25	30
CILCO (AERG)	**2**	(c)	1

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Includes allowances consumed that were recorded through purchase accounting.
(c) 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. In 2009, Genco recorded asset impairment charges of $6 million as a result 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 as of December 31, 2009. The charge related to the office building was based on the expected net proceeds to be generated from its sale in 2010. In addition, CILCO recorded an asset impairment charge of $1 million to adjust the carrying value of CILCO's (AERG's) Indian Trails generation facility's estimated fair value as of December 31, 2009. This charge was based on the net proceeds generated from the sale of the facility in January 2010.

In 2008, asset impairment charges were recorded to adjust the carrying value of CILCO's (AERG's) Indian Trails and Sterling Avenue generation facilities to their estimated fair values as of December 31, 2008. CILCO recorded an asset impairment charge of $12 million related to the Indian Trails generation facility as a result of the suspension of operations by the facility's only customer. CILCORP recorded a $2 million impairment charge related to the Sterling Avenue CT. The charge was based on the net proceeds generated from the sale of the facility in 2009.

The 2009 and 2008 asset impairment charges were recorded in Operating Expenses - Other Operations and Maintenance Expense in the applicable statements of income and were included in Merchant Generation segment results.

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. Estimated environmental expenditures are regularly reviewed and updated. 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, CIPS, Genco, CILCO and IP 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.

In UE's, CIPS', CILCO's, and IP'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 and included in Other Current Assets or Other Current Liabilities on the balance sheet of Ameren and in Current Regulatory Assets or

Current Regulatory Liabilities on the balance sheet of UE, CIPS, CILCO and IP. The deferred amounts are either billed or refunded to natural gas utility customers in a subsequent period.

In the Ameren Illinois Utilities' 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 and included in Other Current Assets or Other Current Liabilities on the balance sheet of Ameren and in Current Regulatory Assets or Current Regulatory Liabilities on the balance sheets of CIPS, CILCO and IP. The deferred amounts are either billed or refunded to electric utility customers in a subsequent period.

In 2009, UE implemented a FAC for its retail electric jurisdiction. The FAC 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 difference between the costs of fuel incurred and the cost of fuel recovered from UE's customers are deferred and included in Other Current Assets or Other Current Liabilities on the balance sheet of Ameren and in Current Regulatory Assets or Current Regulatory Liabilities on the balance sheet of UE. 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, CIPS, CILCO and IP 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, CIPS, CILCO and IP recognize expenses associated with resettlements once the resettlement is probable and the resettlement amount can be estimated. Ameren, UE, CIPS, CILCO and IP recognize revenues associated with resettlements in accordance with authoritative guidance on revenue recognition.

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 Missouri electric, Missouri natural gas, and Illinois 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 Illinois 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 2009, 2008 and 2007:

	2009	2008	2007
Ameren	**$ 168**	$ 172	$ 166
UE	**112**	109	110
CIPS	**15**	16	15
CILCO	**11**	13	11
IP	**30**	34	30

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, CIPS, Genco, CILCO, and IP 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’s net assets 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.

Earnings per Share

There were no material differences between Ameren’s basic and diluted earnings per share amounts in 2009, 2008, and 2007. 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 and 35,545 shares in 2007. There were no assumed stock option conversions in 2009, as the remaining stock options were not dilutive.

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.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued authoritative guidance that established accounting and reporting standards for minority interests, which were recharacterized as noncontrolling interests. This guidance requires noncontrolling interests to be classified as a component of equity separate from the parent’s equity; purchases or sales of equity interests that do not result in a change in control to be accounted for as equity transactions; net income attributable to the noncontrolling interest to be included in consolidated net income in the statement of income; and upon a loss of control, the interest sold, as well as any interest retained, to be recorded at fair value, with any gain or loss recognized in earnings. We adopted the provisions of this guidance at the beginning of 2009. It applied prospectively, except for the presentation and disclosure requirements, for which it applied retroactively. See Noncontrolling Interests above for additional information.

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the FASB issued amended authoritative guidance that requires entities to provide greater transparency in interim and annual financial statements about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for, and how the instruments and related hedged items affect the financial position, results of operations, and cash flows of the entity. This guidance requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The adoption of this guidance, effective for us in the first quarter of 2009, did not have a material impact on our results of operations, financial position, or liquidity because it required enhanced disclosure only. See Note 7 - Derivative Financial Instruments for additional information.

Employers' Disclosures about Postretirement Benefit Plan Assets

In December 2008, the FASB issued authoritative guidance regarding additional disclosures related to pension and other postretirement benefit plan assets. Required additional disclosures include those related to the investment allocation decision-making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to measure fair value and significant concentrations of risk within the plan assets. The adoption of this guidance, effective for us as of December 31, 2009, did not have a material impact on our results of operations, financial position, or liquidity, because it provided enhanced disclosure requirements only. See Note 11 - Retirement Benefits for additional information.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly

In April 2009, the FASB issued additional authoritative guidance regarding the factors that should be considered in estimating fair value when there has been a significant decrease in market activity for an asset or liability. The guidance, which applies to all fair value measurements, does not change the objective of a fair value measurement. The adoption of this guidance, effective for us as of June 30, 2009, did not have a material impact on our results of operations, financial position, or liquidity.

Recognition and Presentation of Other-Than-Temporary Impairments

In April 2009, the FASB issued authoritative guidance that established a new method of recognizing and reporting other-than-temporary impairments of debt securities. It contains additional annual and interim disclosure requirements related to debt and equity securities. Under the new guidance, an impairment of debt securities is other-than-temporary if (1) the entity intends to sell the security, (2) it is more likely than not that the entity will be required to sell the security before recovery of its amortized cost basis, or (3) the entity does not expect to recover the security's entire amortized cost basis. The adoption of this guidance, effective for us as of June 30, 2009, did not have a material impact on our results of operations, financial position, or liquidity.

Subsequent Events

In May 2009, the FASB issued authoritative guidance that established general standards of accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The adoption of this guidance, effective for us as of June 30, 2009, did not have a material impact on our results of operations, financial position, or liquidity. In February 2010, the FASB issued amended guidance, which was effective upon issuance. The adoption of the amended guidance did not have a material impact on our results of operations, financial position, or liquidity.

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles

In June 2009, the FASB issued the FASB Accounting Standards Codification (the "Codification"), which is the primary source of authoritative GAAP to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The Codification modifies the hierarchy of GAAP to include only two levels: authoritative and nonauthoritative. The Codification supersedes all non-SEC accounting and reporting standards. The adoption of the Codification, effective for us as of July 1, 2009, did not affect our results of operations, financial position, or liquidity.

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 based on whether the entity (1) has the power to direct matters that most significantly affect the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. Further, the guidance 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 in the first quarter of 2010, with the exception of guidance applicable to detailed Level 3 reconciliation disclosures, which will be effective for us in the first quarter of 2011. The adoption of this guidance will not have a material impact on our results of operations, financial position, or liquidity because it provides enhanced disclosure requirements only.

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, Genco and CILCO 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, CIPS, and IP 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 2009 and 2008:

	Ameren(a)(b)(c)	UE(b)	CIPS(d)	Genco(c)	CILCO	IP(d)
Balance at December 31, 2007	$ 567	$ 476	$ 2	$ 52	$ 28	$ 2
Liabilities settled	(3)	(e)	-	(1)	(2)	(e)
Accretion in 2008(f)	33	27	(e)	3	2	(e)
Change in estimates(g)	(186)	(186)	-	(e)	(e)	-
Balance at December 31, 2008	$ 411	$ 317	$ 2	$ 54	$ 28	$ 2
Liabilities incurred	**$ (e)**	**$ -**	**$ -**	**$ -**	**$ (e)**	**$ -**
Liabilities settled	**(3)**	**(2)**	**-**	**(e)**	**(e)**	**-**
Accretion in 2009(f)	**24**	**18**	**(e)**	**4**	**2**	**(e)**
Change in estimates(h)	**2**	**(2)**	**(e)**	**(e)**	**4**	**(e)**
Balance at December 31, 2009	**$ 434**	**$ 331**	**$ 2**	**$ 58**	**$ 34**	**$ 2**

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) The nuclear decommissioning trust fund assets of $293 million and $239 million as of December 31, 2009 and 2008, respectively, were restricted for decommissioning of the Callaway nuclear plant.
(c) Balance included $5 million in Other Current Liabilities on the balance sheet.
(d) Balance included in Other Deferred Credits and Liabilities on the balance sheet.
(e) Less than $1 million.
(f) All accretion expense was recorded as an increase to regulatory assets, except for Genco and CILCO (AERG).
(g) UE changed estimates related to its Callaway nuclear plant decommissioning costs based on a cost study performed in 2008, a change in assumptions related to plant life, and a decline in the cost escalation factor assumptions.
(h) UE and CILCO changed estimates for asbestos removal. Additionally, CILCO changed related estimates to retirement costs for its ash ponds.

Variable-Interest Entities

According to authoritative accounting guidance regarding variable-interest entities (VIEs), an entity is considered a VIE if it does not have sufficient equity to finance its activities without assistance from variable-interest holders, or if its equity investors lack any of the following characteristics of a controlling financial interest: control through voting rights, the obligation to absorb expected losses, or the right to receive expected residual returns. Ameren and its subsidiaries review their equity interests, debt obligations, leases, contracts, and other agreements to determine their relationship to a VIE. We have determined that the following significant VIEs were held by the Ameren Companies at December 31, 2009:

Affordable housing partnership investments. At December 31, 2009 and 2008, Ameren had investments in multiple affordable housing and low-income real estate development partnerships as well as an investment in a commercial real estate development partnership of $64 million and $82 million in the aggregate, respectively. For these variable-interests, Ameren is a limited partner. It owns less than a 50 percent interest and receives the benefits and accepts the risks consistent with its limited partner interest. We have concluded that Ameren is not the primary beneficiary of any of the VIEs related to these investments because Ameren would not absorb a majority of the entity's losses. These investments are classified as Other Assets on Ameren's consolidated balance sheet. The maximum exposure to loss as a result of these variable interests is limited to the investments in these arrangements.

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.

Employee Separation and Other Charges

In the third quarter of 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, CIPS, Genco, CILCO and IP. Additionally, in November 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, CIPS - $1 million, Genco - $5 million, CILCO - $2 million, and IP - $1 million) for the severance costs related to both the voluntary and involuntary separation programs as well as for Merchant Generation staff reductions announced in the third quarter of 2009. These charges were recorded in other operations and maintenance expense in the applicable statements of income. Substantially all of this 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.

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. In September 2009, the Circuit Court of Pemiscot County 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. The merits of the appeal continue to be briefed by the parties. A decision is likely to be issued by the Circuit Court of Pemiscot County in the second quarter of 2010. During the stay, Noranda will pay into the court registry the contested portion of its monthly billings, approximately $0.5 million per month based on current usage levels. If UE wins the appeal, it will receive those monthly payments plus interest.

Pending Electric Rate Case

UE filed a request with the MoPSC in July 2009 to increase its annual revenues for electric service by $402 million. Included in this increase request was approximately $227 million of anticipated increases in normalized net fuel costs in excess of the net fuel costs included in base rates previously authorized by the MoPSC in its January 2009 electric rate order, which, absent initiation of this general rate proceeding, would have been eligible for recovery through UE's existing FAC. The balance of the increase request is based primarily on investments made to continue systemwide reliability improvements for customers, increases in costs essential to generating and delivering electricity, and higher financing costs. The initial electric rate increase request was based on an 11.5% return on equity, a capital structure composed of 47.4% equity, a rate base for UE of $6.0 billion, and a test year ended March 31, 2009, with certain pro-forma adjustments through the anticipated true-up date of January 31, 2010. In February 2010, UE filed rebuttal testimony relating to certain positions taken by interveners in the rate case and modified its recommended return on equity to 10.8%.

UE's initial filing included a request for interim rate relief, which would have placed into effect approximately $37 million of the requested increase prior to completion of the full rate case. In January 2010, the MoPSC denied UE's request for interim rate relief.

As part of its filing, UE also requested that the MoPSC approve the implementation of an environmental cost recovery mechanism and a storm restoration cost tracker. The environmental cost recovery mechanism, if approved, would allow UE to adjust electric rates twice each year outside of general rate proceedings to reflect changes in its prudently incurred costs to comply with federal, state, or local environmental laws, regulations, or rules greater than or less than the amount set in base rates. Rate adjustments pursuant to this cost recovery mechanism would not be permitted to exceed an annual amount equal to 2.5% of UE's gross jurisdictional electric revenues and would be subject to prudency reviews by the MoPSC. UE's request was consistent with the environmental cost recovery rules approved by the MoPSC in April 2009. The storm restoration cost tracker would permit UE a more timely recovery of storm restoration operations and maintenance expenditures.

In addition, UE requested that the MoPSC approve the continued use of the FAC and the vegetation management and infrastructure inspection cost tracking mechanism that the MoPSC previously authorized in its January 2009 electric rate order, and the continued use of the regulatory tracking mechanism for pension and postretirement benefit costs that the MoPSC previously authorized in its May 2007 electric rate order. The UE request included the discontinuation of the SO_2 emission allowance sales tracker.

UE's filing with the MoPSC also seeks approval to revise the tariff under which it serves Noranda to prospectively address the significant lost revenues UE can incur due to any future operational issues at Noranda's smelter plant in southeastern Missouri, such as the revenue losses resulting from the January 2009 storm-related power outage.

The MoPSC staff has responded to the UE request for an electric service rate increase. The MoPSC staff has recommended an increase to UE's annual revenues of between $218 million to $251 million based on a return on equity range of 9.0% to 9.7%. Included in this recommendation was approximately $214 million of increases in normalized net fuel costs. Other parties also made recommendations through testimony filed in this case. MoPSC staff and other parties have expressed opposition to some of the requested cost recovery mechanisms as well as the proposed Noranda tariff revision.

The MoPSC proceeding relating to the proposed electric service rate changes will take place over a period of up to 11 months, and a decision by the MoPSC in such proceeding is required by the end of June 2010. Hearings are scheduled in March 2010. UE cannot predict the level of any electric service rate change the MoPSC may approve, when any rate change may go into effect, whether the cost recovery mechanisms and trackers requested will be approved or continued, or whether any rate change that may eventually be approved will be sufficient to enable UE to recover its costs and earn a reasonable return on its investments when the rate change goes into effect.

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 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 the procurement of renewable energy or renewable energy credits. Rules implementing the renewable energy portfolio requirement are expected to be issued by the MoPSC in 2010. UE expects that any related costs or investments would ultimately be recovered in rates. In January 2010, UE issued an RFP to solicit solar renewable energy credits and energy in 2011 to meet the solar portion of this requirement. UE is currently evaluating the responses.

Missouri Energy Efficiency Investment Act

In July 2009, the Missouri governor signed a law that went into effect in August 2009, which, among other things, allows electric utilities to recover costs related to MoPSC-approved energy efficiency programs. Recovery is permitted only if the program is approved by the MoPSC, results in energy savings, and is beneficial to all customers in the class for which the program is proposed. The new law could potentially, 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.

Illinois

2008 Electric and Natural Gas Delivery Service Rate Order

On September 24, 2008, the ICC issued a consolidated order approving a net increase in annual revenues for electric delivery service of $123 million in the aggregate (CIPS - $22 million increase, CILCO - $3 million decrease, and IP - $104 million increase) and a net increase in annual revenues for natural gas delivery service of $38 million in the aggregate (CIPS - $7 million increase, CILCO - $9 million decrease, and IP - $40 million increase), based on a 10.65% return on equity with respect to electric delivery service and a 10.68% return on equity with respect to natural gas delivery service. These rate changes were effective on October 1, 2008.

In October 2008, CIPS, CILCO and IP and other parties requested that the ICC rehear certain aspects of its September 2008 consolidated order. In November 2008, the ICC denied all rate order rehearing requests filed by the Ameren Illinois Utilities and other parties. In December 2008, the Illinois attorney general appealed the rate order to the Appellate Court of Illinois, Fourth District, specifically, the ICC's affirmation of the recovery of a certain amount of fixed costs in the customer charge. In December 2009, the Appellate Court denied the Illinois attorney general's appeal and sustained the ICC rate order.

Pending Electric and Natural Gas Delivery Service Rate Cases

In June 2009, CIPS, CILCO and IP filed requests with the ICC to increase their annual revenues for electric delivery service. The currently pending requests, as amended, seek to increase annual revenues from electric delivery service by $115 million in the aggregate (CIPS - $38 million, CILCO - $17 million, and IP - $60 million). Additionally, the Ameren Illinois Utilities requested moving more of the electric delivery costs into the monthly non-volumetric charge, similar to the natural gas delivery rate design change approved by the ICC in 2008. The electric rate increase requests were based on an 11.3% to 11.7% return on equity, a capital structure composed of 44% to 49% equity, an aggregate rate base for the Ameren Illinois Utilities of $2.3 billion, and a test year ended December 31, 2008, with certain known and measurable adjustments through May 2010.

CIPS, CILCO and IP also filed requests with the ICC in June 2009 to increase their annual revenues for natural gas delivery service. The currently pending requests, as amended, seek to increase annual revenues for natural gas delivery service by $15 million in the aggregate (CIPS - $6 million, CILCO - $2 million, and IP - $7 million). The natural gas rate increase requests were based on a 10.8% to 11.2% return on equity, a capital structure composed of 44% to 49% equity, an aggregate rate base for the Ameren Illinois Utilities of $1.0 billion, and a test year ended December 31, 2008, with certain known and measurable adjustments through May 2010.

The ICC staff has responded to the filed requests by the Ameren Illinois Utilities. The ICC staff has recommended, as amended, a net increase in revenues for electric delivery service for the Ameren Illinois Utilities of $57 million in the aggregate (CIPS - $21 million increase, CILCO - $5 million increase, and IP - $31 million increase) and a net decrease in revenues for natural gas delivery service of $11 million in the aggregate (CILCO - $6 million decrease and IP - $5 million decrease). The ICC staff position was based on a 10.1% to 10.4% return on equity for electric delivery service and a 9.4% to 9.6% return on equity for natural gas delivery service. Other parties also made recommendations through testimony filed in the electric and natural gas delivery service rate cases.

In February 2010, administrative law judges issued a consolidated proposed order, which included a recommended revenue increase for electric delivery service for the Ameren Illinois Utilities of $66 million in the aggregate (CIPS - $26 million increase, CILCO - $6 million increase, and IP - $34 million increase) and a recommended revenue net decrease for natural gas delivery service of $10 million in the aggregate (CIPS - $1 million increase, CILCO - $6 million decrease, and IP - $5 million decrease). The ICC is not bound by the proposed order issued by the administrative law judges.

The ICC proceedings relating to the proposed electric and natural gas delivery service rate changes will take place over a period of up to 11 months, and decisions by the ICC in such proceedings are required by May 2010. The Ameren Illinois Utilities 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 the Ameren Illinois Utilities to recover their costs and earn a reasonable return on their 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 the Ameren Illinois Utilities. Pursuant to the 2007 Illinois Electric Settlement Agreement, the Ameren Illinois Utilities, Genco, and CILCO (AERG) agreed to make aggregate contributions of $150 million over the four-year period, with $60 million coming from the Ameren Illinois Utilities (CIPS - $21 million; CILCO - $11 million; IP - $28 million), $62 million from Genco, and $28 million from CILCO (AERG). See Note 15 - Commitments and Contingencies for information on the remaining contributions to be made as of December 31, 2009.

The Ameren Illinois Utilities, Genco, and CILCO (AERG) recognize 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, CIPS, CILCO (Illinois Regulated), IP, Genco, and CILCO (AERG) incurred charges to earnings, primarily recorded as a reduction to electric operating revenues, during the year ended December 31, 2009, of $25 million, $3 million, $2 million, $5 million, $10 million, and $5 million, respectively (year ended December 31, 2008 - $42 million, $6 million, $3 million, $8 million, $17 million, and $8 million, respectively) under the terms of the 2007 Illinois Electric Settlement Agreement.

Other electric generators and utilities in Illinois agreed to contribute $851 million to the comprehensive rate relief and customer assistance program. Contributions by the other electric generators (the generators) and utilities to the comprehensive program are subject to funding agreements. Under these agreements, at the end of each month, the Ameren Illinois Utilities send a bill, due in 30 days, to the generators and utilities for their proportionate share of that month’s rate relief and assistance. If any escrow funds have been provided by the generators, these funds will be drawn upon before reimbursement is sought from the generators. At December 31, 2009, Ameren, CIPS, CILCO (Illinois Regulated) and IP had receivable balances from nonaffiliated Illinois generators for reimbursement of customer rate relief and program funding of $10 million, $3 million, $2 million, and $5 million, respectively. See Note 14 - Related Party Transactions for information on the impact of intercompany settlements.

The 2007 Illinois Electric Settlement Agreement provided that if before August 1, 2011, legislation is enacted in Illinois freezing or reducing retail electric rates, or imposing or authorizing a new tax, special assessment, or fee on the generation of electricity, then the remaining commitments under the 2007 Illinois Electric Settlement Agreement would expire, and any funds set aside in support of the commitments would be refunded to the utilities and Generators.

Power Procurement

As part of the 2007 Illinois Electric Settlement Agreement, the reverse auction used for power procurement in Illinois was discontinued. However, one-third of the existing supply contracts from the September 2006 reverse power procurement auction remain in place through May 2010. A new competitive power procurement process led by the IPA, which was established as a part of the 2007 Illinois Electric Settlement Agreement, was implemented beginning in January 2009. In January 2009, the ICC approved the electric power procurement plan filed by the IPA for both the Ameren Illinois Utilities and Commonwealth Edison Company. The plan outlined the wholesale products that the IPA procured on behalf of the Ameren Illinois Utilities for the period June 1, 2009, through May 31, 2014. The IPA procured capacity, energy swaps, and renewable energy credits through an RFP process on behalf of the Ameren Illinois Utilities in the second quarter of 2009. See Note 14 - Related Party Transactions and Note 15 - Commitments and Contingencies for additional information about the Ameren Illinois Utilities’ purchased power agreements.

In December 2009, the ICC approved a plan for procurement of electric power for the Ameren Illinois Utilities and Commonwealth Edison Company for the period June 1, 2010, through May 31, 2015. The IPA will procure energy swaps, capacity and renewable energy credits and long-term renewable supply. The exact dates of each procurement event have not been determined. Following successful completion of the proposed 2010 procurement events, the Ameren Illinois Utilities will have sufficient capacity and energy hedges in place for 100% of their expected supply obligation for the period June 2010 through May 2011, 70% of their expected supply obligation for the period June 2011 through May 2012, and 44% of their expected supply obligations for the period June 2012 through May 2013. The Ameren Illinois Utilities will also have sufficient renewable energy credits to satisfy the 2010 planning year requirement along with 20-year renewable supply contracts consisting of 600,000 megawatthours per year of renewable energy power and credits with deliveries beginning June 1, 2012.

Also as part of the 2007 Illinois Electric Settlement Agreement, the Ameren Illinois Utilities 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 relevant market prices. See Note 7 - Derivative Financial Instruments and Note 14 - Related Party Transactions for additional information on these financial contracts.

ICC Reliability Audit

In August 2007, the ICC retained Liberty Consulting Group to investigate, analyze, and report to the ICC on the Ameren Illinois Utilities' 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 the Ameren Illinois Utilities to improve their systems and their response to emergencies. The ICC directed the Ameren Illinois Utilities to present to the ICC a plan to implement Liberty Consulting Group's recommendations. The plan was submitted to the ICC in November 2008. Liberty Consulting Group will monitor the Ameren Illinois Utilities' efforts to implement the recommendations and any initiatives that the Ameren Illinois Utilities undertake. The Ameren Illinois Utilities expect they could incur an estimated $20 million ($15 million for distribution and $5 million for transmission) of capital costs and an estimated $66 million ($50 million for distribution and $16 million for transmission) of cumulative operations and maintenance expenses for the 2010 through 2013 time frame in order to implement the recommendations.

In December 2009, the Ameren Illinois Utilities requested ICC approval of a rider mechanism to recover the distribution-related costs associated with the Liberty Consulting Group's recommendations. This request replaced a previous request for a rider mechanism, which had been part of the pending electric delivery rate cases. There is no statutory date by which the ICC must act, and no schedule is currently in place for this request.

The Ameren Illinois Utilities have committed to implement various audit recommendations, as outlined in their November 2008 plan. However, in order to fulfill that commitment in a timely manner, they must be able to synchronize the timing of their distribution-implementation expenditures with the recognition of those costs in rates. Without the necessary funding or a rider mechanism to recover the distribution costs, the Ameren Illinois Utilities may defer some of the projects until the distribution costs can be recovered either in base rates or through some other cost recovery mechanism.

Transmission-related costs, as incurred, will be recoverable through FERC's ratemaking proceedings.

Illinois 2009 Energy Legislation

In July 2009, a new law became effective in Illinois that, among other things, established new energy efficiency targets for Illinois natural gas utilities, developed a percentage of income payment plan for low-income utility customers, and allowed 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 the Ameren Illinois Utilities' electric and natural gas rate adjustment tariffs to recover bad debt expense not recovered in base rates. The tariffs provide utilities the ability to adjust their base rates annually through a rate adjustment mechanism that applies to 2008 and subsequent years. Upon ICC approval of the rate adjustment tariffs in February 2010, the Ameren Illinois Utilities made a one-time $10 million donation (CIPS - $2 million, CILCO - $2 million, and IP - $6 million) for customer assistance programs, as required by the legislation. The amount of the required one-time donation and the impact of the net recovery of 2008 and 2009 bad debt expenses were reflected in 2009 earnings.

Federal

Regional Transmission Organization

UE, CIPS, CILCO and IP are transmission-owning members of MISO, which is a FERC-regulated RTO that provides transmission tariff administration services for electric transmission systems. In early 2004, UE received authorization from the MoPSC to participate in MISO for a five-year period, with further participation subject to approval by the MoPSC. The MoPSC required UE to file a study evaluating the costs and benefits of its participation in MISO prior to the end of the five-year period. The MoPSC also directed UE to enter into a service agreement with MISO to provide transmission service to UE's bundled retail customers. The service agreement's primary function was to ensure that the MoPSC continued to set the transmission component of UE's rates to serve its bundled retail load. Among other things, the service agreement provided that UE would not pay MISO for transmission service to UE's bundled retail customers. FERC approved the service agreement in the form that was acceptable to the MoPSC.

Due to changes to MISO's allocation of transmission revenues to transmission owners, UE believed it should have received incremental annual transmission revenues of $60 million as of February 2008 in accordance with its service agreement with MISO. Numerous transmission owners in MISO, along with MISO itself as the tariff administrator, filed with FERC in December 2007 requesting changes to the MISO tariff to prevent UE from collecting these additional transmission revenues. In December 2007, UE filed a protest to these proposed MISO tariff changes, calling them unauthorized and improper in light of the MoPSC's requirement for the service agreement between UE and MISO discussed above. In February 2008, FERC issued an order accepting the tariff changes proposed by MISO and by certain transmission owners in MISO. In March 2008, UE filed a request with FERC for a rehearing of its order. In April 2008, FERC suspended UE's request for rehearing to allow time for further consideration by FERC. UE is unable to predict if or when FERC may issue a further order in this proceeding.

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 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, as discussed above. In June 2008, a stipulation and agreement among UE, the MoPSC staff, MISO and other parties to the proceeding was filed with the MoPSC, which provided for UE's continued, conditional MISO participation through April 30, 2012. The stipulation and agreement 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. The MoPSC issued an order, effective September 19, 2008, approving the stipulation and agreement. If UE were to withdraw from MISO in the future, it might need to obtain FERC approval and to meet conditions imposed by FERC, in addition to obtaining MoPSC's approval.

Seams Elimination Cost Adjustment

Pursuant to a series of FERC orders, FERC put Seams Elimination Cost Adjustment (SECA) charges into effect on December 1, 2004, subject to refund and hearing procedures. The SECA charges were a transition mechanism in place for 16 months, from December 1, 2004, to March 31, 2006, to compensate transmission owners in MISO and PJM for revenues lost when FERC eliminated the regional through-and-out rates previously applicable to transactions crossing the border between MISO and PJM. The SECA charge was a nonbypassable surcharge payable by load-serving entities in proportion to the benefit they realized from the elimination of the regional through-and-out rates as of December 1, 2004. The MISO transmission owners (including UE, CIPS, CILCO and IP) and the PJM transmission owners filed their proposed SECA charges in November 2004, as compliance filings pursuant to FERC order. A FERC administrative law judge issued an initial decision in August 2006, recommending that FERC reject both of the SECA compliance filings (the filing for SECA charges made by the transmission owners in the MISO and the filing for SECA charges made by the transmission owners in PJM). Several parties filed rehearing requests of this initial decision. There is no date scheduled for FERC to act on the initial decision. Both before and after the initial decision, various parties (including UE, CIPS, CILCO and IP as part of the group of MISO transmission owners) filed numerous bilateral or multiparty settlements. To date, FERC has approved many of the settlements and has rejected none of the settlements. Neither the MISO transmission owners, including UE, CIPS, CILCO and IP, nor the PJM transmission owners have been able to settle with all parties. During the transition period of December 1, 2004, to March 31, 2006, Ameren, UE, CIPS, and IP received net revenues from the SECA charges of $10 million, $3 million, $1 million, and $6 million, respectively. CILCO's net SECA charges were less than $1 million. In December 2009, a party that has not settled its SECA charges filed with the U.S. Court of Appeals for the District of Columbia Circuit seeking an order directing the FERC to resolve the SECA matters. In response to this filing, in January 2010, FERC agreed to issue an order on the SECA initial decision and rehearing requests by the end of May 2010. While we cannot predict the ultimate outcome of the SECA proceedings, we do not believe the outcome of the proceedings will have a material effect on UE's, CIPS', CILCO's and IP's costs and revenues.

FERC Order - MISO Charges

In May 2007, UE, CIPS, CILCO and IP filed with the U.S. Court of Appeals for the District of Columbia Circuit an appeal of FERC's March 2007 order involving the reallocation of certain MISO operational costs among MISO participants retroactive to 2005. In August 2007, the court granted FERC's motion to hold the appeal in abeyance until the end of the continuing proceedings at FERC regarding these costs. Other MISO participants also filed appeals. On August 10, 2007, UE, CIPS, CILCO, and IP filed a complaint with FERC regarding the MISO tariff's allocation methodology for these same MISO operational charges. In November 2007, FERC issued two orders relative to these allocation matters. One of these orders addressed requests for rehearing of prior orders in the proceedings, and one concerned MISO's compliance with FERC's orders to date in the proceedings. In December 2007, UE, CIPS, CILCO and IP requested FERC's clarification or rehearing of its November 2007 order regarding MISO's compliance with FERC's orders. UE, CIPS, CILCO and IP maintained that MISO was required to reallocate certain of MISO's operational costs among MISO market participants, which would result in refunds to UE, CIPS, CILCO and IP retroactive to April 2006. On November 7, 2008, FERC issued an order granting the request for clarification. FERC directed MISO to reallocate certain MISO operational costs among MISO participants and provide refunds for the period April 2006 to August 2007 ("November 7, 2008 Clarification Order"). On November 10, 2008, FERC granted further relief requested in the complaints filed by UE, CIPS, CILCO, IP and others regarding further reallocation for these MISO operational charges and directed MISO to calculate refunds for the period from August 10, 2007, forward ("November 10, 2008 Complaint Order").

Several parties to these proceedings protested MISO's proposed implementation of these refunds, requested rehearing of FERC's orders and, in some cases, appealed FERC's orders to the courts. In March 2009, MISO began resettling its markets to provide refunds as FERC directed retroactive from August 10, 2007. In May 2009, FERC issued an order that upheld most of the conclusions of the November 10, 2008 Complaint Order but changed the effective date for refunds such that certain operational costs will be allocated among MISO market participants beginning November 10, 2008, instead of August 10, 2007. In June 2009, UE, CIPS, CILCO and IP filed for rehearing of the May 2009 order regarding the change to the refund effective date. This rehearing request is pending.

With respect to the November 7, 2008 Clarification Order, in June 2009 FERC issued an order dismissing rehearing requests of such clarification 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 25, 2006, through November 4, 2007. UE, CIPS, CILCO and IP filed a request for rehearing in July 2009. This rehearing request is pending.

With respect to the two rehearing requests discussed above, UE, CIPS, CILCO and IP do not believe that the ultimate resolution of either request will have a material effect on their results of operations, financial position, or liquidity.

MISO and PJM Dispute Resolution

During 2009, MISO and PJM discovered an error in the calculation quantifying certain transactions between the RTOs. The error, which originated in April 2005, at the initiation of the MISO Energy and Operating Reserves Market was corrected prospectively in June 2009. Since discovering the error, MISO and PJM have worked jointly to estimate its financial impact on the respective markets. MISO and PJM are in agreement about the methodology used to recalculate the market flows occurring from June 2007 to June 2009 for the resettlement due from PJM to MISO estimated at $65 million. MISO and PJM are not in agreement about the methodology used to recalculate the market flows occurring from April 2005 to May 2007, nor are they in agreement about the resettlement amount. To resolve this issue, MISO and PJM have agreed to participate in FERC's dispute resolution and settlement process in order to determine a resettlement amount for the entire period from April 2005 to June 2009. In October 2009, an administrative law judge was appointed as mediator, and multiple settlement conferences were held at FERC in late 2009 and early 2010. A final settlement between MISO and PJM, if and when reached, will probably require filings to be made by PJM and MISO with FERC. Ameren and its subsidiaries may receive a to-be-determined portion of the resettlement amount due from PJM to MISO. No prospective refund has been recorded related to this matter. Until a settlement has been reached and approved by FERC, we cannot predict the ultimate impact of these proceedings on Ameren's, UE's, CIPS', Genco's, CILCORP's, CILCO's and IP's results of operations, financial position, or liquidity.

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 has 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 to UE. In February 2010, Entergy filed a request for rehearing of the January 2010 opinion. UE has recorded the additional charges related to the July 2007 order, but has not recorded any prospective refund. UE is unable to predict how or when the FERC will rule on the motions. Therefore, UE is unable to predict whether FERC ultimately will order Entergy to refund to UE the additional charges.

Additionally, 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, although FERC's ruling in January 2010, discussed above, assuming it is upheld after any rehearings or appeals, likely will prevent FERC from ordering UE to pay any amounts retroactively. Based on existing facts and circumstances, UE believes that the likelihood of incurring this $25 million expense is not probable. Thus no liability has been recorded as of December 31, 2009. UE plans to participate in any proceeding that FERC initiates to address the court's decisions.

Nuclear Combined Construction and Operating License Application

In July 2008, UE filed an application with the NRC for a combined construction and operating license for a new 1,600-megawatt nuclear unit at UE's existing Callaway County, Missouri, nuclear plant site. UE also signed contracts for COLA-related services and certain long lead-time nuclear-unit related equipment (heavy forgings).

In early 2009, the Missouri Clean and Renewable Energy Construction Act was separately introduced in both the Missouri Senate and House of Representatives. One purpose of these bills was to allow the MoPSC to authorize utilities to recover the costs of financing and tax payments associated with a new generating plant while that plant is being constructed. Recovery of actual construction costs still would not begin until a plant goes into service. UE believes legislation allowing timely recovery of financing costs during construction must be enacted in order for it to build a new nuclear unit to meet its baseload generation capacity needs. However, passage of this or other legislation was not a commitment or guarantee that UE would build a new nuclear unit.

In April 2009, senior management of UE announced that they had asked the legislative sponsors of the Missouri Clean and Renewable Energy Construction Act to withdraw the bills from consideration by the Missouri General Assembly. UE believed that the legislation being considered in the Missouri Senate in its then proposed form would not provide UE with the financial and regulatory certainty it needed to pursue the project. As a result, UE announced that it was suspending its efforts to build a new nuclear unit at its existing Missouri nuclear plant site. In June 2009, UE requested the NRC suspend review of the COLA and all activities related to the COLA. The contract for COLA-related services was amended in December 2009 in several respects, including changes to the termination provisions in light of UE's decision to suspend its efforts to build a new nuclear unit. UE will consider all available and feasible generation options to meet future customer requirements as part of an integrated resource plan that UE will file with the MoPSC in 2011.

As of December 31, 2009, UE had capitalized approximately $69 million as construction work in progress related to the COLA. The 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, it is possible that a charge to earnings could be recognized in a future period.

Prior to June 30, 2009, UE made contractual payments to the heavy forgings manufacturer of $14 million and had remaining contractual commitments of $81 million. In July 2009, when an agreement was reached with the heavy forgings manufacturer to terminate the heavy forgings procurement agreement, $5 million in previous payments was retained by the manufacturer as a penalty for terminating the contract. That amount was charged to earnings in June 2009.

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 current FERC license expires on June 30, 2010. Approval and relicensure are expected in 2012. Operations are permitted to continue under the current license while the application for relicensing is pending.

Regulatory Assets and Liabilities

In accordance with authoritative accounting guidance regarding accounting for the effects of certain types of regulation, UE, CIPS, CILCO and IP defer certain costs pursuant to actions of regulators or based on the expected ability to recover such costs in rates charged to customers. UE, CIPS, CILCO and IP 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 our regulatory assets and regulatory liabilities at December 31, 2009 and 2008:

	Ameren[a]	UE	CIPS	CILCO	IP
2009:					
Current regulatory assets:					
Under-recovered FAC[b][c]	$ 39	$ 39	$ -	$ -	$ -
Under-recovered Illinois electric power costs[b][d]	5	-	2	2	1

Under-recovered PGA(b)(d)	4	-	4	-	-
MTM derivative assets(e)	62	24	53	27	85
Total current regulatory assets(f)	$ 110	$ 63	$ 59	$ 29	$ 86
Noncurrent regulatory assets:					
Pension and postretirement benefit costs(g)	$ 659	$ 288	$ 75	$ 93	$ 203
Income taxes(h)	280	272	5	1	2
Asset retirement obligation(i)	36	31	2	1	2
Callaway costs(b)(j)	55	55	-	-	-
Unamortized loss on reacquired debt(b)(k)	56	26	5	5	20
Recoverable costs - contaminated facilities(l)	150	-	47	-	103
IP integration(m)	17	-	-	-	17
Recoverable costs - debt fair value adjustment(n)	6	-	-	-	6
MTM derivatives assets(o)	49	10	103	57	164
SO_2 emission allowances sale tracker(p)	16	16	-	-	-
FERC-ordered MISO resettlements - March 2007(q)	7	7	-	-	-
Vegetation management and infrastructure inspection(r)	7	7	-	-	-
Storm costs(s)	27	27	-	-	-
Demand-side costs(t)	15	15	-	-	-
Reserve for workers' compensation liabilities(u)	15	9	3	-	3
Bad debt rider(v)	30	-	7	4	19
Other(w)	5	2	1	1	1
Total noncurrent regulatory assets	$ 1,430	$ 765	$ 248	$ 162	$ 540

	Ameren(a)	UE	CIPS	CILCO	IP
Current regulatory liabilities:					
Over-recovered FAC(x)	$ 10	$ 10	$ -	$ -	$ -
Over-recovered Illinois electric power costs(d)	44	-	7	17	20
Over-recovered PGA(d)	13	4	2	4	3
MTM derivative liabilities(y)	15	11	1	2	1
Total current regulatory liabilities(z)	$ 82	$ 25	$ 10	$ 23	$ 24
Noncurrent regulatory liabilities:					
Income taxes(aa)	$ 160	$ 141	$ 10	$ 9	$ -
Removal costs(bb)	1,084	716	231	199	86
Emission allowances(cc)	35	35	-	-	-
Vegetation management and infrastructure inspection(dd)	2	2	-	-	-
MTM derivative liabilities(ee)	14	12	-	1	1
Bad debt rider(ff)	2	-	1	-	1
Pension and postretirement benefit costs tracker(gg)	41	41	-	-	-
Total noncurrent regulatory liabilities	$ 1,338	$ 947	$ 242	$ 209	$ 88
2008:					
Current regulatory assets:					
Under-recovered Illinois electric power costs(b)(d)	$ 2	$ -	$ 1	$ -	$ 1
Under-recovered PGA(b)(d)	1	-	1	-	-
MTM derivative assets(e)	79	10	30	24	57
Total current regulatory assets(f)	$ 82	$ 10	$ 32	$ 24	$ 58
Noncurrent regulatory assets:					
Pension and postretirement benefit costs(g)	$ 936	$ 410	$ 107	$ 125	$ 294
Income taxes(h)	255	248	6	-	1
Asset retirement obligation(i)	65	60	2	1	2
Callaway costs(b)(j)	58	58	-	-	-

Unamortized loss on reacquired debt(b)(k)	63	30	5	5	23
Recoverable costs - contaminated facilities(l)	97	-	18	8	71
IP integration(m)	33	-	-	-	33
Recoverable costs - debt fair value adjustment(n)	10	-	-	-	10
MTM derivative assets(o)	39	6	52	30	78
SO_2 emission allowances sale tracker(p)	13	13	-	-	-
FERC-ordered MISO resettlements - March 2007(q)	12	12	-	-	-
Vegetation management and infrastructure inspection(r)	9	9	-	-	-
Storm costs(s)	33	33	-	-	-
Demand-side costs(t)	4	4	-	-	-
Reserve for workers' compensation liabilities(u)	15	9	3	-	3
Other(w)	11	5	2	2	2
Total noncurrent regulatory assets	$ 1,653	$ 897	$ 195	$ 171	$ 517
Current regulatory liabilities:					
Over-recovered Illinois electric power costs(d)	$ 22	$ -	$ 6	$ 10	$ 6
Over-recovered PGA(d)	42	2	14	9	17
Total current regulatory liabilities(z)	$ 64	$ 2	$ 20	$ 19	$ 23
Noncurrent regulatory liabilities:					
Income taxes(aa)	$ 180	$ 154	$ 14	$ 12	$ -
Removal costs(bb)	1,018	675	220	194	76
Emission allowances(cc)	47	47	-	-	-
Pension and postretirement benefit costs tracker(gg)	41	41	-	-	-
MISO resettlements(hh)	5	5	-	-	-
Total noncurrent regulatory liabilities	$ 1,291	$ 922	$ 234	$ 206	$ 76

(a) Includes intercompany eliminations.
(b) These assets earn a return.
(c) Under-recovered fuel costs for the accumulation periods from June 2009 through September 2009 and October 2009 through December 2009. Recovery of the earlier accumulation period will begin in February 2010 while the recovery of the later accumulation period will begin in June 2010.
(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) Current portion of deferral of commodity-related derivative MTM losses, as well as the current portion of the MTM losses on financial contracts entered into by the Ameren Illinois Utilities with Marketing Company. See Illinois - Power Procurement Plan discussion above for additional information.
(f) Included in Current Regulatory Assets on the balance sheet of UE, CIPS, CILCO and IP and in Other Current Assets on the balance sheet of Ameren.
(g) 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.
(h) Offset to certain deferred tax liabilities for expected recovery of future income taxes when paid. See Note 13 - Income Taxes for amortization period.
(i) 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.
(j) 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.
(k) 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.
(l) The recoverable portion of accrued environmental site liabilities, primarily collected from electric and natural gas customers through ICC-approved cost recovery riders in Illinois. The period of recovery will depend on the timing of actual expenditures. See Note 15 - Commitments and Contingencies for additional information.
(m) Reorganization costs related to the integration and restructuring of IP into the Ameren system. Pursuant to the ICC order approving Ameren's acquisition of IP, these costs are recoverable in rates through 2010.
(n) A portion of IP's 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.
(o) Deferral of commodity-related derivative MTM losses, as well as the MTM losses on financial contracts entered into by the Ameren Illinois Utilities with Marketing Company. See Illinois - Power Procurement Plan discussion above for additional information.
(p) 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. In its pending rate case, UE requested the discontinuation of this tracker.
(q) Costs associated with a March 2007 FERC order that resettled costs among MISO market participants. The costs were previously charged to expense but were recorded as a regulatory asset. They will be amortized over a two-year period beginning March 1, 2009, as approved by the January 2009 MoPSC electric rate order.
(r) 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 1, 2008, through February 28, 2009, exceeded the amount allowed in base rates. The excess costs incurred between January 1, 2008, through September 30, 2008, are being amortized over three years, beginning on March 1, 2009, as approved by the January 2009 MoPSC electric rate order. The amortization period for the excess costs incurred from October 1, 2008, through February 28, 2009, will be determined in UE's pending electric rate case.
(s) 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 will be amortized over five years, beginning on March 1, 2009, as approved by the January

2009 MoPSC electric rate order.

(t) Demand-side costs, including the costs of developing, implementing and evaluating customer energy efficiency and demand response programs. These costs are being amortized over ten years, beginning on March 1, 2009, as approved by the January 2009 MoPSC electric rate order.

(u) Reserve for workers' compensation claims.

(v) A regulatory tracking mechanism for the difference between the level of bad debt expense incurred by the Ameren Illinois Utilities and the level of such costs built into electric and natural gas rates. The under-recovery relating to 2008 will be recovered from customers from March 2010 through December 2010. The under-recovery relating to 2009 will be recovered from customers from June 2010 through May 2011.

(w) Includes costs related to the Ameren Illinois Utilities' November 2007 electric and natural gas delivery service rate cases. The costs associated with the Ameren Illinois Utilities' electric delivery service rate cases are being amortized over a three-year period; the costs associated with the Ameren Illinois Utilities' natural gas delivery service rate cases are being amortized over a five-year period, as approved in the 2008 ICC rate order. In addition, the balance includes funding for low-income weatherization and other miscellaneous items.

(x) Over-recovered fuel costs for the accumulation period from March 2009 through May 2009. Customer refunds began in October 2009 and will continue through September 2010.

(y) Current portion of deferral of commodity-related derivative MTM gains.

(z) Included in Current Regulatory Liabilities on the balance sheet of IP and in Other Current Liabilities on the balance sheets of Ameren, UE, CIPS and CILCO.

(aa) Unamortized portion of investment tax credit and federal excess deferred taxes. See Note 13 - Income Taxes for amortization period.

(ab) 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.

(ac) The deferral of gains on emission allowance vintage swaps UE entered into during 2005. This gain will be amortized through February 2011.

(ad) 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. This over-recovery relates to the period March 1, 2009, through December 31, 2009. The amortization period for this over-recovery will be determined in a future UE electric rate case.

(ae) Deferral of commodity-related derivative MTM gains.

(af) A regulatory tracking mechanism for the difference between the level of bad debt expense incurred by the Ameren Illinois Utilities and the level of such costs built into electric and natural gas rates. The over-recovery relating to 2009 will be refunded to customers June 2010 through May 2011.

(ag) 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 effective June 4, 2007, as approved in a MoPSC order.

(ah) A portion of UE's expected refund relating to MISO resettlements associated with the November 2008 FERC orders. See Federal - FERC Order - MISO Charges discussion above for additional information.

UE, CIPS, CILCO and IP 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, 2009 and 2008:

	Ameren(a)(b)	UE(b)	CIPS	Genco	CILCO (Illinois Regulated)	CILCO (AERG)	IP
2009:							
Property and plant, at original cost:							
Electric	**$ 22,486**	**$ 13,627**	**$ 1,796**	**$ 2,730**	**$ 987**	**$ 1,251**	**$ 1,966**
Gas	**1,583**	**363**	**374**	**-**	**520**	**-**	**603**
Other	**406**	**85**	**6**	**6**	**3**	**2**	**21**
	24,475	**14,075**	**2,176**	**2,736**	**1,510**	**1,253**	**2,590**
Less: Accumulated depreciation and amortization	**8,787**	**5,760**	**923**	**1,032**	**730**	**295**	**176**
	15,688	**8,315**	**1,253**	**1,704**	**780**	**958**	**2,414**
Construction work in progress:							
Nuclear fuel in process	**271**	**271**	**-**	**-**	**-**	**-**	**-**
Other	**1,651**	**999**	**15**	**431**	**12**	**39**	**36**
Property and plant, net	**$ 17,610**	**$ 9,585**	**$ 1,268**	**$ 2,135**	**$ 792**	**$ 997**	**$ 2,450**
2008:							
Property and plant, at original cost:							
Electric	$ 21,244	$ 13,214	$ 1,744	$ 2,451	$ 954	$ 948	$ 1,840
Gas	1,505	347	365	-	506	-	565
Other	381	76	6	6	3	2	21
	23,130	13,637	2,115	2,457	1,463	950	2,426
Less: Accumulated depreciation and amortization	8,499	5,539	915	1,013	721	329	152
	14,631	8,098	1,200	1,444	742	621	2,274
Construction work in progress:							
Nuclear fuel in process	190	190	-	-	-	-	-

Other	1,746	707	12	506	12	359	55
Property and plant, net	$ 16,567	$ 8,995	$ 1,212	$ 1,950	$ 754	$ 980	$ 2,329

(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 with a gross asset value of $226 million and $222 million at December 31, 2009 and 2008, respectively. The total accumulated depreciation associated with the two CTs was $41 million and $36 million at December 31, 2009 and 2008, respectively.

The following table provides accrued capital expenditures at December 31, 2009, 2008, and 2007, which represent noncash investing activity excluded from the statements of cash flows:

	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
2009	$ **143**	$ **86**	$ **7**	$ **23**	$ **6**	$ **18**
2008	213	110	3	41	45	14
2007	153	76	3	28	35	7

(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, or drawings under committed bank credit facilities.

The following table summarizes the borrowing activity and relevant interest rates under the $1.15 billion credit facility described below for the years ended December 31, 2009 and 2008, respectively, and excludes letters of credit issued under the credit facility:

2009 Multiyear Credit Agreement ($1.15 billion)[(a)]	**Ameren (Parent)**	**UE**	**Genco**	**Total**
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%**
Prior $1.15 Billion Credit Facility				
2008:				
Average daily borrowings outstanding during 2008	$ 389	$ 154	$ 41	$ 584
Outstanding credit facility borrowings at period end	275	251	-	526
Weighted-average interest rate during 2008	3.58%	3.25%	3.97%	3.52%
Peak credit facility borrowings during 2008	$ 675	$ 493	$ 150	$ 1,068
Peak interest rate during 2008	7.25%	5.65%	5.53%	7.25%

(a) The 2009 Multiyear Credit Agreement amended and restated the Prior $1.15 Billion Credit Facility. Therefore, information in this table includes borrowing activity under the Prior $1.15 Billion Credit Facility.
(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 under all credit facilities during 2009 were $1 billion.

The following table summarizes the borrowing activity and relevant interest rates under the $150 million Supplemental Agreement described below for the year ended December 31, 2009:

Supplemental Agreement ($150 million)	**Ameren (Parent)**	**UE**	**Genco**	**Total**
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[(a)]	$ **91**	$ **53**	$ **17**	$ **109**
Peak interest rate during 2009	**5.50%**	**5.50%**	**3.56%**	**5.50%**

(a) 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 under all credit facilities during 2009 were $1 billion.

The following table summarizes the borrowing activity and relevant interest rates under the $800 million 2009 Illinois Credit Agreement described below for the year ended December 31, 2009:

2009 Illinois Credit Agreement ($800 million)	Ameren (Parent)	CIPS	CILCO (Parent)	IP	Total
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[(a)]	$ 200	$ -	$ -	$ -	$ 200
Peak interest rate during 2009	3.56%	-	-	-	3.56%

(a) 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 under all credit facilities during 2009 were $1 billion.

The following table summarizes the borrowing activity and relevant interest rates under the 2007 $500 million credit facility, which was terminated during 2009, for the years ended December 31, 2009 and 2008:

2007 $500 Million Credit Facility (Terminated)	CIPS	CILCO (Parent)	IP	AERG	Total[(a)]
2009:					
Average daily borrowings outstanding during 2009[(b)]	$ -	$ -	$ -	$ 59	$ 68
Outstanding credit facility borrowings at period end	-	-	-	-	-
Weighted-average interest rate during 2009[(b)]	-	-	-	1.42%	1.47%
Peak credit facility borrowings during 2009[(b)(c)]	$ -	$ -	$ -	$ 100	$ 135
Peak interest rate during 2009[(b)]	-	-	-	3.25%	3.25%

2007 $500 Million Credit Facility (Terminated)	CIPS	CILCO (Parent)	IP	AERG	Total
2008:					
Average daily borrowings outstanding during 2008	$ -	$ 56	$ 133	$ 95	$ 384
Outstanding credit facility borrowings at period end	-	-	-	85	85
Weighted-average interest rate during 2008	-	4.02%	4.28%	3.95%	4.25%
Peak credit facility borrowings during 2008	$ -	$ 75	$ 200	$ 150	$ 500
Peak interest rate during 2008	-	6.47%	6.15%	6.22%	6.66%

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Calculated through the termination date.
(c) 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 under all credit facilities during 2009 were $1 billion.

The following table summarizes the borrowing activity and relevant interest rates under the 2006 $500 million credit facility, which was terminated during 2009, for the years ended December 31, 2009 and 2008:

2006 $500 Million Credit Facility (Terminated)	CIPS	CILCO (Parent)	IP	AERG	Total[(a)]
2009:					
Average daily borrowings outstanding during 2009[(b)]	$ 5	$ -	$ -	$ 96	$ 150
Outstanding credit facility borrowings at period end	-	-	-	-	-
Weighted-average interest rate during 2009[(b)]	2.02%	-	-	1.34%	1.54%
Peak credit facility borrowings during 2009[(c)(b)]	$ 62	$ -	$ -	$ 151	$ 263
Peak interest rate during 2009[(b)]	2.02%	-	-	2.72%	3 .29%
2008:					
Average daily borrowings outstanding during 2008	$ 58	$ 37	$ 27	$ 151	$ 323
Outstanding credit facility borrowings at period end	62	-	-	151	263
Weighted-average interest rate during 2008	4.21%	3.78%	4.08%	3.94%	4.07%
Peak credit facility borrowings during 2008	$ 135	$ 75	$ 150	$ 200	$ 465
Peak interest rate during 2008	6.31%	5.98%	6.50%	7.01%	7.01%

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Calculated through the termination date.
(c) 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 under all facilities during 2009 were $1 billion.

On June 30, 2009, Ameren and certain of its subsidiaries entered into multiyear credit facility agreements with 24 international, national, and regional lenders, with no single lender providing more than $146 million of credit. These facilities, as described below, cumulatively provide $2.1 billion of credit through July 14, 2010, reducing to $1.8795 billion through June 30, 2011, and to $1.0795 billion through July 14, 2011.

2009 Multiyear Credit Agreements

On June 30, 2009, Ameren, UE, and Genco entered into an agreement (the "2009 Multiyear Credit Agreement") to amend and restate the $1.15 billion five-year revolving credit agreement that was originally entered into on July 14, 2005, amended and restated as of July 14, 2006, and due to expire in July 2010 (the "Prior $1.15 Billion Credit Facility"). Ameren, UE, and Genco also entered into a $150 million Supplemental Credit Agreement to the 2009 Multiyear Credit Agreement (the "Supplemental Agreement"), which provides Ameren, UE, and Genco with an additional facility of $150 million with terms and conditions substantially identical to the 2009 Multiyear Credit Agreement. Collectively, these agreements are the "2009 Multiyear Credit Agreements."

The obligations of each borrower under the 2009 Multiyear Credit Agreements are several and not joint. Except under limited circumstances relating to expenses and indemnities, the obligations of UE or Genco are not guaranteed by Ameren or by any other subsidiary of Ameren. The combined maximum amount available to all of the borrowers, collectively, under the 2009 Multiyear Credit Agreements is $1.3 billion, and the combined maximum amount available to each borrower, individually, under the 2009 Multiyear Credit Agreements is limited as follows: Ameren - $1.15 billion, UE - $500 million and Genco - $150 million (such amounts being each borrower's "Borrowing Sublimit"). CIPS, CILCO and IP have no borrowing authority or liability under the 2009 Multiyear Credit Agreements.

On July 14, 2010, when the Supplemental Agreement terminates, all commitments and all outstanding amounts under the Supplemental Agreement will be consolidated with those under the 2009 Multiyear Credit Agreement, and the combined maximum amount available to all borrowers will be $1.0795 billion. The UE and Genco Borrowing Sublimits will remain as noted above; the Ameren sublimit will change to $1.0795 billion. Ameren has the option of seeking additional commitments from existing or new lenders to increase the total facility size to $1.3 billion after July 14, 2010. The 2009 Multiyear Credit Agreement will terminate with respect to Ameren on July 14, 2011, one year after the Prior $1.15 Billion Credit Facility. The Borrowing Sublimits of UE and Genco will continue to be subject to extensions on a 364-day basis (but in no event later than July 14, 2011). The current maturity date of their Borrower Sublimits under the 2009 Multiyear Credit Agreements is June 29, 2010.

The obligations of all borrowers under the 2009 Multiyear Credit Agreements are unsecured. The interest rates applicable to loans under the 2009 Multiyear Credit Agreements will be either the alternate base rate, as defined, plus the margin applicable to the particular borrower or the eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined by reference to such borrower's long-term unsecured credit ratings in effect at the time. A competitive bid rate is also available if requested by a borrower. Letters of credit in an aggregate undrawn face amount not to exceed $287.5 million are available for issuance for account of the borrowers under the 2009 Multiyear Credit Agreements (but within the $1.3 billion overall combined facility limitation).

Under the 2009 Multiyear Credit Agreements, the principal amount of each revolving loan will be due and payable no later than the final maturity of the agreements, for Ameren, and the last day of the then applicable 364-day period for UE and Genco. Ameren, UE and Genco will use the proceeds of any borrowings under the 2009 Multiyear Credit Agreements for general corporate purposes, including working capital, and to fund loans under the Ameren money pool arrangements.

2009 Illinois Credit Agreement

Also on June 30, 2009, Ameren, CIPS, CILCO, and IP entered into an $800 million multiyear, senior secured credit agreement (the "2009 Illinois Credit Agreement"). The 2009 Illinois Credit Agreement replaced the Ameren Illinois Utilities' $500 million credit facility dated July 14, 2006 (the "2006 $500 Million Credit Facility (Terminated)"), and their $500 million credit facility dated February 9, 2007 (the "2007 $500 Million Credit Facility (Terminated)"), each as previously amended (collectively, the "Terminated Illinois Credit Facilities"). They were terminated when the 2009 Illinois Credit Agreement went into effect.

Ameren was not a borrower under the Terminated Illinois Credit Facilities, but it is a borrower under the 2009 Illinois Credit Agreement. AERG was a borrower under the Terminated Illinois Credit Facilities, but it was not party to or a borrower under the 2009 Illinois Credit Agreement. All obligations of AERG under the Terminated Illinois Credit Facilities have been repaid, and all liens securing such obligations have been released. AERG expects to meet its external liquidity needs through borrowings under the Ameren non-state-regulated subsidiary money pool arrangements or other liquidity arrangements.

The obligations of each borrower under the 2009 Illinois Credit Agreement are several and not joint. They are not guaranteed by Ameren or any other subsidiary of Ameren. The maximum amount available to each borrower under the facility is limited as follows: Ameren - $300 million, CIPS - $135 million, CILCO - $150 million and IP - $350 million (such amounts being such borrower's "Borrowing Sublimit").

The 2009 Illinois Credit Agreement will terminate with respect to all borrowers on June 30, 2011. Each borrowing under the 2009 Illinois Credit Agreement must be repaid no later than 364 days after such borrowing. In each case, the borrower may on such date make a new borrowing, or convert or continue such borrowing as a new borrowing subject to satisfaction of the applicable conditions. The obligations of the Ameren Illinois Utilities under the 2009 Illinois Credit Agreement are secured by the issuance of mortgage bonds, for collateral support, by each such utility under its respective mortgage indenture, in an amount equal to its respective Borrowing Sublimit. Ameren's obligations are unsecured.

Loans are available on a revolving basis under the 2009 Illinois Credit Agreement. They 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 applicable under the 2009 Illinois Credit Agreement are the alternate base rate, as defined, plus the margin applicable to the particular borrower or the eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined, in the case of Ameren, by Ameren's long-term unsecured credit ratings in effect, at the time, and in the case of the Ameren Illinois Utilities, such utility's long-term secured credit ratings at the time. Letters of credit in an aggregate undrawn face amount not to exceed $200 million are also available for issuance for the account of the borrowers under the 2009 Illinois Credit Agreement (but within the $800 million overall facility limitation).

Due to outstanding borrowings under the 2009 Multiyear Credit Agreements and the 2009 Illinois Credit Agreement (including reductions for $15 million of letters of credit issued under the 2009 Multiyear Credit Agreements), the available amounts under the facilities at December 31, 2009, were $555 million and $700 million, respectively.

Other Agreements

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.

On June 25, 2008, Ameren entered into a $300 million term loan agreement due June 24, 2009, which was fully drawn on June 26, 2008. The average annual interest rate for borrowing under the $300 million term loan agreement was 1.97% during the period it was outstanding in 2009. This term loan was repaid at maturity in June 2009 with proceeds from the issuance by Ameren of $425 million principal amount of senior unsecured notes due May 2014. See Note 5 - Long-term Debt and Equity Financings.

Indebtedness Provisions and Other Covenants

The 2009 Multiyear 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. The 2009 Multiyear Credit Agreements also contain nonfinancial covenants, including restrictions on the ability to incur liens, to transact with affiliates, to dispose of assets, and to merge with other entities. In addition, Ameren and certain subsidiaries are restricted to limited investments in and other transfers to affiliates, including investments in the Ameren Illinois Utilities and their subsidiaries.

The 2009 Multiyear Credit Agreements contain identical default provisions including a cross default of a borrower to the occurrence of a default by such borrower under any other agreement covering indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries and non-material subsidiaries) in excess of $25 million in the aggregate. A default by an Ameren Illinois utility under the 2009 Illinois Credit Agreement does not constitute a default under the 2009 Multiyear Credit Agreements. Any default of Ameren under the 2009 Illinois Credit Agreement that occurs solely as a result of a default by an Ameren Illinois utility thereunder will not constitute a default under either of the 2009 Multiyear Credit Agreements while Ameren is otherwise in compliance with all of its obligations under the 2009 Illinois Credit Agreement.

The 2009 Multiyear Credit Agreements require Ameren, UE and Genco each to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a calculation set forth in the facilities. All of the consolidated subsidiaries of Ameren, including the

Ameren Illinois Utilities, are included for purposes of determining compliance with this capitalization test with respect to Ameren. Failure to satisfy the capitalization covenant constitutes a default under the 2009 Multiyear Credit Agreements. As of December 31, 2009, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the 2009 Multiyear Credit Agreements, were 51%, 48% and 54%, for Ameren, UE and Genco, respectively.

The 2009 Illinois Credit Agreement contains conditions to borrowings and issuance of letters of credit, including the absence of default or unmatured default, material accuracy of representations and warranties (excluding, for so long as ratings conditions shall be satisfied, any representation after the closing date as to the absence of material adverse change and material litigation, which is new to the 2009 Illinois Credit Agreement), and required regulatory authorizations. The rating condition is satisfied if the borrower has a Moody's rating of Baa3 or higher or an S&P rating of BBB- or higher (in the case of Ameren, with respect to senior unsecured long-term debt, and in the case of the Ameren Illinois Utilities, with respect to senior secured long-term debt). The 2009 Illinois Credit Agreement contains nonfinancial covenants, including restrictions on the ability to incur liens, to transact with affiliates, to dispose of assets, and to merge with other entities. The Ameren Illinois Utilities may engage in certain mergers or similar transactions that may cause their utility operations to be conducted by a single legal entity. In addition, the 2009 Illinois Credit Agreement has nonfinancial covenants that limit the ability of a borrower to invest in or to transfer assets to affiliates, covenants regarding the status of the collateral securing the 2009 Illinois Credit Agreement, and maintenance of the validity of the security interests therein.

The 2009 Illinois Credit Agreement contains default provisions. Defaults under the 2009 Illinois Credit Agreement apply separately to each borrower; provided that a default by an Ameren Illinois utility will constitute a default by Ameren. Defaults include a cross default of a borrower to the occurrence of a default by such borrower under any other agreement covering indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries and non-material subsidiaries) in excess of $25 million in the aggregate. A default by Genco or UE under the 2009 Multiyear Credit Agreements does not constitute an event of default under the 2009 Illinois Credit Agreement. Any default of Ameren under the 2009 Multiyear Credit Agreements that occurs solely as a result of a default by UE or Genco thereunder will not constitute a default under the 2009 Illinois Credit Agreement while Ameren is otherwise in compliance with all of its obligations under the 2009 Multiyear Credit Agreements. Furthermore, under the 2009 Illinois Credit Agreement, the occurrence of a default resulting from an event or conditions effecting AERG shall be deemed to constitute a default with respect to Ameren under the 2009 Illinois Credit Agreement, but shall not in itself constitute a default with respect to CILCO, unless the liability that CILCO has for such default or such underlying event or condition giving rise to such default would otherwise constitute a default with respect to CILCO if the underlying event or condition had occurred or existed at CILCO.

The 2009 Illinois Credit Agreement requires Ameren and each Ameren Illinois utility to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a defined calculation. All of the consolidated subsidiaries of Ameren are included for purposes of determining compliance with this capitalization test with respect to Ameren. As of December 31, 2009, the ratios of consolidated indebtedness to total consolidated capitalization for Ameren, CIPS, CILCO and IP, calculated in accordance with the provisions of the 2009 Illinois Credit Agreement, were 51%, 44%, 41%, and 46%, respectively. In addition, Ameren is required to maintain a ratio of consolidated funds from operations plus interest expense to consolidated interest expense of 2.0 to 1, at the end of the most recent four fiscal quarters, calculated and subject to adjustment in accordance with the 2009 Illinois credit agreement. Ameren's ratio as of December 31, 2009, was 4.6 to 1. Failure to satisfy these covenants constitutes a default under the 2009 Illinois Credit Agreement.

In addition, the 2009 Illinois Credit Agreement prohibits CILCO from issuing any preferred stock if, after such issuance, the aggregate liquidation value of all CILCO preferred stock issued after June 30, 2009, would exceed $50 million.

None of Ameren's credit facilities or financing arrangements contain credit rating triggers that would cause default or acceleration of repayment of outstanding balances. At December 31, 2009, management believes that the Ameren Companies were in compliance with their credit facilities and term loan agreement 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. CIPS, CILCO and IP borrow from each other through the utility money pool agreement subject to applicable regulatory short-term borrowing authorizations. Ameren Services administers the utility money pool and tracks internal and external funds separately. Ameren and AERG 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 source of external funds for the utility money pool are the 2009 Multiyear Credit Agreements and the 2009 Illinois Credit Agreement. 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. CIPS, CILCO and IP rely on the utility money pool to coordinate and provide for certain short-term cash and working capital requirements. Borrowers 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, 2009, was 0.19% (2008 - 2.85%).

Non-state-regulated Subsidiaries

Ameren Services, Resources Company, Genco, AERG, Marketing Company, AFS, 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 2009 Multiyear 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 2009 Multiyear Credit Agreements at December 31, 2009. 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. Borrowers 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. These rates are based on the cost of funds used for money pool advances. The average interest rate for borrowing under the non-state-regulated subsidiary money pool for the year ended December 31, 2009 was 1.64% (2008 - 3.51%).

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, 2009, 2008, and 2007.

In addition, a unilateral borrowing agreement exists between Ameren, IP, and Ameren Services, which enables IP to make short-term borrowings directly from Ameren. The aggregate amount of borrowings outstanding at any time by IP under the unilateral borrowing agreement and the utility money pool agreement, together with any outstanding external credit facility borrowings by IP, may not exceed $500 million, pursuant to authorization from the ICC. IP is not currently borrowing under the unilateral borrowing agreement. Ameren Services is responsible for operation and administration of the unilateral borrowing agreement.

NOTE 5 - LONG-TERM DEBT AND EQUITY FINANCINGS

The following table presents long-term debt outstanding for the Ameren Companies as of December 31, 2009 and 2008:

	2009	2008
Ameren (Parent):		
8.875% Senior unsecured notes due 2014	**$ 425**	$ -
Less: Unamortized discount and premium	**(2)**	-
Long-term debt, net	**$ 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[c]	**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**	-
Environmental improvement and pollution control revenue bonds: [a][b][c][d]		
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[e]	**66**	66
Capital lease obligations:		
City of Bowling Green capital lease (Peno Creek CT)	**78**	82
Audrain County capital lease (Audrain County CT)	**240**	240
Total long-term debt, gross	**4,030**	3,684
Less: Unamortized discount and premium	**(8)**	(7)
Less: Maturities due within one year	**(4)**	(4)
Long-term debt, net	**$ 4,018**	$ 3,673
CIPS:		
First mortgage bonds:[a]		
6.625% Senior secured notes due 2011[b]	**$ 150**	$ 150
7.61% Series 1997-2 due 2017	**40**	40
6.125% Senior secured notes due 2028[b]	**60**	60
6.70% Senior secured notes due 2036[b]	**61**	61
Environmental improvement and pollution control revenue bonds:		
2000 Series A 5.50% due 2014	**51**	51
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[d]	**17**	17
Total long-term debt, gross	**422**	422
Less: Unamortized discount and premium	**(1)**	(1)
Long-term debt, net	**$ 421**	$ 421
Genco:		
Unsecured notes:		
Senior notes Series D 8.35% due 2010	**$ 200**	$ 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**	-
Total long-term debt, gross	**1,025**	775
Less: Unamortized discount and premium	**(2)**	(1)
Less: Maturities due within one year	**(200)**	-
Long-term debt, net	**$ 823**	$ 774

	2009	**2008**
CILCORP (Parent):		
Unsecured notes:		
8.70% Senior notes due 2009	**$ -**	$ 124
9.375% Senior bonds due 2029	**2**	210
Fair-market value adjustments	**-**	49
Total long-term debt, gross	**2**	383
Less: Maturities due within one year	**-**	(126)
Long-term debt, net	**$ 2**	$ 257
CILCO:		
First mortgage bonds:[a]		
8.875% Senior secured notes due 2013[b]	**$ 150**	$ 150
6.20% Senior secured notes due 2016[b]	**54**	54

6.70% Senior secured notes due 2036(b)	**42**	42
Environmental improvement and pollution-control revenue bonds:(a)(c)		
6.20% Series 1992B due 2012	**1**	1
5.90% Series 1993 due 2023	**32**	32
Long-term debt, net	**$ 279**	$ 279
IP:		
Mortgage bonds:(a)		
7.50% Series due 2009	**$ -**	$ 250
6.25% Senior secured notes due 2016(b)	**75**	75
6.125% Senior secured notes due 2017(b)	**250**	250
6.250% Senior secured notes due 2018(b)	**337**	337
9.750% Senior secured notes due 2018(b)	**400**	400
Pollution control revenue bonds:(a)(c)		
5.70% 1994A Series due 2024	**36**	36
5.40% 1998A Series due 2028	**19**	19
5.40% 1998B Series due 2028	**33**	33
Fair-market value adjustments	**6**	10
Total long-term debt, gross	**1,156**	1,410
Less: Unamortized discount and premium	**(9)**	(10)
Less: Maturities due within one year	**-**	(250)
Long-term debt, net	**$ 1,147**	$ 1,150
Ameren consolidated long-term debt, net	**$ 7,113**	$ 6,554

(a) At December 31, 2009, most property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued. Substantially all of the long-term debt issued by UE, CIPS (excluding the tax-exempt debt), CILCO and IP is secured by a lien on substantially all of its property and franchises.

(b) These notes are collaterally secured by first mortgage bonds issued by UE, CIPS, CILCO, or IP, respectively, 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 101% of par, declining to 100% of par in October 2010), 6.00% Series due 2018, and 6.70% Series due 2019; CIPS - 7.61% Series 1997-2 due 2017 (currently callable at 102.28% of par, declining annually thereafter to 100% of par in June 2012); CILCO - 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; IP - 6.125% Series due 2017, 6.25% Series due 2018, 9.75% Series due 2018, and all IP pollution control revenue bonds.

(c) Environmental improvement or pollution control series secured by first mortgage bonds. In addition, all of the series except UE's 5.45% Series and CILCO's 6.20% Series 1992B and 5.90% Series 1993 bonds are backed by an insurance guarantee policy.

(d) 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 2009 and 2008 were as follows:

	2009	2008
UE 1992 Series	0.68%	3.66%
UE 1998 Series A	0.99%	3.97%
UE 1998 Series B	1.02%	3.71%
UE 1998 Series C	0.99%	4.06%
CIPS 1993 Series B-1	1.34%	1.98%

(e) Under the terms of the subordinated debentures, UE may, under certain circumstances, defer the payment of interest for up to five years. If UE should elect to defer interest payments, UE dividend payments to Ameren would be prohibited. UE has not elected to defer any interest payments.

The following table presents the aggregate maturities of long-term debt, including current maturities, for the Ameren Companies at December 31, 2009:

	Ameren(Parent)(a)	UE(a)	CIPS(a)	Genco(a)(b)	CILCORP (Parent)	CILCO	IP(a)(c)	Ameren Consolidated
2010	$ -	$ 4	$ -	$ 200	$ -	$ -	$-	$ 204
2011	-	5	150	-	-	-	-	155
2012	-	178	-	-	-	1	-	179
2013	-	205	-	-	-	150	-	355
2014	425	109	51	-	-	-	-	585
Thereafter	-	3,529	221	825	2	128	1,150	5,855
Total	$ 425	$ 4,030	$ 422	$ 1,025	$ 2	$ 279	$1,150	$ 7,333

(a) Excludes unamortized discount and premium of $2 million, $8 million, $1 million, $2 million, and $9 million at Ameren (Parent), UE, CIPS, Genco, and IP, respectively.
(b) Excludes $45 million due in 2010 related to a note payable to an affiliate. See Note 14 - Related Party Transactions for additional information.
(c) Excludes $6 million related to IP'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, CIPS, Genco, CILCO and IP, 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 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.

The following table presents information with respect to the Form S-3 shelf registration statements filed and effective for certain Ameren Companies as of December 31, 2009:

	Effective Date	Authorized Amount
Ameren	November 2008	Not limited
UE	June 2008	Not limited
CIPS	November 2008	Not limited
Genco	November 2008	Not limited
CILCO	November 2008	Not limited
IP	November 2008	Not limited

Ameren

In July 2008, Ameren filed a Form S-3 registration statement with the SEC 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 3.2 million, 4.0 million, and 1.7 million shares of common stock in 2009, 2008, and 2007, respectively, which were valued at $82 million, $154 million, and $91 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, providing 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 as follows: UE - $436 million, CIPS - $13 million, CILCO - $25 million, and IP - $61 million.

UE

In April 2008, UE issued $250 million of 6.00% senior secured notes due April 1, 2018, with interest payable semiannually on April 1 and October 1 of each year, beginning in October 2008. These notes are secured by first mortgage bonds. UE received net proceeds of $248 million, which were used to redeem certain of UE's outstanding auction-rate environmental improvement revenue refunding bonds discussed below and to repay short-term debt. In connection with this issuance of $250 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 April 2008, $63 million of UE's Series 2000B auction-rate environmental improvement revenue refunding bonds were redeemed at par value plus accrued interest.

In May 2008, $43 million of UE's Series 1991, $64 million of UE's Series 2000A and $60 million of UE's Series 2000C auction-rate environmental improvement revenue refunding bonds were redeemed at par value plus accrued interest. Also, in May 2008, $148 million of UE's 6.75% Series first mortgage bonds matured and were retired.

In June 2008, UE issued $450 million of 6.70% senior secured notes due February 1, 2019, with interest payable semiannually on February 1 and August 1 of each year, beginning in February 2009. These notes are secured by first mortgage bonds. UE received net proceeds of $446 million, which was used to repay short-term debt. A portion of that debt had been incurred so that UE could pay at maturity the 6.75% Series first mortgage bonds noted above. In connection with this issuance of $450 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. The first mortgage bond release date is the date at which the security provided by the pledge under UE's first mortgage indenture would no longer be available to holders of any outstanding series of its senior secured notes and such indebtedness would become senior unsecured indebtedness.

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.

CIPS

In April 2008, $35 million of CIPS' Series 2004 auction-rate environmental improvement revenue refunding bonds were redeemed at par value plus accrued interest.

In December 2008, $15 million of CIPS' 5.375% senior secured notes matured and were retired.

Genco

In April 2008, Genco issued and sold, with registration rights in a private placement, $300 million of 7.00% senior unsecured notes due April 15, 2018, with interest payable semiannually on April 15 and October 15 of each year, beginning in October 2008. Genco received net proceeds of $298 million, which was used to fund capital expenditures, to repay short-term debt, and for other general corporate purposes. Genco exchanged the outstanding unregistered unsecured notes for registered unsecured notes in July 2008.

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.

CILCORP

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 $2.7 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.

CILCO

In April 2008, $19 million of CILCO's Series 2004 auction-rate environmental improvement revenue refunding bonds were redeemed at par value plus accrued interest.

In July 2008, CILCO redeemed the remaining 165,000 shares of its 5.85% Class A preferred stock at a redemption price of $100 per share plus accrued and unpaid dividends. The redemption completed CILCO's mandatory redemption obligations for this series of preferred stock.

In December 2008, CILCO issued $150 million of 8.875% senior secured notes due December 15, 2013, with interest payable semiannually on June 15 and December 15 of each year, beginning in June 2009. These notes are secured by first mortgage bonds. CILCO received net proceeds of

$149 million, which were used to repay short-term borrowings. In connection with this issuance of $150 million of senior secured notes, CILCO 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. The mortgage bond release date is the date at which the security provided by the pledge under CILCO's first mortgage indenture would no longer be available to holders of any outstanding series of its senior secured notes and such indebtedness would become senior unsecured indebtedness.

IP

In April 2008, IP issued and sold, with registration rights in a private placement, $337 million of 6.25% senior secured notes due April 1, 2018, with interest payable semiannually on April 1 and October 1 of each year, beginning in October 2008. IP received net proceeds of $334 million, which were used to redeem all of IP's outstanding auction-rate pollution control revenue refunding bonds during May and June 2008, as discussed below. In connection with IP's April 2008 issuance of $337 million of senior secured notes, IP 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. The mortgage bond release date is the date at which the security provided by the pledge under IP's first mortgage indenture would no longer be available to holders of any outstanding series of its senior secured notes and such indebtedness would become senior unsecured indebtedness. IP exchanged the outstanding unregistered secured notes for registered secured notes in June 2008.

In May 2008, IP redeemed its $112 million Series 2001 Non-AMT, $75 million Series 2001 AMT, $70 million 1997 Series A, and $45 million 1997 Series B auction-rate pollution control revenue bonds at par value plus accrued interest. In June 2008, IP redeemed its $35 million 1997 Series C auction-rate pollution control revenue bonds at par value plus accrued interest.

In September 2008, IP redeemed the remaining portion of its $54 million principal amount 5.65% note payable to IP SPT. Previous redemptions occurred in the first and second quarters of 2008 for $19 million and $20 million, respectively. This was the remaining outstanding amount of $864 million of TFNs issued by the IP SPT in December 1998.

In October 2008, IP issued and sold, with registration rights in a private placement, $400 million of 9.75% senior secured notes due November 15, 2018, with interest payable semiannually on November 15 and May 15 of each year, beginning in May 2009. IP received net proceeds of $391 million, which were used to repay short-term debt. In connection with IP's October 2008 issuance of $400 million of senior secured notes, IP 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 February 2009, IP commenced an offer to exchange the outstanding unregistered secured notes for registered secured notes. In March 2009, IP exchanged all $400 million of its unregistered 9.75% senior secured notes for a like amount of registered 9.75% senior secured notes due November 15, 2018.

In June 2009, $250 million of IP's 7.50% series first mortgage bonds matured and were retired.

Indenture Provisions and Other Covenants

UE's, CIPS', CILCO's and IP's indenture provisions and articles of incorporation include covenants and provisions related to issuances of first mortgage bonds and preferred stock. UE, CIPS, CILCO and IP 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, 2009, at an assumed interest 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	=2.0	2.9	$ 1,255	=2.5	44.6	$ 1,251
CIPS	=2.0	4.2	344	=1.5	2.0	114
CILCO	=2.0(d)	7.6	214	=2.5	155.0	50(e)
IP	=2.0	3.6	1,191	=1.5	1.8	244

(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 $95 million, $18 million, $44 million, and $536 million, at UE, CIPS, CILCO and IP, respectively.

(c) Coverage required on the annual interest charges on all long-term debt (CIPS only) and the annual dividend on preferred stock outstanding and to be issued, as required in the respective company's articles of incorporation. For CILCO, this ratio must be met for a period of 12 consecutive calendar months within the 15 months immediately preceding the issuance.

(d) In lieu of meeting the interest coverage ratio requirement, CILCO may attempt to meet an earnings requirement of at least 12% of the principal amount of all mortgage bonds outstanding and to be issued. For the 12 months ended December 31, 2009, CILCO had earnings equivalent to at least 38% of the principal amount of all mortgage bonds outstanding.

(e) See Note 4 - Credit Facility Borrowings and Liquidity for a discussion regarding a restriction on the issuances of preferred stock by CILCO.

UE, CIPS, Genco, CILCO and IP 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, CIPS, CILCO and IP 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 CIPS, CILCO or IP 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 $1.8 billion of free and unrestricted retained earnings at December 31, 2009.

CIPS' articles of incorporation and mortgage indentures 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.

CILCO's articles of incorporation prohibit the payment of dividends on its common stock from either paid-in surplus or any surplus created by a reduction of stated capital or capital stock. Dividend payment is also prohibited if at the time of dividend declaration the earned surplus account (after deducting the payment of such dividends) would not contain an amount at least equal to two times the annual dividend requirement on all outstanding shares of CILCO's preferred stock.

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 December 31, 2009:

	Required Interest Coverage Ratio	Actual Interest Coverage Ratio	Required Debt-to-Capital Ratio	Actual Debt-to-Capital Ratio
Genco (a)	=1.75(b)	5.62	=60%	52%

(a) Interest coverage ratio relates to covenants about certain dividend, principal, and interest payments on certain subordinated intercompany borrowings. The debt-to-capital ratio relates to a debt incurrence covenant, which also requires an interest coverage ratio of 2.5 for the four fiscal quarters most recently ended.

(b) Ratio excludes amounts payable under Genco's intercompany note to CIPS. The ratio must be met both for the prior four fiscal quarters and for the succeeding four six-month periods.

Genco's debt incurrence-related ratio restrictions and restricted payment limitations 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, 2009, 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.

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, 2009, 2008, and 2007:

	2009	2008	2007
Ameren:(a)			
Miscellaneous income:			
Interest and dividend income	**$ 2**	$ 15	$ 27
Interest income on industrial development revenue bonds	**28**	28	28
Allowance for equity funds used during construction	**36**	28	5
Other	**5**	9	15
Total miscellaneous income	**$ 71**	$ 80	$ 75
Miscellaneous expense:			
Donations	**$ (12)**	$ (13)	$ (13)

	2009	2008	2007
Other	**(11)**	(18)	(12)
Total miscellaneous expense	**$ (23)**	$ (31)	$ (25)
UE:			
Miscellaneous income:			
Interest and dividend income	**$ 1**	$ 5	$ 4
Interest income on industrial development revenue bonds	**28**	28	28
Allowance for equity funds used during construction	**33**	28	4
Other	**1**	1	2
Total miscellaneous income	**$ 63**	$ 62	$ 38
Miscellaneous expense:			
Donations	**$ (3)**	$ (3)	$ (2)
Other	**(4)**	(6)	(5)
Total miscellaneous expense	**$ (7)**	$ (9)	$ (7)
CIPS:			
Miscellaneous income:			
Interest and dividend income	**$ 5**	$ 9	$ 16
Other	**3**	2	1
Total miscellaneous income	**$ 8**	$ 11	$ 17
Miscellaneous expense:			
Donations	**$ (1)**	$ (2)	$ (2)
Other	**(1)**	(1)	(1)
Total miscellaneous expense	**$ (2)**	$ (3)	$ (3)
Genco:			
Miscellaneous income:			
Interest and dividend income	**$ -**	$ 1	$ -
Total miscellaneous income	**$ -**	$ 1	$ -
Miscellaneous expense:			
Other	**$ -**	$ (1)	$ -
Total miscellaneous expense	**$ -**	$ (1)	$ -
CILCO:			
Miscellaneous income:			
Interest and dividend income	**$ 1**	$ 1	$ 4
Other	**-**	1	1
Total miscellaneous income	**$ 1**	$ 2	$ 5
Miscellaneous expense:			
Donations	**$ (1)**	$ (2)	$ (1)
Other	**(4)**	(3)	(5)
Total miscellaneous expense	**$ (5)**	$ (5)	$ (6)
IP:			
Miscellaneous income:			
Interest and dividend income	**$ -**	$ 5	$ 8
Allowance for equity funds used during construction	**2**	-	-
Other	**1**	6	6
Total miscellaneous income	**$ 3**	$ 11	$ 14
Miscellaneous expense:			
Donations	**$ (2)**	$ (3)	$ (3)
Other	**(1)**	(2)	(2)
Total miscellaneous expense	**$ (3)**	$ (5)	$ (5)

(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 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, 2009:

	Quantity			
Commodity	**NPNS Contracts(a)**	**Cash Flow Hedges(b)**	**Other Derivatives(c)**	**Derivatives Subject to Regulatory Deferral(d)**
Coal (in tons)				
Ameren(e)	114,747,000	(f)	(f)	(f)
UE	80,540,000	(f)	(f)	(f)
Genco	17,403,000	(f)	(f)	(f)
CILCO	7,782,000	(f)	(f)	(f)
Natural gas (in mmbtu)				
Ameren(e)	164,843,000	(f)	28,104,000	136,266,000
UE	21,683,000	(f)	5,390,000	20,730,000
CIPS	27,625,000	(f)	(f)	22,228,000
Genco	(f)	(f)	7,383,000	(f)
CILCO	49,580,000	(f)	(f)	36,368,000
IP	65,956,000	(f)	(f)	56,941,000
Heating oil (in gallons)				
Ameren(e)	(f)	(f)	94,254,000	117,300,000
UE	(f)	(f)	(f)	117,300,000
Genco	(f)	(f)	48,126,000	(f)
CILCO	(f)	(f)	21,286,000	(f)
Power (in megawatthours)				
Ameren(e)	75,948,000	32,136,000	22,182,000	35,871,000
UE	3,579,000	(f)	608,000	4,071,000
CIPS	(f)	(f)	(f)	10,494,000
CILCO	(f)	(f)	(f)	5,406,000
IP	(f)	(f)	(f)	15,900,000
Uranium (in pounds)				
Ameren	(f)	(f)	(f)	250,000
UE	(f)	(f)	(f)	250,000

(a) Contracts through December 2013, March 2015, and September 2035 for coal, natural gas, and power, respectively.
(b) Contracts through December 2012 for power.
(c) Contracts through April 2012, December 2013, and May 2013 for natural gas, heating oil, and power, respectively.
(d) Contracts through October 2015, December 2013, December 2012, and November 2011 for natural gas, heating oil, power, and uranium, respectively.
(e) Includes amounts from Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(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.

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 classification of all derivative instruments as of December 31, 2009:

	Balance Sheet Location	Ameren(a)	UE	CIPS	Genco	CILCO	IP
Derivative assets designated as hedging instruments							
Commodity contracts:							
Power	MTM derivative assets	$ 20	$ -	$ (b)	$ (b)	$ (b)	$ (b)
	Other assets	4	-	-	-	-	-
	Total assets	$ 24	$ -	$ -	$ -	$ -	$ -
Derivative liabilities designated as hedging instruments							
Commodity contracts:							
Power	MTM derivative liabilities	$ 1	$ (b)	$ -	$ (b)	$ -	$ -
	Total liabilities	$ 1	$ -	$ -	$ -	$ -	$ -
Derivative assets not designated as hedging instruments							
Commodity contracts:							
Natural gas	MTM derivative assets	$ 19	$ 2	$ (b)	$ (b)	$ (b)	$ (b)
	Other current assets	-	-	1	-	2	1
	Other assets	4	-	-	-	1	1
Heating oil	MTM derivative assets	39	22	(b)	(b)	(b)	(b)
	Other current assets	-	-	-	9	4	-
	Other assets	41	23	-	9	4	-
Power	MTM derivative assets	43	7	(b)	(b)	(b)	(b)
	Other assets	10	-	-	-	-	-
	Total assets	$ 156	$ 54	$ 1	$ 18	$ 11	$ 2
Derivative liabilities not designated as hedging instruments							
Commodity contracts:							
Natural gas	MTM derivative liabilities	$ 55	$ (b)	$ 8	$ (b)	$ 7	$ 17
	Other current liabilities	-	10	-	1	-	-
	Other deferred credits and liabilities	44	6	8	-	8	19
Heating oil	MTM derivative liabilities	15	(b)	-	(b)	2	-
	Other current liabilities	-	9	-	3	-	-
	Other deferred credits and liabilities	5	3	-	1	-	-
Power	MTM derivative liabilities	37	(b)	2	(b)	1	3
	MTM derivative liabilities - affiliates	(b)	(b)	43	(b)	19	65
	Other current liabilities	-	8	-	-	-	-
	Other deferred credits and liabilities	4	-	95	-	49	145
Uranium	MTM derivative liabilities	1	(b)	-	(b)	-	-

Other current liabilities	-	1	-	-	-	-
Other deferred credits and liabilities	1	1	-	-	-	-
Total liabilities	$ 162	$ 38	$ 156	$ 5	$ 86	$ 249

(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, 2009 and 2008:

	Ameren(a)	UE	CIPS	Genco	CILCO	IP
2009:						
Cumulative gains (losses) deferred in accumulated OCI:						
Power forwards(b)	**$ 24**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Interest rate swaps(c)(d)	**(10)**	**-**	**-**	**(10)**	**-**	**-**
Cumulative gains (losses) deferred in regulatory liabilities or assets:						
Natural gas swaps, forwards and futures contracts(e)	**(75)**	**(13)**	**(15)**	**-**	**(12)**	**(34)**
Power forwards(f)	**(10)**	**(1)**	**(140)**	**-**	**(69)**	**(213)**
Heating oil options and swaps(g)	**5**	**5**	**-**	**-**	**-**	**-**
Uranium swaps(h)	**(2)**	**(2)**	**-**	**-**	**-**	**-**

	Ameren(a)	UE	CIPS	Genco	CILCO	IP
2008:						
Cumulative gains (losses) deferred in accumulated OCI:						
Power forwards(b)	$ 84	$ 40	$ -	$ -	$ -	$ -
Interest rate swaps(c)(d)	(11)	-	-	(11)	-	-
Cumulative losses deferred in regulatory assets:						
Natural gas swaps, forwards and futures contracts(e)	(118)	(16)	(27)	-	(25)	(50)
Power forwards(f)	-	-	(56)	-	(29)	(85)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Represents net gains associated with power forwards at Ameren as of December 31, 2009. The power forwards are a partial hedge of electricity price exposure through August 2012 as of December 31, 2009. Current gains of $22 million and $123 million were recorded at Ameren as of December 31, 2009 and 2008, respectively. UE recorded current gains of $39 million as of December 31, 2008.
(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, 2009 and 2008, was $1 million and $2 million, respectively. Over the next twelve months, $0.7 million of the gain will be amortized.
(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, 2009 and 2008, was a loss of $11 million and $13 million, respectively. Over the next twelve months, $1.4 million of the loss will be amortized.
(e) Represents net losses associated with natural gas swaps, forwards and futures contracts. The swaps, forwards and futures contracts are a partial hedge of natural gas requirements through October 2014 at IP, through March 2015 at UE and CIPS, and through October 2015 at CILCO, in each case as of December 31, 2009. Current gains deferred as regulatory liabilities include $1 million, $1 million, $2 million, and $1 million at UE, CIPS, CILCO and IP, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $8 million, $8 million, $7 million, and $17 million at UE, CIPS, CILCO and IP, respectively, as of December 31, 2009. Current gains deferred as regulatory liabilities include $10 million, $16 million, $17 million, and $36 million at UE, CIPS, CILCO and IP, respectively, as of December 31, 2008.
(f) Represents net losses associated with power forwards. The power forwards are a partial hedge of power price exposure through December 2011 at UE and December 2012 at CIPS, CILCO and IP, in each case as of December 31, 2009. Current gains deferred as regulatory liabilities include $5 million at UE as of December 31, 2009. Current losses deferred as regulatory assets include $6 million, $45 million, $20 million, and $68 million at UE, CIPS, CILCO and IP, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $14 million, $7 million, and $21 million at CIPS, CILCO and IP, respectively, as of December 31, 2008.
(g) Represents net gains on heating oil options and swaps at UE. The options and swaps are a partial hedge of our transportation costs for coal through December 2013 as of December 31, 2009. 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.
(h) Represents net losses on uranium swaps at UE. The swaps are a partial hedge of our uranium requirements through November 2011 as of December 31, 2009. 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) 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) 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, 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	Electric Utilities	Financial Companies	Commodity Marketing Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
Ameren(b)	$ 517	$ 9	$ 23	$ 123	$ 16	$ 165	$ 11	$ 63	$ 927
UE	-	5	7	30	2	22	-	-	66
CIPS	-	-	-	1	-	-	-	-	1
Genco	-	2	2	3	1	-	6	-	14
CILCO	-	1	-	3	-	-	-	-	4
IP	-	-	-	2	-	-	1	-	3

(a) Primarily comprised of Marketing Company's exposure to Ameren Illinois Utilities related to financial contracts. The exposure is not eliminated at the consolidated Ameren level as it is calculated without regard to the offsetting affiliate counterparty's liability position. See Note 14 - Related Party Transactions 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, 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(a)	Coal Producers	Electric Utilities	Financial Companies	Commodity Marketing Companies	Municipalities/ Cooperatives	Oil and Gas	Retail Companies	Total
Ameren(a)	$ -	$ -	$ -	$ 7	$ 3	$ -	$ -	$ -	$ 10

(a) Represents amounts held by Marketing Company. As of December 31, 2009, Ameren registrant subsidiaries held no cash collateral.

The potential loss on counterparty exposures is reduced by all collateral held and the application of master trading and netting agreements. Collateral includes both cash collateral and other collateral held. Other collateral consisted of letters of credit in the amount of $32 million, $1 million and $1 million held by Ameren, UE and Genco, respectively, as of December 31, 2009. The following table presents the potential loss after consideration of collateral and application of master trading and netting agreements as of December 31, 2009:

	Affiliates(a)	Coal Producers	Electric Utilities	Financial Companies	Commodity Marketing Companies	Municipalities/ Coopatives	Oil and Gas	Retail Companies	Total
Ameren(b)	$ 515	$ -	$ 11	$ 93	$ 3	$ 132	$ 10	$ 61	$ 825
UE	-	-	5	26	1	21	-	-	53
CIPS	-	-	-	-	-	-	-	-	-
Genco	-	-	2	-	-	-	5	-	7
CILCO	-	-	-	1	-	-	-	-	1
IP	-	-	-	-	-	-	1	-	1

(a) Primarily comprised of Marketing Company's exposure to Ameren Illinois Utilities related to financial contracts. The exposure is not eliminated at the consolidated Ameren level as it is calculated without regard to the offsetting affiliate counterparty's liability position. See Note 14 - Related Party Transactions for additional information on these financial contracts.
(b) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

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, 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 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, 2009, and (2) those counterparties with rights to do so requested collateral:

	Aggregate Fair Value of Derivative Liabilities[a]	Cash Collateral Posted	Aggregate Amount of Additional Collateral Required[b]
Ameren[c]	$ 500	$ 61	$ 367
UE	151	8	129
CIPS	41	3	29
Genco	60	-	48
CILCO	56	-	44
IP	71	11	52

(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 determined 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 associated with derivative instruments designated as cash flow hedges for the year ended December 31, 2009:

Derivatives in Cash Flow Hedging Relationship	Amount of Gain (Loss) Recognized in OCI on Derivatives[a]	Location of (Gain) Loss Reclassified from Accumulated OCI into Income[b]	Amount of (Gain) Loss Reclassified from Accumulated OCI into Income[b]	Location of Gain (Loss) Recognized in Income on Derivatives[c]	Amount of Gain (Loss) Recognized in Income on Derivatives[c]
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 from Ameren registrants 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.

Other Derivatives

The following table represents the net change in market value associated with derivatives not designated as hedging instruments for the year ended December 31, 2009:

	Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives
Ameren[a]	Natural gas (generation)	Operating Expenses - Fuel	$ 5
	Natural gas (resale)	Operating Revenues - Gas	6
	Heating oil	Operating Expenses - Fuel	52
	Power	Operating Revenues - Electric	(25)
	SO_2 emission allowances	Operating Expenses - Fuel	1

			Total	$	39
UE	Natural gas (generation)	Operating Expenses - Fuel		$	2
	Heating oil	Operating Expenses - Fuel			25
			Total	$	27
Genco	Natural gas (generation)	Operating Expenses - Fuel		$	(1)
	Heating oil	Operating Expenses - Fuel			17
	SO_2 emission allowances	Operating Expenses - Fuel			1
			Total	$	17
CILCO	Natural gas (resale)	Operating Revenues - Gas		$	6
	Heating oil	Operating Expenses - Fuel			4
			Total	$	10

(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 year ended December 31, 2009:

	Derivatives Subject to Regulatory Deferral		Amount of Gain (Loss) Recognized in Regulatory Liabilities or Assets on Derivatives
Ameren[(a)]	Natural gas	$	41
	Heating oil		5
	Power		(8)
	Uranium		(2)
	Total	$	36
UE	Natural gas	$	3
	Heating oil		5
	Power		(1)
	Uranium		(2)
	Total	$	5
CIPS	Natural gas	$	12
	Power		(85)
	Total	$	(73)
CILCO	Natural gas	$	11
	Power		(38)
	Total	$	(27)
IP	Natural gas	$	15
	Power		(127)
	Total	$	(112)

(a) Includes intercompany eliminations.

UE, CIPS, CILCO and IP 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 electric rate order issued by the MoPSC in January 2009, UE was granted permission to implement a FAC, which was effective March 1, 2009. UE uses derivatives to mitigate its exposure to changing prices of fuel for generation and related transportation costs, and for power price volatility. In connection with the MoPSC's approval of the FAC, gains and losses associated with these types of derivatives are considered refundable to, or recoverable from, customers and thus represent regulatory liabilities or regulatory assets, respectively. During the first quarter of 2009, UE recorded a net regulatory liability of $5 million associated with the reclassification of unrealized gains and losses previously recorded in accumulated OCI and earnings related to open UE derivative positions with delivery dates subsequent to March 1, 2009. The reclassification of previously recorded unrealized gains associated with the derivatives resulted in a $47 million reduction of accumulated OCI. The reclassification of previously recognized unrealized losses resulted in a $42 million increase in pretax earnings, of which $38 million offset fuel expense and $4 million increased operating revenues. See Note 2 - Rate and Regulatory Matters for additional information on the FAC.

As part of the 2007 Illinois Electric Settlement Agreement and the 2009 RFP process, the Ameren Illinois Utilities 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 subject to regulatory deferral by the Ameren Illinois Utilities. Consequently, the Ameren Illinois Utilities 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 the Ameren Illinois Utilities and OCI by Marketing Company. In Ameren's consolidated financial statements, all financial statement effects of the derivative instruments are eliminated. See Note 14 - Related Party Transactions under Part II, Item 8 of the Form 10-K for additional information on these financial contracts.

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 Ameren Illinois Utilities 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 losses totaling less than $1 million in 2009 related to valuation adjustments for counterparty default risk. At December 31, 2009, the counterparty default risk valuation adjustment related to net derivative (assets) liabilities totaled $3 million, $- million, $6 million, $- million, $8 million, and $10 million for Ameren, UE, CIPS, Genco, CILCO and IP, respectively.

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 Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[(a)]	Derivative assets[(b)]	$ 13	$ 3	$ 164	$ 180
	Nuclear Decommissioning Trust Fund[(c)]	232	60	-	292
UE	Derivative assets	1	2	51	54
	Nuclear Decommissioning Trust Fund[(c)]	232	60	-	292
CIPS	Derivative assets[(b)]	-	-	1	1
Genco	Derivative assets[(b)]	-	-	18	18
CILCO	Derivative assets[(b)]	-	-	11	11
IP	Derivative assets[(b)]	-	-	2	2
Liabilities:					
Ameren[(a)]	Derivative liabilities[(b)]	$ 26	$ 2	$ 135	$ 163
UE	Derivative liabilities[(b)]	8	2	28	38
CIPS	Derivative liabilities[(b)]	-	-	156	156
Genco	Derivative liabilities[(b)]	-	-	5	5
CILCO	Derivative liabilities[(b)]	-	-	86	86
IP	Derivative liabilities[(b)]	1	-	248	249

(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.

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, 2008:

		Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[(a)]	Other current assets	$ -	$ -	$ 6	$ 6
	Derivative assets[(b)]	1	19	234	254
	Nuclear Decommissioning Trust Fund[(c)]	164	81	2	247
UE	Derivative assets	-	14	36	50
	Nuclear Decommissioning Trust Fund[(c)]	164	81	2	247
Liabilities:					
Ameren[(a)]	Derivative liabilities[(b)]	$ 9	$ 6	$ 219	$ 234
UE	Derivative liabilities[(b)]	-	3	31	34
CIPS	Derivative liabilities[(b)]	-	-	84	84

Genco	Derivative liabilities[b]	-	-	1	1
CILCO	Derivative liabilities[b]	4	-	55	59
IP	Derivative liabilities[b]	-	-	134	134

(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 ($8) million of receivables, payables, and accrued income, net.

The following table summarizes the changes in the fair value associated with 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	$ 6	$ -	$ -	$ -	$ -	$ -	$ (6)	$ -	$ -
Net derivative contracts	Ameren	$ 15	$ 75	$ 58	$ (85)	$ 48	$ 35	$ (69)	$ 29	$ (2)
	UE	5	-	37	8	45	(6)	(21)	23	2
	CIPS	(84)	-	(10)	(161)	(171)	100	-	(155)	(107)
	Genco	(1)	4	-	-	4	10	-	13	-
	CILCO	(55)	(18)	(5)	(77)	(100)	80	-	(75)	(54)
	IP	(134)	-	(15)	(264)	(279)	167	-	(246)	(172)
Nuclear Decommissioning Trust Fund	Ameren	$ 2	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -
	UE	2	-	-	-	-	(2)	-	-	-

(a) See Note 7 - Derivative Financial Instruments for additional information regarding the recording of net gains and losses on derivatives to the statement of income.

The following table summarizes the changes in the fair value associated with financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 31, 2008:

			Realized and Unrealized Gains (Losses)							
		Beginning Balance at January 1, 2008	Included in Earnings	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, 2008	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at December 31, 2008
Other current assets	Ameren	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 6	$ -
Net derivative contracts	Ameren	$ 19	$ (18)	$ 13	$ (35)	$ (40)	$ 8	$ 28	$ 15	$ (206)
	UE	3	1	13	13	27	(42)	17	5	(6)
	CIPS	38	(1)	-	(127)	(128)	6	-	(84)	(106)
	Genco	1	(2)	-	-	(2)	-	-	(1)	-
	CILCO	21	(34)	-	(43)	(77)	1	-	(55)	(62)
	IP	55	(1)	-	(209)	(210)	21	-	(134)	(174)
Nuclear Decommissioning Trust Fund	Ameren	$ 5	$ -	$ -	$ -	$ -	$ (3)	$ -	$ 2	$ -
	UE	5	-	-	-	-	(3)	-	2	-

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 previous periods. Any reclassifications are reported as transfers in/out of Level 3 at the fair value measurement reported at the beginning of the period in which the changes occur.

See Note 11 - Retirement Benefits for the fair value hierarchy tables detailing Ameren's pension and postretirement plan assets as of December 31, 2009, as well as a table summarizing the changes in Level 3 plan assets during 2009.

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, 2009 and 2008:

	2009		2008	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Ameren:(a)(b)				
Long-term debt and capital lease obligations (including current portion)	**$ 7,317**	**$ 7,719**	$ 6,934	$ 6,144
Preferred stock	**195**	**150**	195	100
UE:				
Long-term debt and capital lease obligations (including current portion)	**$ 4,022**	**$ 4,152**	$ 3,677	$ 3,156
Preferred stock	**113**	**95**	113	62
CIPS:				
Long-term debt (including current portion)	**$ 421**	**$ 436**	$ 421	$ 371
Preferred stock	**50**	**31**	50	22
Genco:				
Long-term debt (including current portion)	**$ 1,023**	**$ 1,046**	$ 774	$ 661
CILCO:				
Long-term debt (including current portion)	**$ 279**	**$ 311**	$ 279	$ 255
Preferred stock	**19**	**15**	19	10
IP:				
Long-term debt (including current portion)	**$ 1,147**	**$ 1,295**	$ 1,400	$ 1,326
Preferred stock	**46**	**35**	46	24

(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 16 - 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, 2009, and 2008.

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. Due to market conditions in 2008, the equity securities weighting was less than targeted levels at December 31, 2008. In January 2009, UE rebalanced its investments to align with its targeted equity securities weighting.

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, 2009, 2008, and 2007:

	2009	**2008**	**2007**
Proceeds from sales	**$ 380**	$ 497	$ 128
Gross realized gains	**5**	5	4
Gross realized losses	**10**	8	3

Net realized and unrealized gains and losses are deferred and recorded as regulatory assets or regulatory liabilities on Ameren's and UE's Consolidated 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, 2009 and 2008:

Security Type	**Cost**	**Gross Unrealized Gain**	**Gross Unrealized Loss**	**Fair Value**
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**
2008:				
Debt securities	$ 109	$ 5	$ 3	$ 111
Equity securities	123	40	29	134
Cash	2	-	-	2
Other(b)	(8)	-	-	(8)
Total	$ 226	$ 45	$ 32	$ 239

(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, 2009:

	Cost	Fair Value
Less than 5 years	$ 50	$ 51
5 years to 10 years	25	26
Due after 10 years	20	20
Total	$ 95	$ 97

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, 2009:

	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	$ 26	$ 1	$ 1	$ (a)	$ 27	$ 1
Equity securities	4	2	27	12	31	14
Total	$ 30	$ 3	$ 28	$ 12	$ 58	$ 15

(a) Amount less than $1 million.

NOTE 10 - PREFERRED STOCK

All classes of UE's, CIPS', CILCO's and IP's preferred stock are entitled to cumulative dividends and have voting rights. The following table presents the outstanding preferred stock of UE, CIPS, CILCO and IP 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, 2009 and 2008:

		Redemption Price (per share)	2009	2008
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
$7.64 Series	330,000 shares	101.27(b)	**33**	33
Total			**$ 113**	$ 113
CIPS:				
With par value of $100 per share, 2 million shares authorized				
4.00% Series	150,000 shares	$ 101.00	**$ 15**	$ 15

4.25% Series	50,000 shares	102.00	**5**	5
4.90% Series	75,000 shares	102.00	**8**	8
4.92% Series	50,000 shares	103.50	**5**	5
5.16% Series	50,000 shares	102.00	**5**	5
6.625% Series	125,000 shares	100.00	**12**	12
Total			**$ 50**	$ 50
CILCO:				
With par value of $100 per share, 1.5 million shares authorized				
4.50% Series	111,264 shares	$ 110.00	**$ 11**	$ 11
4.64% Series	79,940 shares	102.00	**8**	8
Total			**$ 19**	$ 19
IP:				
With par value of $50 per share, 5 million shares authorized				
4.08% Series	225,510 shares	$ 51.50	**$ 12**	$ 12
4.20% Series	143,760 shares	52.00	**7**	7
4.26% Series	104,280 shares	51.50	**5**	5
4.42% Series	102,190 shares	51.50	**5**	5
4.70% Series	145,170 shares	51.50	**7**	7
7.75% Series	191,765 shares	50.00	**10**	10
Total			**$ 46**	$ 46
Less: Shares of IP preferred stock owned by Ameren			**(33)**	(33)
Total Ameren			**$ 195**	$ 195

(a) In the event of voluntary liquidation, $105.50.
(b) Redemption price as of December 31, 2009. Declining to $100 per share in 2012.

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. CIPS has 2.6 million shares of no 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. CILCO has 2 million shares of no par value preference stock authorized, with no such preference stock outstanding. CILCO also has 3.5 million shares of no par value preferred stock authorized, with no shares outstanding. IP has 5 million shares of no par value serial preferred stock authorized and 5 million shares of no par value preference stock authorized, with no such serial preferred stock and preference stock outstanding.

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

The following table presents the benefit liability recorded on the balance sheets of each of the Ameren Companies as of December 31, 2009:

Ameren[(a)]	$ 1,171
UE	403
CIPS	59
Genco	51
CILCO	194
IP	238

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

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, 2009 and 2008. It also provides the amounts included in regulatory assets and accumulated OCI at December 31, 2009 and 2008, that have not been recognized in net periodic benefit costs.

	2009		**2008**	
	Pension Benefits[(a)]	**Postretirement Benefits[(a)]**	**Pension Benefits[(a)]**	**Postretirement Benefits[(a)]**
Accumulated benefit obligation at end of year	**$ 3,041**	**$ (b)**	$ 3,051	$ (b)

Change in benefit obligation:				
Net benefit obligation at beginning of year	**$ 3,303**	**$ 1,182**	$ 3,076	$ 1,253
Service cost	**68**	**19**	60	18
Interest cost	**186**	**66**	186	70
Plan amendments	**-**	**-**	2	-
Participant contributions	**-**	**17**	-	14
Actuarial (gain) loss	**(133)**	**(74)**	145	(105)
Benefits paid	**(169)**	**(72)**	(166)	(73)
Federal subsidy on benefits paid	**(b)**	**5**	(b)	5
Net benefit obligation at end of year	**3,255**	**1,143**	3,303	1,182
Change in plan assets:				
Fair value of plan assets at beginning of year	**2,393**	**593**	2,698	787
Actual return on plan assets	**172**	**140**	(205)	(187)
Employer contributions	**99**	**49**	66	47
Federal subsidy on benefits paid	**-**	**5**	-	5
Participant contributions	**-**	**17**	-	14
Benefits paid	**(169)**	**(72)**	(166)	(73)
Fair value of plan assets at end of year	**2,495**	**732**	2,393	593
Funded status - deficiency	**760**	**411**	910	589
Accrued benefit cost at December 31	**$ 760**	**$ 411**	$ 910	$ 589
Amounts recognized in the balance sheet consist of:				
Current liability	**$ 3**	**$ 3**	$ 2	$ 2
Noncurrent liability	**757**	**408**	908	587
Total	**$ 760**	**$ 411**	$ 910	$ 589
Amounts recognized in regulatory assets consist of:				
Net actuarial loss	**$ 487**	**$ 167**	$ 597	$ 327
Prior service cost (credit)	**33**	**(37)**	40	(40)
Transition obligation	**-**	**9**	-	12
Amounts recognized in accumulated OCI consist of:				
Net actuarial loss	**28**	**25**	57	43
Prior service cost (credit)	**8**	**(13)**	10	(16)
Total	**$ 556**	**$ 151**	$ 704	$ 326

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Not applicable.

The market value of plan assets in 2008 declined by 7% and 26% for the pension and postretirement benefit plans, respectively. In 2008, investment losses in Ameren's pension plan were partially offset by a gain on interest rate swaps, which had a notional value of $700 million at December 31, 2008. The swaps were intended to mitigate the impacts on the funded status of the plan resulting from decreases in the discount rate in the calculation of the pension liability. During 2008, U.S. Treasury yields declined significantly, which resulted in Ameren's pension plan recognizing a $336 million net gain from its interest rate swaps. Ameren closed its interest rate swap position in early 2009. Prior to closing its swap position, U.S. Treasury yields increased, which resulted in Ameren's pension plan recognizing a $74 million net loss in 2009. Ameren's postretirement benefit plans did not have a similar interest rate hedge.

The following table presents the assumptions used to determine our benefit obligations at December 31, 2009 and 2008:

	Pension Benefits		Postretirement Benefits	
	2009	**2008**	**2009**	**2008**
Discount rate at measurement date	**5.75%**	5.75%	**5.75%**	5.75%
Increase in future compensation	**3.50**	4.00	**3.50**	4.00
Medical cost trend rate (initial)	**-**	-	**6.50**	7.00
Medical cost trend rate (ultimate)	**-**	-	**5.00**	5.00
Years to ultimate rate	**-**	-	**3 years**	4 years

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 over 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, 2009, its investment performance in 2009, and its pension funding policy, Ameren expects to make annual contributions of $75 million to $225 million in each of the next five years, with aggregate estimated contributions of $740 million. We expect UE's, CIPS', Genco's, CILCO's, and IP's portion of the future funding requirements to be 66%, 6%, 9%, 9%, and 10%, 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 2009 and 2008:

	Pension Benefits		Postretirement Benefits	
	2009	**2008**	**2009**	**2008**
Ameren[(a)]	**$ 99**	$ 66	**$ 49**	$ 47
UE	**42**	29	**13**	10
CIPS	**6**	4	**1**	1
Genco	**5**	4	**-**	-
CILCO	**12**	6	**7**	7
IP	**10**	9	**20**	21

(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 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. The Ameren Companies will utilize an expected return on plan assets of 8% in 2010. No plan assets are expected to be returned to Ameren during 2010.

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 2010 and our pension and postretirement plans' asset categories as of December 31, 2009 and 2008.

Asset Category	Target Allocation 2010	Percentage of Plan Assets at December 31,	
		2009	**2008**
Pension Plan:			
Cash and cash equivalents	0 - 5%	**1%**	1%
Equity securities:			
U.S. large capitalization	29 - 39	**32**	16

U.S. small and mid capitalization	2 - 12	**10**	10
International and emerging markets	9 - 19	**15**	9
Total equity	50 - 60	**57**	35
Debt securities	35 - 45	**37**	56
Real estate	0 - 9	**4**	6
Private equity	0 - 4	**1**	2
Total		**100%**	100%
Postretirement Plans:			
Cash and cash equivalents	0 - 10%	**4%**	6%
Equity securities:			
U.S. large capitalization	33 - 43	**39**	20
U.S. small and mid capitalization	3 - 13	**10**	21
International	10 - 20	**12**	12
Total equity	55 - 65	**61**	53
Debt securities	30 - 40	**35**	41
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 13 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, 2009. 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.

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	179	30	-	209
Asset-backed securities	-	19	-	19
Other	-	102	1	103

Real estate	-	-	90	90
Private equity	-	-	33	33
Derivative assets	4	-	-	4
Total	$ 810	$ 1,639	$ 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.

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 the year ended December 31, 2009:

	Beginning Balance at January 1, 2009	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, 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, 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	3	66	-	69
Municipal bonds	-	58	-	58
U.S. treasury and agency securities	14	35	-	49
Asset-backed securities	-	23	-	23
Other	-	28	-	28
Derivative assets	1	-	-	1
Total	$ 311	$ 341	$ -	$ 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.

Net Periodic Benefit Cost

The following table presents the components of the net periodic benefit cost of our pension and postretirement benefit plans during 2009, 2008, and 2007:

	Pension Benefits	Postretirement Benefits
	Ameren(a)	Ameren(a)
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
2007:		
Service cost	$ 63	$ 21
Interest cost	180	72
Expected return on plan assets	(206)	(53)
Amortization of:		
Transition obligation	-	2
Prior service cost	11	(8)
Actuarial loss	22	24
Net periodic benefit cost	$ 70	$ 58

(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 2010 are as follows:

	Pension Benefits	Postretirement Benefits
	Ameren(a)	**Ameren(a)**
Regulatory assets:		
Transition obligation	$ -	$ 4
Prior service cost (credit)	5	(4)
Net actuarial loss	33	15
Accumulated OCI:		
Transition obligation	$ -	$ -
Prior service cost (credit)	1	(3)
Net actuarial loss	-	1
Total	$ 39	$ 13

(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. The net actuarial loss subject to amortization is amortized on a straight-line basis over 10 years.

UE, CIPS, Genco, CILCO and IP 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, 2009, 2008 and 2007:

	Pension Costs			Postretirement Costs		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Ameren(a)	**$ 81**	$ 47	$ 70	**$ 34**	$ 33	$ 58
UE	**50**	35	44	**15**	13	26
CIPS	**8**	7	10	**2**	3	6
Genco	**7**	5	7	**3**	2	3
CILCO	**14**	5	8	**7**	6	13
IP	**-**	(2)	4	**12**	14	13

(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, 2009, 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**
2010	$ 194	$ 3	$ 78	$ 3	$ 5
2011	201	3	82	3	5

2012	208	3	86	3	6
2013	214	2	89	3	6
2014	222	2	93	3	6
2015 - 2019	1,225	11	504	16	32

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, 2009, 2008, and 2007:

	Pension Benefits			Postretirement Benefits		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Ameren, UE, CIPS , Genco, CILCO and IP:						
Discount rate at measurement date	**5.75%**	6.15%	5.85%	**5.75%**	6.05%	5.80%
Expected return on plan assets	**8.00**	8.25	8.50	**8.00**	8.25	8.50
Increase in future compensation	**4.00**	4.00	4.00	**4.00**	4.00	4.00
Medical cost trend rate (initial)	**-**	-	-	**7.00**	9.00	9.00
Medical cost trend rate (ultimate)	**-**	-	-	**5.00**	5.00	5.00
Years to ultimate rate	**-**	-	-	**4 years**	4 years	4 years

The table below reflects the sensitivity of Ameren's plans to potential changes in key assumptions:

	Pension		Postretirement	
	Service Cost and Interest Cost	**Projected Benefit Obligation**	**Service Cost and Interest Cost**	**Postretirement Benefit Obligation**
0.25% decrease in discount rate	$ -	$ 93	$ -	$ 31
0.25% increase in salary scale	2	13	-	-
1.00% increase in annual medical trend	-	-	2	32
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, 2009. The plans allowed employees to contribute a portion of their base pay 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 $24 million, $23 million, and $21 million in 2009, 2008, and 2007, respectively.

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, 2009, 2008, and 2007:

	2009	**2008**	**2007**
Ameren(a)	**$ 24**	$ 23	$ 21
UE	**14**	14	14
CIPS	**2**	2	1
Genco	**2**	2	1
CILCO	**4**	2	2
IP	**2**	2	3

(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 as of December 31, 2009, and changes during the year ended December 31, 2009, under the 1998 Plan and the 2006 Plan are presented below:

	Performance Share Units		Restricted Shares	
	Share Units	Weighted-average Fair Value per Unit	Shares	Weighted-average Fair Value per Share
Nonvested at January 1, 2009	675,977	$ 43.28	213,683	$ 47.46
Granted[(a)]	741,738	15.52	-	-
Dividends	-	-	7,934	25.39
Unearned or forfeited[(b)]	(247,065)	57.15	(3,644)	48.30
Earned and vested[(c)]	(225,313)	25.66	(82,277)	45.15
Nonvested at December 31, 2009	945,337	$ 22.07	135,696	$ 48.92

(a) Includes performance share units (share units) granted to certain executive and nonexecutive officers and other eligible employees in March 2009 under the 2006 Plan.
(b) Includes share units granted in 2007 that were not earned based on performance provisions of the award grants.
(c) Includes share units granted in 2007 that vested as of December 31, 2009, 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 $15 million, $22 million, and $18 million for the years ended December 31, 2009, 2008, and 2007, respectively, and a related tax benefit of $6 million, $8 million, and $7 million for the years ended December 31, 2009, 2008, and 2007, respectively. As of December 31, 2009, total compensation cost of $8 million related to nonvested awards not yet recognized is expected to be recognized over a weighted-average period of 16 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 2-year period before being paid to the employee in shares of Ameren common stock. During this 2-year hold period, the employee is paid dividend equivalents on a current basis.

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.

The fair value of each share unit awarded in February 2008 under the 2006 Plan was determined to be $32.35. That amount was based on Ameren’s closing common share price of $44.30 at the grant date and lattice simulations. The significant assumptions used to calculate fair value also included a three-year risk-free rate of 2.264%, dividend yields of 2.3% to 5.4% for the peer group, volatility of 14.43% to 21.51% 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 the company 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.

Stock Options

Options to purchase Ameren common stock were granted under the 1998 Plan at a price not less than the fair-market value of the common shares at the date of grant. Granted options vest over a period of five years, beginning at the date of grant, and they permit accelerated exercising upon the occurrence of certain events, including retirement. There have not been any stock options granted since December 31, 2000. Outstanding options of 58,350 at December 31, 2009, expired in February 2010. There is no expense from stock options for the years ended December 31, 2009, 2008 and 2007, as all options granted were fully vested.

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, 2009, 2008 and 2007:

	Ameren	UE	CIPS	Genco	CILCO	IP
2009:						
Statutory federal income tax rate:	**35%**	**35%**	**35%**	**35%**	**35%**	**35%**
Increases (decreases) from:						
Permanent items[(a)]	**(1)**	**-**	**-**	**(1)**	**(3)**	**-**
Depreciation differences	**(1)**	**(3)**	**(1)**	**-**	**-**	**-**
Amortization of investment tax credit	**(1)**	**(1)**	**(4)**	**-**	**-**	**-**
State tax	**5**	**3**	**5**	**4**	**4**	**5**
Reserve for uncertain tax positions	**(1)**	**-**	**1**	**-**	**(1)**	**-**
Other[(b)]	**(1)**	**(1)**	**-**	**-**	**-**	**-**
Effective income tax rate	**35%**	**33%**	**36%**	**38%**	**35%**	**40%**
2008:						
Statutory federal income tax rate:	35%	35%	35%	35%	35%	35%
Increases (decreases) from:						
Permanent items[(a)]	(1)	1	(1)	(2)	(1)	7
Depreciation differences	-	(1)	(2)	-	(1)	-
Amortization of investment tax credit	(1)	(1)	(10)	-	(1)	-
State tax	4	3	5	5	5	5
Reserve for uncertain tax positions	(1)	(1)	(1)	(1)	-	2
Other[(c)]	(2)	-	(1)	(1)	(1)	1
Effective income tax rate	34%	36%	25%	36%	36%	50%
2007:						
Statutory federal income tax rate:	35%	35%	35%	35%	35%	35%
Increases (decreases) from:						
Permanent items[(a)]	(2)	(2)	2	(1)	(2)	1
Depreciation differences	-	-	3	-	(1)	(3)
Amortization of investment tax credit	(1)	(1)	(6)	(1)	(1)	-
State tax	4	4	6	5	3	5
Reserve for uncertain tax positions	(1)	(1)	-	-	-	-
Other[(d)]	(1)	(2)	(4)	-	-	(1)
Effective income tax rate	34%	33%	36%	38%	34%	37%

(a) Permanent items are treated differently for book and tax purposes and primarily include Internal Revenue Code Section 199 production activity deductions for Ameren, UE, Genco and CILCO, company-owned life insurance for Ameren and CILCO, impacts of Medicare Part D for Ameren, UE, Genco and CILCO, employee stock ownership plan dividends for Ameren, and nondeductible expenses for IP.

(b) Primarily includes low-income housing tax credits and research credits for Ameren and UE.

(c) Primarily includes settlements with state taxing authorities for Ameren, state apportionment changes for Ameren, CIPS, Genco, and CILCO, research credits for Ameren, Genco, and CILCO and low-income housing tax credits for Ameren and CIPS.

(d) Primarily includes low-income housing tax credits for Ameren, UE, CIPS and IP.

The following table presents the components of income tax expense (benefit) for the years ended December 31, 2009, 2008, and 2007:

	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
2009:						
Current taxes:						
Federal	**$ (73)**	**$ (117)**	**$ 13**	**$ 30**	**$ 21**	**$ (7)**
State	**3**	**(31)**	**8**	**11**	**11**	**6**
Deferred taxes:						
Federal	**337**	**239**	**(1)**	**46**	**34**	**45**
State	**74**	**42**	**(2)**	**10**	**7**	**9**
Deferred investment tax credits, amortization	**(9)**	**(5)**	**(2)**	**(1)**	**(1)**	**-**
Total income tax expense	**$ 332**	**$ 128**	**$ 16**	**$ 96**	**$ 72**	**$ 53**
2008:						
Current taxes:						
Federal	$ 165	$ 37	$ 4	$ 81	$ 25	$ (11)
State	10	5	3	15	5	(11)
Deferred taxes:						

Federal	130	86	2	5	9	17
State	31	11	(2)	-	1	10
Deferred investment tax credits, amortization	(9)	(5)	(2)	(1)	(1)	-
Total income tax expense	$ 327	$ 134	$ 5	$ 100	$ 39	$ 5
2007:						
Current taxes:						
Federal	$ 311	$ 105	$ 21	$ 49	$ 36	$ 3
State	17	8	2	9	5	(2)
Deferred taxes:						
Federal	7	22	(10)	17	1	11
State	4	10	(2)	4	(2)	3
Deferred investment tax credits, amortization	(9)	(5)	(2)	(1)	(1)	-
Total income tax expense	$ 330	$ 140	$ 9	$ 78	$ 39	$ 15

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

The following table presents the deferred tax assets and deferred tax liabilities recorded as a result of temporary differences at December 31, 2009 and 2008:

	Ameren(a)	UE	CIPS	Genco	CILCO	IP
2009:						
Accumulated deferred income taxes, net liability (asset):						
Plant related	**$ 2,813**	**$ 1,717**	**$ 197**	**$ 324**	**$ 282**	**$ 261**
Deferred intercompany tax gain/basis step-up	**3**	**(3)**	**79**	**(77)**	**-**	**-**
Regulatory assets (liabilities), net	**52**	**54**	**(1)**	**-**	**(1)**	**1**
Deferred benefit costs	**(313)**	**(98)**	**(3)**	**(25)**	**(56)**	**(18)**
Purchase accounting	**63**	**-**	**-**	**-**	**-**	**(24)**
Leveraged leases	**5**	**-**	**-**	**-**	**-**	**-**
ARO	**(43)**	**(9)**	**-**	**(23)**	**(11)**	**-**
Other	**12**	**11**	**(17)**	**17**	**(10)**	**(5)**
Total net accumulated deferred income tax liabilities(b)	**$ 2,592**	**$ 1,672**	**$ 255**	**$ 216**	**$ 204**	**$ 215**
2008:						
Accumulated deferred income taxes, net liability (asset):						
Plant related	$ 2,377	$ 1,427	$ 182	$ 289	$ 242	$ 205
Deferred intercompany tax gain/basis step-up	4	(3)	90	(87)	-	-
Regulatory assets (liabilities), net	37	44	(3)	-	(3)	-
Deferred benefit costs	(281)	(92)	(5)	(32)	(59)	(1)
Purchase accounting	38	-	-	-	-	(33)
Leveraged leases	6	-	-	-	-	-
ARO	(27)	5	-	(21)	(11)	-
Other	(19)	(12)	(10)	2	(13)	(10)
Total net accumulated deferred income tax liabilities(c)	$ 2,135	$ 1,369	$ 254	$ 151	$ 156	$ 161

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Includes $18 million, $10 million, and $17 million as current assets recorded in the balance sheets for CIPS, CILCO and IP, respectively. Includes $38 million, $12 million and $26 million as current liabilities recorded in the balance sheets for Ameren, UE and Genco respectively.
(c) Includes $3 million, $5 million, $15 million, and $15 million as current assets recorded in the balance sheets for UE, CIPS, CILCO and IP, respectively. Includes $4 million and $15 million as current liabilities recorded in the balance sheets for Ameren and Genco, respectively.

Ameren and IP have Illinois net operating loss carryforwards of $3 million and $1 million, respectively. These will begin to expire in 2017.

Uncertain Tax Positions

On January 1, 2007, the Ameren Companies adopted authoritative accounting guidance, which addressed the determination of whether tax benefits claimed or expected to be claimed on an income tax return should be recorded in the financial statements.

A reconciliation of the change in the unrecognized tax benefit balance during the years ended December 31, 2007, 2008 and 2009, is as follows:

	Ameren	UE	CIPS	Genco	CILCO	IP
Unrecognized tax benefits - January 1, 2007	$ 155	$ 58	$ 15	$ 36	$ 18	$ 12
Increases based on tax positions prior to 2007	31	4	-	10	3	-

Decreases based on tax positions prior to 2007	(21)	(8)	(3)	(8)	-	(2)
Increases based on tax positions related to 2007	17	6	-	6	5	-
Changes related to settlements with taxing authorities	(60)	(28)	(12)	(4)	(7)	(10)
Decreases related to the lapse of statute of limitations	(6)	(6)	-	-	-	-
Unrecognized tax benefits - December 31, 2007	$ 116	$ 26	$ -	$ 40	$ 19	$ -
Increases based on tax positions prior to 2008	16	2	-	4	2	-
Decreases based on tax positions prior to 2008	(46)	(13)	-	(9)	(4)	-
Increases based on tax positions related to 2008	31	6	-	13	8	-
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	$ -	$ 47	$ 25	$ -
Increases based on tax positions prior to 2009	**90**	**76**	**-**	**9**	**5**	**-**
Decreases based on tax positions prior to 2009	**(84)**	**(19)**	**-**	**(31)**	**(18)**	**-**
Increases based on tax positions related to 2009	**19**	**11**	**-**	**3**	**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**	**$ -**	**$ 28**	**$ 15**	**$ -**
Total unrecognized tax benefits that, if recognized, would impact the effective tax rates as of December 31, 2007	$ 26	$ 4	$ -	$ -	$ 1	$ -
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**	**$ -**	**$ -**	**$ 1**	**$ -**

As of January 1, 2007, the Ameren Companies adopted a policy of recognizing 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, 2007, 2008 and 2009, is as follows:

	Ameren	UE	CIPS	Genco	CILCO	IP
Liability for interest - January 1, 2007	$ 12	$ 5	$ 1	$ 4	$ 1	$ -
Interest charges for 2007	5	-	-	3	1	-
Liability for interest - December 31, 2007	$ 17	$ 5	$ 1	$ 7	$ 2	$ -
Interest income for 2008	(7)	(3)	(1)	(3)	-	-
Liability for interest - December 31, 2008	$ 10	$ 2	$ -	$ 4	$ 2	$ -
Interest charges (income) for 2009	**(2)**	**2**	**-**	**(2)**	**(1)**	**-**
Liability for interest - December 31, 2009	**$ 8**	**$ 4**	**$ -**	**$ 2**	**$ 1**	**$ -**

As of January 1, 2007, December 31, 2007, December 31, 2008, and December 31, 2009, the Ameren Companies have accrued no amount for penalties with respect to unrecognized tax benefits.

Ameren’s 2005 and 2006 federal income tax returns are before the Appeals Office of the Internal Revenue Service. The Internal Revenue Service is currently examining Ameren’s 2007 and 2008 income tax returns.

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 financial condition or results of operations.

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 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.

2007 Illinois Electric Settlement Agreement

As part of the 2007 Illinois Electric Settlement Agreement, the Ameren Illinois Utilities, Genco, and AERG agreed to make aggregate contributions of $150 million over four years as part of a comprehensive program to provide $1 billion of funding for rate relief to certain Illinois electric customers, including customers of the Ameren Illinois Utilities.

At December 31, 2009, CIPS, CILCO and IP had receivable balances from Genco for reimbursement of customer rate relief of less than $1 million each. Also at December 31, 2009, CIPS, CILCO and IP had receivable balances from AERG for reimbursement of customer rate relief of less than $1 million each. During the year ended December 31, 2009, Genco incurred charges to earnings of $10 million for customer rate relief contributions and program funding reimbursements to the Ameren Illinois Utilities (CIPS - $3 million, CILCO - $2 million, IP - $5 million), and AERG incurred charges to earnings of $5 million (CIPS - $2 million, CILCO - $1 million, and IP - $2 million). The Ameren Illinois Utilities recorded most of the reimbursements received from Genco and AERG as electric revenue. An immaterial amount was recorded as miscellaneous revenue.

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, 2009, 2008, and 2007:

	December 31,		
	2009	2008	2007
Genco sales to Marketing Company[(a)]	**13,372**	16,551	17,425
AERG sales to Marketing Company[(a)]	**6,817**	6,677	5,316
Marketing Company sales to CIPS[(b)]	**1,283**	2,050	2,396
Marketing Company sales to CILCO[(b)]	**556**	909	1,167
Marketing Company sales to IP[(b)]	**1,690**	2,870	3,493

(a) Both Genco and AERG have a power supply agreement with Marketing Company whereby Genco and AERG sell and Marketing Company purchases all the capacity and energy available from Genco's and AERG's generation fleets.
(b) Marketing Company contracted with CIPS, CILCO, and IP to provide power based on the results of the September 2006 Illinois power procurement auction. The values in this table reflect the physical sales volumes provided in that agreement.

In December 2006, Genco and AERG entered into two separate power supply agreements (PSA) with Marketing Company, whereby Genco and AERG agreed to sell and Marketing Company agreed to purchase all of the capacity available from Genco's and AERG's generation fleets and all of the associated energy. In March 2008, Genco and AERG entered into an amendment to their respective PSAs with Marketing Company. Under the amendment, Genco and AERG are liable to Marketing Company in the event of an unplanned outage or derate (reduction in rated capacity) due to sudden, unanticipated failure or accident within the generating plant site of one or more of its generating units. Genco's and AERG's liability in such cases will be for the positive difference, if any, between the market price of capacity or energy Genco and AERG do not deliver and the contract price under the PSA for that capacity or energy. An unplanned outage or derate that continues for one year or more is an event of default under the PSA. In the event of Marketing Company's unexcused failure to receive energy under the PSA, Marketing Company would be required to pay Genco and AERG the positive difference, if any, between the contract price and the price that Genco and AERG, acting in a commercially reasonable manner, actually receives when it resells the unreceived energy, less any reasonable related transmission, ancillary service, or brokerage costs. In January 2010, Genco and AERG entered into an amendment to their respective PSAs with Marketing Company primarily because of the EEI ownership transfer to Genco.

Both of the PSAs will 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.

In accordance with a January 2006 ICC order, an auction was held in September 2006 to procure power for CIPS, CILCO and IP beginning January 1, 2007. Through the auction, Marketing Company contracted with CIPS, CILCO and IP to provide power for residential and small commercial customers (less than one megawatt of demand) as follows:

	Term Ending		
	May 31, 2008	May 31, 2009	May 31, 2010

Term	17 Months	29 Months	41 Months
Megawatts[(a)]	300	750	750
Cost per megawatthour	$ 64.77	$ 64.75	$ 66.05

(a) Before impact to Ameren Illinois Utilities' load due to customer switching.

Capacity Supply Agreements

To replace the power supply contracts that expired on May 31, 2008, the Ameren Illinois Utilities 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 the Ameren Illinois Utilities' capacity RFPs. Marketing Company contracted to supply a portion of the Ameren Illinois Utilities' capacity for $6 million. In addition, UE contracted to supply a portion of the Ameren Illinois Utilities' capacity for $1 million.

CIPS, CILCO and IP, as electric load serving entities, must acquire capacity sufficient to meet their obligations to customers. In 2009, the Ameren Illinois Utilities used an RFP process, administered by the IPA, to contract the necessary capacity for the period from June 1, 2009, through May 31, 2012. Both Marketing Company and UE were winning suppliers in the Ameren Illinois Utilities' capacity RFP process. In April 2009, Marketing Company contracted to supply capacity to the Ameren Illinois Utilities for $4 million, $9 million, and $8 million for the twelve months ending May 31, 2010, 2011, and 2012, respectively. In April 2009, UE contracted to supply capacity to the Ameren Illinois Utilities for $2 million, $2 million, and $1 million for the twelve months ending May 31, 2010, 2011, and 2012, respectively.

Energy Swaps

As part of the 2007 Illinois Electric Settlement Agreement, the Ameren Illinois Utilities 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 Ameren Illinois Utilities. Consequently, the Ameren Illinois Utilities 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 the Ameren Illinois Utilities 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, 2009:

Period	Volume	Price per Megawatthour
January 1, 2010 - May 31, 2010	800 MW	$ 51.09
June 1, 2010 - December 31, 2010	1,000 MW	51.09
January 1, 2011 - December 31, 2011	1,000 MW	52.06
January 1, 2012 - December 31, 2012	1,000 MW	53.08

To replace the supply contracts that expired on May 31, 2008, the Ameren Illinois Utilities 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 the Ameren Illinois Utilities' 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.

CIPS, CILCO and IP, as electric load serving entities, must acquire energy sufficient to meet their obligations to customers. In 2009, the Ameren Illinois Utilities used an 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 Ameren Illinois Utilities' energy swap RFP process. In May 2009, Marketing Company entered into financial instruments that fixed the price that the Ameren Illinois Utilities will pay for approximately 80,000 megawatthours at approximately $48 per megawatthour during the twelve months ending May 31, 2010 and for approximately 89,000 megawatthours at approximately $48 per megawatthour during the twelve months ending May 31, 2011.

Electric Resource Sharing Agreement

On June 1, 2008, FERC accepted an electric resource sharing agreement among the Ameren Illinois Utilities for various joint costs of the

Ameren Illinois Utilities, including capacity, renewable energy credits, and rate swaps. The purpose of the agreement is to allocate these costs among the Ameren Illinois Utilities in an equitable manner, based on their respective retail loads.

Interconnection and Transmission Agreements

UE, CIPS and IP are parties to an interconnection agreement for the use of their respective transmission lines and other facilities for the distribution of power. In addition, CILCO and IP, and CILCO and CIPS, are parties to similar interconnection agreements. These agreements have no contractual expiration date, but may be terminated by any party with three years' notice.

Generator Interconnection Agreement

In 2008, Genco and CIPS signed an agreement requiring Genco to fund the construction costs of upgrades to CIPS' 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 CIPS for the costs of the transmission upgrades. When the transmission assets were placed in service, CIPS paid Genco, with interest, for the costs of the transmission upgrades. In 2009, CIPS 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 CIPS signed an agreement requiring Marketing Company to fund the cost of certain upgrades to CIPS' electric transmission system. Under the agreement, Marketing Company paid CIPS $5 million 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

In 2006, IP and AITC entered into a joint ownership agreement to construct, own, operate, and maintain certain electric transmission systems in Illinois. Under the terms of this agreement, IP and AITC are responsible for their applicable share of all costs related to the construction, operation, and maintenance of electric transmission systems. This agreement will terminate when either IP or AITC is the sole owner of the transmission systems or when the transmission systems are decommissioned.

Support Services Agreements

Ameren Services and AFS provide support services to their affiliates. Ameren Energy, Inc. provided support services until December 31, 2007. 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.

CILCO Support Services

On January 1, 2009, approximately 570 Ameren Services employees who provided support services to the Ameren Illinois Utilities were transferred to CILCO (Illinois Regulated). As CILCO employees, they provide services to CIPS and IP as well as to CILCO. The cost of support services provided by CILCO to CIPS and IP, including wages, employee benefits, professional services, and other expenses, are based on, or are an allocation of, actual costs incurred.

Executory Tolling, Gas Sales, and Transportation Agreements

Prior to 2009, under an executory tolling agreement, CILCO purchased steam, chilled water, and electricity from Medina Valley. In January 2009, CILCO transferred the tolling agreement to Marketing Company. In connection with the tolling agreement, Medina Valley purchases gas to fuel its generating facility from AFS under a fuel supply and services agreement.

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 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 CIPS and Genco, respectively, were $4 million, $7 million, and $10 million for the years ended December 31, 2009, 2008, and 2007, respectively. Genco's subordinated note payable to CIPS associated with the transfer in 2000 of CIPS' electric generating assets and related liabilities to Genco matures on May 1, 2010.

CILCO (AERG) had outstanding borrowings from Ameren of $288 million at December 31, 2009, and had no outstanding borrowings directly from Ameren at December 31, 2008. The average interest rate on these borrowings was 6.1% for the year ended December 31, 2009. CILCO (AERG) recorded interest charges of $13 million for Ameren borrowings for the year ended December 31, 2009.

UE had no outstanding borrowings directly from Ameren at December 31, 2009, and had outstanding borrowings directly from Ameren of $92 million at December 31, 2008. The average interest rate on these borrowings was 1.2% for the year ended December 31, 2009 (2008 - 3.6%). UE recorded interest charges of less than $1 million, $1 million, and $4 million for Ameren borrowings for the years ended December 31, 2009, 2008, and 2007, respectively.

Collateral Postings

Under the terms of the power supply agreements between Marketing Company and the Ameren Illinois Utilities, which were entered into as part of the September 2006 Illinois power procurement auction, collateral must be posted by Marketing Company under certain market conditions to protect the Ameren Illinois Utilities in the event of nonperformance by Marketing Company. The collateral postings are unilateral, which means that Marketing Company as the supplier is the only counterparty required to post collateral. At December 31, 2009 and 2008, there were no collateral postings necessary by Marketing Company related to the 2006 auction power supply agreements.

Under the terms of the 2008 Illinois power procurement RFPs, collateral had to be posted by Marketing Company and the Ameren Illinois Utilities under certain market conditions. The collateral postings were bilateral, which means that either counterparty could be required to post collateral. As of December 31, 2008, the Ameren Illinois Utilities had cash collateral postings as follows with Marketing Company: CIPS - $7 million, CILCO - $4 million, and IP - $11 million. These bilateral collateral postings were eliminated in consolidation on Ameren's financial statements.

Under the terms of the 2009 Illinois power procurement agreements entered into through an RFP process administered by the IPA, suppliers must post collateral under certain market conditions to protect the Ameren Illinois Utilities in the event of nonperformance. The collateral postings are unilateral, which means only the suppliers are 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, 2009, there were no collateral postings necessary between UE and the Ameren Illinois Utilities or between Marketing Company and the Ameren Illinois Utilities related to the 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 and $11 million for the years ended December 31, 2008 and 2007, respectively.

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.

The following table presents the impact on UE, CIPS, Genco, CILCO, and IP of related party transactions for the years ended December 31, 2009, 2008 and 2007. 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	CIPS	Genco	CILCO	IP
Genco and AERG power supply agreements with Marketing Company	Operating Revenues	**2009**	**$ (a)**	**$ (a)**	**$ 850**	**$ 430**	**$ (a)**
		2008	(a)	(a)	893	344	(a)
		2007	(a)	(a)	831	279	(a)
UE ancillary services and capacity agreements with CIPS, CILCO and IP	Operating Revenues	**2009**	**3**	**(a)**	**(a)**	**(a)**	**(a)**
		2008	13	(a)	(a)	(a)	(a)
		2007	18	(a)	(a)	(a)	(a)
UE and Genco gas transportation agreement	Operating Revenues	**2009**	**1**	**(a)**	**(a)**	**(a)**	**(a)**
		2008	1	(a)	(a)	(a)	(a)
		2007	1	(a)	(a)	(a)	(a)
Genco gas sales to Medina Valley	Operating Revenues	**2009**	**(a)**	**(a)**	**1**	**(a)**	**(a)**
Genco gas sales to distribution companies	Operating Revenues	**2009**	**(a)**	**(a)**	**2**	**(a)**	**(a)**
		2008	(a)	(a)	7	(a)	(a)
CILCO support services(b)	Operating Revenues	**2009**	**(a)**	**(a)**	**(a)**	**70**	**(a)**
Total Operating Revenues		**2009**	**$ 4**	**$ (a)**	**$ 853**	**$ 500**	**$ (a)**
		2008	14	(a)	900	344	(a)
		2007	19	(a)	831	279	(a)
UE and Genco gas transportation agreement	Fuel	**2009**	**$ (a)**	**$ (a)**	**$ 1**	**$ (a)**	**$ (a)**
		2008	(a)	(a)	1	(a)	(a)
		2007	(a)	(a)	1	(a)	(a)
CIPS, CILCO and IP agreements with Marketing Company	Purchased Power	**2009**	**$ (a)**	**$ 140**	**$ (a)**	**$ 65**	**$ 195**
		2008	(a)	145	(a)	65	204
		2007	(a)	157	(a)	76	227
CIPS, CILCO and IP ancillary services and capacity agreements with UE	Purchased Power	**2009**	**(a)**	**1**	**(a)**	**(c)**	**1**
		2008	(a)	4	(a)	2	7
		2007	(a)	6	(a)	3	9
Ancillary services agreement with Marketing Company	Purchased Power	**2009**	**(a)**	**(c)**	**(a)**	**(c)**	**(c)**
		2008	(a)	6	(a)	3	8
		2007	(a)	3	(a)	1	4
Executory tolling agreement with Medina Valley	Purchased Power	**2009**	**(a)**	**(a)**	**(a)**	**(d)**	**(a)**
		2008	(a)	(a)	(a)	39	(a)
		2007	(a)	(a)	(a)	38	(a)
Total Purchased Power		**2009**	**$ (a)**	**$ 141**	**$ (a)**	**$ 65**	**$ 196**
		2008	(a)	155	(a)	109	219
		2007	(a)	166	(a)	118	240

Insurance recoveries	Operating Revenues and Purchased Power	**2009**	**$ -**	**$ (a)**	**$ -**	**$ -**	**$ (a)**
		2008	(c)	(a)	(11)	(4)	(a)
		2007	(12)	(a)	(2)	(7)	(a)
Gas purchases from Genco	Gas Purchased for Resale	**2009**	**$ (a)**	**$ (a)**	**$ (a)**	**$ 2**	**$ (c)**
		2008	(a)	(c)	(a)	6	(a)
Ameren Services support services agreement	Other Operations and Maintenance	**2009**	**$ 126**	**$ 29**	**$ 27**	**$ 33**	**$ 48**
		2008	130	50	28	51	76
		2007	137	47	24	49	73
CILCO support services	Other Operations and Maintenance	**2009**	**(a)**	**21**	**(a)**	**(a)**	**32**
Ameren Energy, Inc. support services agreement(e)	Other Operations and Maintenance	2007	8	(a)	(c)	(a)	(a)
AFS support services agreement	Other Operations and Maintenance	**2009**	**7**	**2**	**3**	**2**	**3**
		2008	7	2	3	2	2
		2007	6	2	2	2	2
Insurance premiums(f)	Other Operations and Maintenance	**2009**	**2**	**(a)**	**1**	**1**	**(a)**
		2008	8	(a)	4	3	(a)
		2007	19	(a)	4	2	(a)

Agreement	Income Statement Line Item		UE	CIPS	Genco	CILCO	IP
Total Other Operations and Maintenance Expenses		**2009**	**$ 135**	**$ 52**	**$ 31**	**$ 36**	**$ 83**
		2008	145	52	35	56	78
		2007	170	49	30	53	75
Money pool borrowings (advances)	Interest (Charges) Income	**2009**	**$ (c)**	**$ (c)**	**$ (1)**	**$ (1)**	**$ (c)**
		2008	(c)	(c)	(c)	(c)	(c)
		2007	(c)	(c)	8	(c)	1

(a) Not applicable.
(b) Includes revenues relating to Property and Plant additions during 2009 (CIPS - $6 million and IP - $11 million).
(c) Amount less than $1 million.
(d) In January 2009, CILCO transferred the tolling agreement to Marketing Company.
(e) Ameren Energy, Inc. was eliminated December 31, 2007, through an internal reorganization.
(f) 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 14 - Related Party Transactions and Note 16 - Callaway Nuclear Plant in this report.

Callaway Nuclear Plant

The following table presents insurance coverage at UE’s Callaway nuclear plant at December 31, 2009. The property coverage and the nuclear liability coverage must be renewed on October 1 and January 1, respectively, of each year.

Type and Source of Coverage	Maximum Coverages	Maximum Assessments for Single Incidents

Public liability and nuclear worker liability:				
American Nuclear Insurers	$	300[(a)]	$	-
Pool participation		12,219[(b)]		118[(c)]
	$	12,519[(d)]	$	118
Property damage:				
Nuclear Electric Insurance Ltd.	$	2,750[(e)]	$	23
Replacement power:				
Nuclear Electric Insurance Ltd	$	490[(f)]	$	9
Energy Risk Assurance Company	$	64[(g)]	$	-

(a) Effective January 1, 2010, limit was increased to $375 million.
(b) Provided through mandatory participation in an industry-wide retrospective premium assessment program.
(c) Retrospective premium under Price-Anderson. This is subject to retrospective assessment with respect to a covered loss in excess of $300 million in the event of an incident at any licensed U.S. commercial reactor, payable at $17.5 million per year.
(d) Limit of liability for each incident under the Price-Anderson 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 in a calendar 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.
(e) 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.
(f) 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.
(g) 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 Price-Anderson.

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 industry-wide 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.

Leases

The following table presents our lease obligations at December 31, 2009:

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	After 5 Years
Ameren:[(a)]					
Capital lease payments[(b)]	$ 685	$ 32	$ 65	$ 65	$ 523
Less amount representing interest	367	28	55	55	229
Present value of minimum capital lease payments	318	4	10	10	294
Operating leases[(c)]	351	37	59	52	203
Total lease obligations	$ 669	$ 41	$ 69	$ 62	$ 497
UE:					
Capital lease payments[(b)]	$ 685	$ 32	$ 65	$ 65	$ 523
Less amount representing interest	367	28	55	55	229
Present value of minimum capital lease payments	318	4	10	10	294
Operating leases[(c)]	157	14	25	25	93
Total lease obligations	$ 475	$ 18	$ 35	$ 35	$ 387
CIPS:					
Operating leases[(c)]	$ 2	$ -	$ 1	$ 1	$ -

Genco:					
Operating leases(c)	$ 133	$ 9	$ 17	$ 17	$ 90
CILCO:					
Operating leases(c)	$ 16	$ 1	$ 2	$ 2	$ 11
IP:					
Operating leases(c)	$ 6	$ 2	$ 3	$ 1	$ -

(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 Less than 1 Year, 1-3 Years, and 3-5 Years 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, 2009, 2008 and 2007:

	2009	2008	2007
Ameren(a)	**$ 27**	$ 19	$ 15
UE	**19**	20	19
CIPS	**6**	9	9
Genco	**5**	2	2
CILCO	**6**	7	7
IP	**9**	13	12

(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 the purchase of electric capacity and natural gas for distribution. The table below presents our estimated fuel, electric capacity, and other commitments at December 31, 2009. Ameren's and UE's electric capacity obligations include a 15-year, 102-MW power purchase agreement with a wind farm operator. 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, 2009. Ameren's tax credit obligation is a $51 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, 2009, as Ameren has a legally enforceable right to offset under authoritative accounting guidance.

In September 2009, UE announced an agreement with a landfill owner to install CTs at a landfill site in St. Louis County, Missouri, which would generate approximately 15 MW of electricity by burning methane gas collected from the landfill. Construction of the CTs is expected to begin in 2010, and the CTs are expected to begin generating power in 2011. UE signed a 20-year supply agreement with the landfill owner to purchase methane gas. The obligation information presented below includes total estimated methane gas purchase commitments. Related design and construction commitments associated with this project are included in the Other column in the table below.

	Coal	Natural Gas	Nuclear	Electric Capacity	Methane Gas	Other	Total
Ameren:(a)							
2010	$ 987	$ 580	$ 55	$ 22	$ -	$ 70	$ 1,714
2011	874	461	16	22	1	85	1,459
2012	639	317	43	22	3	75	1,099
2013	218	205	55	22	3	58	561
2014	120	121	100	22	4	68	435
Thereafter	675	214	329	207	101	254	1,780
Total	$ 3,513	$ 1,898	$ 598	$ 317	$ 112	$ 610	$ 7,048
UE:							
2010	$ 527	$ 83	$ 55	$ 22	$ -	$ 42	$ 729
2011	447	63	16	22	1	54	603
2012	265	50	43	22	3	43	426
2013	142	39	55	22	3	42	303
2014	106	27	100	22	4	52	311
Thereafter	597	52	329	207	101	154	1,440
Total	$ 2,084	$ 314	$ 598	$ 317	$ 112	$ 387	$ 3,812
CIPS:							

2010	$ -	$ 91	$ -	$ (b)	$ -	$ 2	$ 93
2011	-	74	-	(b)	-	2	76
2012	-	64	-	(b)	-	2	66
2013	-	48	-	-	-	2	50
2014	-	37	-	-	-	2	39
Thereafter	-	10	-	-	-	12	22
Total	$ -	$ 324	$ -	$ (b)	$ -	$ 22	$ 346
Genco:							
2010	$ 223	$ 10	$ -	$ -	$ -	$ -	$ 233
2011	192	10	-	-	-	-	202
2012	167	5	-	-	-	-	172
2013	32	3	-	-	-	-	35
2014	-	3	-	-	-	-	3
Thereafter	-	3	-	-	-	-	3
Total	$ 614	$ 34	$ -	$ -	$ -	$ -	$ 648
CILCO:							
2010	$ 93	$ 169	$ -	$ (b)	$ -	$ 1	$ 263
2011	103	136	-	(b)	-	3	242
2012	87	96	-	(b)	-	3	186
2013	36	68	-	-	-	3	107
2014	14	37	-	-	-	3	54
Thereafter	78	94	-	-	-	19	191
Total	$ 411	$ 600	$ -	$ (b)	$ -	$ 32	$ 1,043
IP:							
2010	$ -	$ 220	$ -	$ (b)	$ -	$ 6	$ 226
2011	-	176	-	(b)	-	10	186
2012	-	100	-	(b)	-	11	111
2013	-	48	-	-	-	11	59
2014	-	17	-	-	-	11	28
Thereafter	-	54	-	-	-	69	123
Total	$ -	$ 615	$ -	$ (b)	$ -	$ 118	$ 733

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) See Ameren Illinois Utilities' Power Purchase Agreements below for additional information regarding electric capacity commitments.

Ameren Illinois Utilities' Power Purchase Agreements

Beginning on January 1, 2007, CIPS, CILCO and IP were required to obtain all electric supply requirements for customers who do not purchase electric supply from third-party suppliers. The power procurement costs incurred by CIPS, CILCO and IP are passed directly to their customers. CIPS, CILCO and IP entered into power supply contracts with the winning bidders, including their affiliate, Marketing Company, in the Illinois reverse power procurement auction held in September 2006. Under these contracts, the electric suppliers are responsible for providing to CIPS, CILCO and IP energy, capacity, certain transmission, volumetric risk management, and other services necessary for the Ameren Illinois Utilities to serve the electric load needs of residential and small commercial customers (with less than one megawatt of demand) at an all-inclusive fixed price. These contracts commenced on January 1, 2007 with one-third of the supply contracts expiring in each of May 2008, 2009 and 2010.

Existing supply contracts from the September 2006 auction remain in place. Through the Illinois procurement auction held in September 2006, CIPS, CILCO and IP contracted for their anticipated fixed-price loads for residential and small commercial customers (less than one megawatt of demand) as follows:

Term	41 Months Ending May 31, 2010
CIPS' load in megawatts[a]	639
CILCO's load in megawatts[a]	328
IP's load in megawatts[a]	928
Total load in megawatts[a]	1,895
Cost per megawatthour	$ 66.05

(a) Represents peak forecast load for CIPS, CILCO and IP. Actual load could be different if customers elect not to purchase power pursuant to the power procurement auction but instead to receive power from a different supplier. Load could also be affected by weather, among other things.

In January 2009, the ICC approved the electric power procurement plan filed by the IPA for both the Ameren Illinois Utilities and Commonwealth Edison Company. As a result, in the second quarter of 2009, the IPA procured electric capacity, financial energy swaps, and renewable energy credits through an RFP process on behalf of the Ameren Illinois Utilities. Electric capacity was procured in April 2009 for the period June 1, 2009, through May 31, 2012. The Ameren Illinois Utilities contracted to purchase between 800 and 3,500 MW of capacity per month at an average price of approximately $41 per MW-day over the three-year period. Financial energy swaps were procured in May 2009 for the period June 1, 2009, through May 31, 2011. The Ameren Illinois Utilities contracted to purchase approximately ten million megawatthours of financial energy swaps at an average price of approximately $36 per megawatthour. Renewable energy credits were procured in May 2009 for the period June 1, 2009, through May 31, 2010. The Ameren Illinois Utilities contracted to purchase 720,000 renewable energy credits at an average price of approximately $16 per credit. For additional information regarding electric capacity and financial energy swaps entered into with UE and Marketing Company, see Note 14 - Related Party Transactions. The following table presents the Ameren Illinois Utilities' commitments for these contracts at December 31, 2009:

	2010	2011	2012
Electric capacity	$ 26	$ 26	$ 1
Financial energy swaps	183	56	-
Renewable energy credits	6	-	-

2007 Illinois Electric Settlement Agreement

The 2007 Illinois Electric Settlement Agreement provided $1 billion of funding over a four-year period beginning in 2007 for rate relief for certain electric customers in Illinois. Funding for the settlement is provided by electric generators in Illinois and certain Illinois electric utilities. The Ameren Illinois Utilities, Genco, and AERG agreed to fund an aggregate of $150 million, of which the following contributions remain to be made at December 31, 2009:

	Ameren	CIPS	CILCO (Illinois Regulated)	IP	Genco	CILCO (AERG)
2010[(a)]	$ 3.0	$ 0.3	$ 0.2	$ 0.5	$ 1.4	$ 0.6

(a) Estimated.

Also as part of the 2007 Illinois Electric Settlement Agreement, the Ameren Illinois Utilities 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. 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 laws and regulations. These laws and regulations address noise, emissions, impacts to air, land and water, protected and cultural resources (such as wetlands, endangered species, 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. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or our operations. The more significant matters are discussed below.

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 May 2005, the EPA issued regulations with respect to SO_2 and NO_x emissions (the Clean Air Interstate Rule) and mercury emissions (the Clean Air Mercury Rule). The federal Clean Air Interstate Rule requires generating facilities in 28 eastern states, which include 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 is scheduled to take effect in 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 units from the list of sources subject to the MACT requirements under the Clean Air Act. In February 2009, the U.S. Supreme Court denied a petition for review filed by a group representing the electric utility industry. The impact of this decision is that the EPA will move forward with 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 regulation by March 2011 and finalize the regulation by November 2011. Compliance is expected to be required in 2015. We cannot predict at this time the estimated capital or operating costs for compliance with such future environmental rules.

In July 2008, the U.S. Court of Appeals for the District of Columbia issued a decision that vacated the federal Clean Air Interstate Rule. The court ruled that the regulation contained several fatal flaws, including a regional cap-and-trade program that cannot be used to facilitate the attainment of ambient air quality standards for ozone and fine particulate matter. In September 2008, the EPA, as well as several environmental groups, a group representing the electric utility industry, and the National Mining Association, all filed petitions for rehearing with the U.S. Court of Appeals. In December 2008, the U.S. Court of Appeals essentially reversed its July 2008 decision to vacate the federal Clean Air Interstate Rule. The U.S. Court of Appeals granted the EPA petition for reconsideration and remanded the rule to the EPA for further action to remedy the rule's flaws in accordance with the U.S. Court of Appeals' July 2008 opinion in the case. The impact of the decision is that the existing Illinois and Missouri rules to implement the federal Clean Air Interstate Rule will remain in effect until the federal Clean Air Interstate Rule is revised by the EPA, at which point the Illinois and Missouri rules may be subject to change. The EPA has stated that it expects to issue a new proposed version of the Clean Air Interstate Rule in 2010 and a final version in 2011.

The state of Missouri has adopted rules to implement the federal Clean Air Interstate Rule for regulating SO_2 and NO_x emissions from electric generating units. The rules are a significant part of Missouri's plan to attain existing ambient standards for ozone and fine particulates, as well as meeting the federal Clean Air Visibility Rule. The rules are expected to reduce NO_x emissions by 30% and SO_2 emissions by 75% by 2015. As a result of the Missouri rules, UE will use allowances and install pollution control equipment. UE's costs to comply with SO_2 emission reductions required by the Clean Air Interstate Rule could increase materially if the EPA determines that existing allowances granted to sources under the Acid Rain Program cannot be used for compliance with the Clean Air Interstate Rule or if a new allowance program is mandated by revisions to the Clean Air Interstate Rule. 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, CILCO (AERG) and EEI have begun putting into service equipment designed to reduce mercury emissions. Genco, CILCO (AERG) and EEI will also need to install additional pollution control equipment. Current plans include installing scrubbers for SO_2 reduction as well as optimizing operations of selective catalytic reduction (SCR) systems for NO_x reduction at certain coal-fired plants in Illinois. The Illinois Joint Committee on Administrative Rules approved a rule amendment in June 2009 that revised certain requirements of the MPS. As a result, Genco and CILCO (AERG) collectively were able to defer to subsequent years an estimated $300 million of environmental capital expenditures originally scheduled for 2009 through 2011.

In March 2008, the EPA finalized regulations that will lower the ambient standard for ozone. Illinois and Missouri have each submitted their recommendations to the EPA for designating nonattainment areas. A final action by the EPA to designate nonattainment areas is expected in March 2010. State implementation plans will need to be submitted in 2013 unless Illinois and Missouri seek extensions for various requirement dates. Additional emission reductions may be required as a result of future state implementation plans. In January 2010, the EPA announced its plans to revise the ozone standard to a level lower than the level set in 2008. At this time, we are unable to determine the impact state implementation plans for such regulations would have on our results of operations, financial position, and liquidity.

The table below presents estimated capital costs that are based on current technology to comply with state air quality implementation plans, the MPS, federal ambient air quality standards including ozone and fine particulates, and the federal Clean Air Visibility rule. The estimates shown in the table below could change depending upon additional federal or state requirements, the requirements under a MACT standard, new technology, variations in costs of material or labor, or alternative compliance strategies, among other factors. The timing of estimated capital costs may also be influenced by whether emission allowances are used to comply with any future rules, thereby deferring capital investment. During 2009, Ameren identified significant opportunities to defer or reduce planned capital spending, which are reflected in the estimates provided in the table. The capital cost estimates are lower than previously anticipated, in part because of Ameren's ability to manage its generating fleet to minimize emissions while complying with emission limits and air permit requirements. Furthermore, previous estimates included assumptions about potential and developing air regulations, including rules that were subsequently vacated by the courts. These estimates include capital spending to comply primarily with existing and known regulations as of December 31, 2009.

	2010	2011 - 2014	2015 - 2017	Total
UE[(a)]	$ 160	$ 170 - $ 215	$ 25 - $ 35	$ 355- $ 410
Genco	95	650 - 785	30 - 35	775 - 915
CILCO(AERG)	5	120 - 150	65 - 75	190 - 230
EEI	5	275 - 335	0 - 5	280 - 345
Ameren	$ 265	$1,215 - $1,485	$120- $ 150	$1,600-$ 1,900

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

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 Clean Air Interstate Rule. All existing generating facilities have been allocated allowances based on past production and the statutory emission reduction goals. NO_X allowances allocated under the NO_X Budget Trading Program can be used for the seasonal NO_X program under the federal Clean Air Interstate Rule. 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 are expected to comply with the NO_X limits through the use and purchase of allowances or 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, 2009.

UE, Genco, CILCO (AERG) and EEI expect to use a substantial portion of their SO_2 and NO_X allowances for ongoing operations. Environmental regulations, including the Clean Air Interstate Rule, 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 Clean Air Interstate Rule requires a reduction in SO_2 emissions by increasing the ratio of Acid Rain Program allowances surrendered. The current Acid Rain Program requires the surrender of one SO_2 allowance for every ton of SO_2 emitted. Unless revised by the EPA as a result of the U.S. Court of Appeals' remand, the Clean Air Interstate Rule program will require that SO_2 allowances of vintages 2010 through 2014 be surrendered at a ratio of two allowances for every ton of emission. SO_2 allowances with vintages of 2015 and beyond will be required to be surrendered at a ratio of 2.86 allowances for every ton of emission. In order to accommodate this change in surrender ratio and to comply with the federal and state regulations, UE, Genco, CILCO (AERG), and EEI expect to install control technology designed to further reduce SO_2 emissions, as discussed above.

The Clean Air Interstate Rule has both an ozone season program and an annual program for regulating NO_X emissions, with separate allowances issued for each program. The Clean Air Interstate Rule ozone season program replaced the NO_X Budget Trading Program beginning in 2009. Allocations for UE's Missouri generating facilities for the years 2009 through 2014 were 11,665 tons per ozone season and 26,842 tons annually. Allocations for Genco's generating facility in Missouri were one ton for the ozone season and three tons annually. Allocations for UE's, Genco's, CILCO's (AERG), and EEI's Illinois generating facilities for the years 2010 and 2011 were 90, 3,442, 1,368, and 1,758 tons per ozone season, respectively, and 93, 8,302, 3,419, and 4,565 tons annually, respectively.

Global Climate Change

In June 2009, the U.S. House of Representatives passed energy legislation entitled "The American Clean Energy and Security Act of 2009" that, if enacted, would establish an economy-wide cap-and-trade program. The overarching goal of this proposed cap-and-trade program is to reduce greenhouse gas emissions from capped sources, including coal-fired electric generation units, to 3% below 2005 levels by 2012, 17% below 2005 levels by 2020, 42% below 2005 levels by 2030, and 83% below 2005 levels by the year 2050. The proposed legislation provides an allocation of free emission allowances and greenhouse gas offsets to utilities, as well as certain merchant coal-fired electric generators in competitive markets. This aspect of the proposed legislation would mitigate some of the cost of compliance for the Ameren Companies. However, the amount of free allowances decline over time and are ultimately phased out. The proposed legislation also contains, among other things, a federal renewable energy standard of 6% by 2012 that increases gradually to 20% by 2020, of which up to 25% of the goal can be met by energy efficiency. The proposed legislation also establishes performance standards for new coal plants, requires electric utilities to develop plans to support plug-in hybrid vehicles, and requires load-serving entities to reduce peak electric demand through energy efficiency and Smart Grid technologies. In September 2009, climate change legislation entitled “The Clean Energy Jobs and American Power Act” was introduced in the U.S. Senate that was similar to that passed by the U.S. House of Representatives in June 2009, although it proposes a slightly greater reduction in greenhouse gas emissions in the year 2020 and grants fewer emission allowances to the electricity sector. Under both proposed pieces of legislation, large sources of CO_2 emissions will be required to obtain and retire an allowance for each ton of CO_2 emitted. The allowances may be allocated to the sources without cost, sold to the sources through auctions or other mechanisms, or traded among parties. “The Clean Energy Jobs and American Power Act” was voted out of committee in November 2009. In December 2009, Senators Kerry, Graham and Lieberman introduced a framework for Senate legislation in 2010. The framework lacks specifics, but it is consistent with the House-passed legislation except that it emphasizes the need for greater support for nuclear power and energy independence through support for clean energy and drilling for oil and natural gas. Senate leadership has stated that consideration of climate legislation will be postponed until spring 2010. In addition, the reduction of greenhouse gas emissions has been identified as a high priority by President Obama’s administration. Although we cannot predict the date of enactment or the requirements of any future climate change legislation or regulations, we believe it is possible that some form of federal legislation or regulations to control emissions of greenhouse gases will become law during the current 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 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, a principal greenhouse gas. Ameren’s analysis shows that if either “The American Clean Energy and Security Act of 2009” or “The Clean Energy Jobs and American Power Act” were enacted into law in its current form, 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 about half the amount of CO_2 that coal emits when burned to produce electricity. As a result, economy-wide shifts favoring natural gas as a fuel source for electricity generation also could affect the cost of heating for our utility customers and many industrial processes. Ameren believes that wholesale natural gas costs could rise significantly as well. Higher costs for energy could contribute to reduced demand for electricity and natural gas.

In early December of 2009, representatives from countries around the globe met in Copenhagen, Denmark, to attempt to develop an international treaty to supersede the Kyoto Protocol, which set mandatory greenhouse gas reduction requirements for participating countries. The parties were unable to reach agreement regarding mandatory greenhouse gas emissions reductions. However, certain countries, including the United States, entered into an agreement called the “Copenhagen Accord.” The Copenhagen Accord provides a mechanism for countries to make economy-wide greenhouse gas emission mitigation commitments for reducing emissions of greenhouse gases by 2020 and provides for developed countries to fund greenhouse gas emissions mitigation projects in developing countries. Any commitment under the Copenhagen Accord is subject to congressional action on climate change.

Additional requirements to control greenhouse gas emissions and address global climate change may also arise pursuant to the Midwest Greenhouse Gas Reduction Accord, an agreement signed by the governors of Illinois, Iowa, Kansas, Michigan, Wisconsin and Minnesota to develop a strategy to achieve energy security and to reduce greenhouse gas emissions through a cap-and-trade mechanism. The advisory group to the Midwest governors provided draft final recommendations on the design of a greenhouse gas reduction program in June 2009. In October 2009, the Midwestern Governors Association held a forum to review some of the advisory group’s recommendations. The October 2009 forum did not yield any significant updates to the Midwest Greenhouse Gas Reduction Accord’s work toward a cap-and-trade mechanism. The recommendations have not been endorsed or approved by the individual state governors. It is uncertain whether legislation to implement the recommendations will be implemented or passed by any of the states, including Illinois.

With regard to the control of greenhouse gas emissions under federal regulation, in 2007, the U.S. Supreme Court issued a decision finding that the EPA has the authority to regulate CO_2 and other greenhouse gases from automobiles as “air pollutants” under the Clean Air Act. This decision required the EPA to determine whether greenhouse gas emissions may reasonably be anticipated to endanger public health or welfare, or, in the alternative, to provide a reasonable explanation as to why greenhouse gas emissions should not be regulated. In December 2009, in response to the decision of the U.S. Supreme Court, 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. It is expected that the EPA will issue a rule by the end of March 2010 to control greenhouse gas emissions from light-duty vehicles such as automobiles. Once this rule is effective, greenhouse gases will, for the first time, be a regulated air pollutant under the Clean Air Act. The EPA has taken the position that the regulation of greenhouse gas emissions from new motor vehicles under the Clean Air Act will trigger the applicability of other Clean Air Act provisions, such as the Title V Operating Permit Program and the NSR provisions, which apply to greenhouse gas emissions from stationary sources. This would include fossil-fuel-fired electricity generating plants.

Recognizing the difficulties presented by regulating at once virtually all emitters of greenhouse gases, the EPA announced in September 2009 a proposed rule, known as the "tailoring rule," that would establish new higher thresholds for regulating greenhouse gas emissions from stationary sources, such as power plants. The rule would require any source that emits at least 25,000 tons per year of greenhouse gases measured as CO_2 equivalents (CO_2e) to have an operating permit under Title V Operating Permit Program of the Clean Air Act. Sources that already have an operating permit would have greenhouse gas-specific provisions added to their permits upon renewal. Currently, all Ameren power plants have operating permits that, depending on the final rule, may be modified when they are renewed to address greenhouse gas emissions. The proposed tailoring rule also provides that if physical changes or changes in operation at major sources result in an increase in emissions of greenhouse gases over a threshold ranging from 10,000 tons to 25,000 tons of CO_2e, the emitters would be required to obtain a permit under the NSR/Prevention of Significant Deterioration program and to install the best available technology 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. The EPA has committed to provide guidance about the best available control technology for new and modified major sources of greenhouse gas emissions. The tailoring rule is expected to be finalized in March 2010, but any federal climate change legislation that is enacted may preempt the proposed rule, particularly as it relates to power plant greenhouse gas emissions. This proposed rule has no immediate impact on Ameren's, UE's, Genco's or CILCO's (AERG) generating facilities. The extent to which this proposed rule could have a material impact on our generating facilities depends upon future EPA guidelines as to what constitutes the best available control technology for greenhouse gas emissions from power plants, whether physical changes or change in operation subject to the rule would occur at our power plants, and whether federal legislation that preempts the proposed rule is passed.

The EPA also finalized regulations in September 2009 that would require certain categories of businesses, including fossil-fuel-fired power plants, to monitor and report their annual greenhouse gas emissions, beginning in January 2011 for 2010 emissions. CO_2 emissions from fossil-fuel-fired power plants subject to the Clean Air Act's acid rain program have been monitored and reported for over fifteen years. Thus, this new rule covering greenhouse gas emissions is not expected to have a material effect on our operations. It will require additional reporting of greenhouse gas emissions from various gas operations and possibly other minor sources within our system.

Recent federal appellate court decisions have ruled that common law causes of action, such as nuisance, can be used to redress damages resulting from global climate change. In *State of Connecticut v. American Electric Power* ("AEP"), the U.S. Court of Appeals for the Second Circuit ruled in September 2009 that public nuisance claims brought by states, New York City and public land trusts could proceed and were not beyond the scope of judicial relief. Ameren's generating plants were not named in the AEP litigation. In *Comer v. Murphy Oil* ("Comer"), a Mississippi property owner sued several industrial companies, alleging that CO_2 emissions created the atmospheric conditions, that resulted in Hurricane Katrina. The U.S. Court of Appeals for the Fifth Circuit issued a ruling in Comer in October 2009 that permits this cause of action to proceed. Comer is seeking class action certification on behalf of similarly situated property owners. Additional legal challenges and appeals are expected in both the Comer and AEP cases. The rulings in these cases may spur other claimants to file suit against greenhouse gas emitters, including Ameren. The courts did not rule on the merits of the lawsuits, only that plaintiffs had standing to pursue their claims. Under some of the versions of greenhouse gas legislation currently pending in Congress, nuisance claims could be rendered moot. We are unable to predict the outcome of lawsuits seeking damages that litigants claim are attributable to climate change and their impact on our results of operations, financial position, and liquidity.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would 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 we request recovery of these costs through rates, our 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 UE, Genco, CILCO (through AERG) and EEI 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, Genco's, AERG's and EEI's results of operations, financial position, and liquidity.

The impact on us of future initiatives related to greenhouse gas emissions and global climate change is unknown. Although compliance costs are unlikely in the near future, federal legislative, federal regulatory and state-sponsored initiatives to control greenhouse gases continue to progress, making it more likely that some form of greenhouse gas emissions control will eventually be required. Since these initiatives continue to evolve, the impact on our coal-fired generation plants and our customers' costs is unknown, but any impact would likely be negative. Our costs of complying with any mandated federal or state greenhouse gas program could have a material impact on our future results of operations, financial position, and liquidity.

NSR and Notice of Violation

The EPA is engaged in an enforcement initiative targeted at coal-fired power plants in the United States to determine whether those power plants failed to comply with the requirements of the NSR and New Source Performance Standards (NSPS) provisions under the Clean Air Act when the plants implemented modifications. The EPA's inquiries focus on whether projects performed at power plants should have triggered various permitting requirements and the installation of pollution control equipment.

In April 2005, Genco received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act. It sought detailed operating and maintenance history data with respect to Genco's Coffeen, Hutsonville, Meredosia and Newton facilities, EEI's Joppa facility, and AERG's E.D. Edwards and Duck Creek facilities. In 2006, the EPA issued a second Section 114(a) request to Genco regarding projects at the Newton facility. All of these facilities are coal-fired power plants. In September 2008, the EPA issued a third Section 114(a) request regarding projects at all of Ameren's Illinois coal-fired power plants. In May 2009, we completed our response to the most recent information request, but we are unable to predict the outcome of this matter.

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 maintenance, repair and replacement projects at UE's Labadie, Meramec, Rush Island, and Sioux coal-fired power plant facilities, dating back to the mid-1990s, triggered NSR requirements. The EPA alleges that UE violated the Title V operating permit program by failing to include such NSR requirements in its operating permits or applications for those permits. If litigation regarding this matter occurs, it could take many years to resolve the underlying issues alleged in the Notice of Violation. UE believes its defenses to the allegations described in the Notice of Violation are meritorious and will defend itself vigorously; however, there can be no assurances that it will be successful in its efforts.

Resolution of these matters could have a material adverse impact on the future results of operations, financial position, and liquidity of Ameren, UE, Genco, AERG and EEI. A resolution could result in increased capital expenditures for the installation of control technology, increased operations and maintenance expenses, and fines or penalties.

Clean Water Act

In July 2004, the EPA issued rules under the Clean Water Act that require cooling-water intake structures to have the best technology available for minimizing adverse environmental impacts on aquatic species. These rules pertain to all existing generating facilities that currently employ a cooling-water intake structure whose flow exceeds 50 million gallons per day. The rules may require facilities to install additional technology on their cooling water intakes or take other protective measures and to do extensive site-specific study and monitoring. There is also the possibility that the rules may lead to the installation of cooling towers on some of our generating facilities. On April 1, 2009, the U.S. Supreme Court ruled that the EPA can compare the costs of technology for protecting aquatic species to the benefits of that technology in order to establish the "best technology available" standards applicable to the cooling water intake structure at existing power plants under the Clean Water Act. The EPA is expected to propose revised rules in 2010. Until the EPA reissues the rules and such rules are adopted, and until the studies on the aquatic impacts of the power plants are completed, we are unable to estimate the costs of complying with these rules. Such costs are not expected to be incurred prior to 2012. All major generation facilities at UE, Genco, AERG and EEI with cooling water systems could be subject to these new regulations.

Remediation

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

As of December 31, 2009, CIPS, CILCO and IP owned or were otherwise responsible for several former MGP sites in Illinois. CIPS has 15, CILCO has 4, and IP has 25 sites. All of these sites are in various stages of investigation, evaluation, and remediation. Ameren currently anticipates completion of remediation at these sites by 2015, except for a CIPS site that is expected to be completed by 2017. The ICC permits each company to recover remediation and litigation costs associated with its former MGP sites from its Illinois electric and natural gas utility customers through environmental adjustment rate riders. To be recoverable, such costs must be prudently and properly incurred. Costs are subject to annual review by the ICC. As of December 31, 2009, estimated obligations were: CIPS - $47 million to $62 million, CILCO - less than $1 million, and IP - $112 million to $175 million. CIPS, CILCO and IP have liabilities of $47 million, less than $1 million, and $112 million, respectively, recorded to represent estimated minimum obligations, as no other amount within the range was a better estimate. In 2009, after the completion of site investigations and the selection of remediated actions, CIPS and IP increased their remediation liabilities.

CIPS is also responsible for the cleanup of a former coal ash landfill in Coffeen, Illinois. As of December 31, 2009, CIPS estimated that obligation at $0.5 million to $6 million. CIPS recorded a liability of $0.5 million to represent its estimated minimum obligation for this site, as no other amount within the range was a better estimate. IP is also responsible for the cleanup of a landfill, underground storage tanks, and a water treatment plant in Illinois. As of December 31, 2009, IP recorded a liability of $0.8 million to represent its best estimate of the obligation for these sites.

In addition, UE owns or is otherwise responsible for 10 MGP sites in Missouri and one site in Iowa. UE does not currently have in effect in Missouri a rate rider mechanism that permits recovery of remediation costs associated with MGP sites from utility customers. UE does not have any retail utility operations in Iowa that would provide a source of recovery of these remediation costs. As of December 31, 2009, UE estimated its obligation at $3 million to $5 million. UE has a liability of $3 million recorded to represent its estimated minimum obligation for its MGP sites, as no other amount within the range was a better estimate.

UE also is responsible for four waste sites in Missouri that have corporate cleanup liability as a result of federal agency mandates. UE concluded cleanups at two of these sites, and no further remediation actions are anticipated at those two sites. One of the remaining waste sites for which UE has corporate cleanup responsibility is a former coal tar distillery located in St. Louis, Missouri. In July 2008, the EPA issued an administrative order to UE pertaining to this distillery operated by Koppers Company or its predecessor and successor companies. UE is the current owner of the site, but UE did not conduct any of the manufacturing operations involving coal tar or its byproducts. UE along with two other PRPs have reached an agreement with the EPA about the scope of the site investigation. The investigation will occur later this year. As of December 31, 2009, UE estimated this obligation at $2 million to $5 million. UE has a liability of $2 million recorded to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In June 2000, the EPA notified UE and numerous other companies, including Solutia, that former landfills and lagoons in Sauget, Illinois, may contain soil and groundwater contamination. These sites are known as Sauget Area 2. From about 1926 until 1976, UE operated a power generating facility adjacent to Sauget Area 2. UE currently owns a parcel of property that was once used as a landfill. Under the terms of an Administrative Order and Consent, UE has joined with other PRPs to evaluate the extent of potential contamination with respect to Sauget Area 2.

The Sauget Area 2 investigations overseen by the EPA have been completed. The results have been submitted to the EPA and a record of decision is expected in 2010. Once the EPA has selected a remedy, it will begin negotiations with various PRPs to implement it. Over the last several years, numerous other parties have joined the PRP group and all presumably will participate in the funding of any required remediation. In addition, Pharmacia Corporation and Monsanto Company have agreed to assume the liabilities related to Solutia's former chemical waste landfill in the Sauget Area 2, notwithstanding Solutia's filing for bankruptcy protection. As of December 31, 2009, UE estimated its obligation at $0.4 million to $10 million. UE has a liability of $0.4 million recorded to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In December 2004, AERG submitted a plan to the Illinois EPA to address groundwater and surface water issues associated with the recycle pond, ash ponds, and reservoir at the Duck Creek power plant facility. Information submitted by AERG is currently under review by the Illinois EPA. CILCO (AERG) has a liability of $3 million at December 31, 2009, for the estimated cost of the remediation effort, which involves discharging recycle-system water into the Duck Creek reservoir and the eventual closure of ash ponds in order to address these groundwater and surface water issues.

Our operations or those of our predecessor companies involve the use, disposal of, and in appropriate circumstances, the cleanup of substances regulated under environmental protection laws. We are unable to determine whether such practices will result in future environmental commitments or impact our results of operations, financial position, or liquidity.

Ash Management

There has been increased activity at both state and federal levels to examine the need for additional regulation of ash pond facilities and coal combustion byproducts (CCB) and wastes. The EPA is considering regulating CCB under the hazardous waste regulations, which could impact future disposal and handling costs at our power plant facilities. We believe it is likely that the EPA will continue to allow some beneficial use, such as recycling, of CCB without classifying them as hazardous wastes. As part of its proposed regulations, the EPA is considering requirements that coal-fired power plants engage in the mandatory closure of active surface impoundments used for the management of CCB. In September 2009, the EPA announced that it expects to revise federal rules governing wastewater discharges from coal-fired power plants. Some form of additional regulation concerning ash ponds, and the handling and disposal of CCB and waste, is expected to be proposed in early 2010. Depending upon the scope and timing of these rules, Ameren may be required to alter the management of CCB waste, including beneficial reuse, and to discontinue or phase out the use of the ash ponds. Ameren's CCB impoundments were not identified in the EPA's 2009 list of 44 high-hazard potential impoundments containing CCB.

In addition, the Illinois EPA has requested that UE, Genco, CILCO (AERG) and EEI establish groundwater monitoring plans for their active and inactive ash impoundments in Illinois. Genco is currently petitioning the Illinois Pollution Control Board to issue a site specific rule approving the closure of an ash pond at its Hutsonville power plant. Ameren has entered into discussions with the Illinois EPA about a framework for closure of additional ash ponds in Illinois, including the ash ponds at Venice and Duck Creek, when such facilities are ultimately taken out of service. The permits for the Venice and Duck Creek ash ponds both expire in 2010. UE, Genco and CILCO (AERG) have recorded AROs, based on current laws, for the estimated costs of the retirement of their ash ponds.

At this time, we are unable to predict the effects any such state and federal regulations might have on our results of operations, financial position, and liquidity.

Pumped-storage Hydroelectric Facility Breach

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 has property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance does not cover lost electric margins and penalties paid to FERC. UE expects that the total cost for cleanup, damage and liabilities, excluding costs to rebuild the upper reservoir, will be approximately $205 million. As of December 31, 2009, UE had paid $205 million, including costs resulting from the FERC-approved stipulation and consent agreement. As of December 31, 2009, UE had recorded expenses of $35 million, primarily in prior years, for items not covered by insurance and had recorded a $170 million receivable for amounts recoverable from insurance companies under liability coverage. As of December 31, 2009, UE had received $100 million from insurance companies, which reduced the insurance receivable balance subject to liability coverage to $70 million.

UE received approval from FERC to rebuild the upper reservoir at its Taum Sauk plant and is in the process of testing the rebuilt facility. UE expects the Taum Sauk plant to become operational in the second quarter of 2010. The estimated cost to rebuild the upper reservoir is in the range of $490 million. As of December 31, 2009, UE had recorded a $420 million receivable due from insurance companies under property insurance coverage related to the rebuilding of the facility and the reimbursement of replacement power costs. As of December 31, 2009, UE had received $362 million from insurance companies, which reduced the property insurance receivable balance as of December 31, 2009, to $58 million.

Under UE's insurance policies, all claims by or against UE are subject to review by its insurance carriers. In July 2009, three insurance carriers filed a petition against Ameren in the Circuit Court of St. Louis County, Missouri, seeking a declaratory judgment that the property insurance policy does not require these three insurers to indemnify Ameren for their share of the entire cost of construction associated with the facility rebuild design being utilized. The three insurers allege that they, along with the other policy participants, presented a rebuild design that was consistent with their insurance coverage obligations and that the insurance policies do not require these insurers to pay their share of the costs of construction associated with the design being used. These insurers have estimated a cost of approximately $214 million for their rebuild design compared to the estimated $490 million cost of the design approved by FERC and implemented by Ameren. Ameren has filed an answer and counterclaim in the Circuit Court of St. Louis County, Missouri, against these insurers. The counterclaim asserts that the three insurance carriers have breached their obligations under the property insurance policies issued to Ameren and UE. Ameren seeks payment of a sum to-be-determined for all amounts covered by these policies incurred in the facility rebuild, including power replacement costs, interest, and attorneys' fees. The insurers that are parties to the litigation represent approximately 40%, on a weighted average basis, of the property insurance policy coverage between the disputed amounts of $214 million and $490 million.

On August 31, 2009, Ameren and the property insurance carriers that are not parties to the above litigation (the "Settling Insurance Companies") reached a settlement of any and all claims, liabilities, and obligations arising out of, or relating to, coverage under its property insurance policy, including those related to the rebuilding of the facility and the reimbursement of replacement power costs. All payments from the Settling Insurance Companies were received by UE in September 2009.

Until Ameren's remaining 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. Ameren and UE expect to recover, through insurance, 80% to 90% of the total property insurance claim for the Taum Sauk incident. Beyond insurance, 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 rate payers 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, 2009, UE had capitalized in property and plant qualifying Taum Sauk-related costs of $99 million that UE believes qualify for potential recovery in electric rates under the terms of the November 2007 State of Missouri Settlement. The inclusion of such costs in UE's electric rates is subject to review and approval by the MoPSC in a future rate case. Any amounts not recovered through insurance, in electric rates, or otherwise, could result in charges to earnings, which could be material.

Asbestos-related Litigation

Ameren, UE, CIPS, Genco, CILCO and IP have been named, along with numerous other parties, in a number of lawsuits filed by plaintiffs claiming varying degrees of injury from asbestos exposure. Most have been filed in the Circuit Court of Madison County, Illinois. The total number of defendants named in each case is significant; as many as 192 parties are named in some pending cases and as few as six in others. However, in the cases that were pending as of December 31, 2009, the average number of parties was 71.

The claims filed against Ameren, UE, CIPS, Genco, CILCO and IP allege injury from asbestos exposure during the plaintiffs' activities at our present or former electric generating plants. Former CIPS plants are now owned by Genco, and former CILCO plants are now owned by AERG. Most of IP's plants were transferred to a former parent subsidiary prior to Ameren's acquisition of IP. As a part of the transfer of ownership of the CIPS and CILCO generating plants, CIPS and CILCO have contractually agreed to indemnify Genco and AERG, respectively, for liabilities associated with asbestos-related claims arising from activities prior to the transfer. Each lawsuit seeks unspecified damages that, if awarded at trial, typically would be shared among the various defendants.

The following table presents the pending asbestos-related lawsuits filed against the Ameren Companies as of December 31, 2009:

Specifically Named as Defendant						
Ameren	UE	CIPS	Genco	CILCO	IP	Total(a)
1	26	32	-	15	40	75

(a) Total does not equal the sum of the subsidiary unit lawsuits because some of the lawsuits name multiple Ameren entities as defendants.

As of December 31, 2009, nine asbestos-related lawsuits were pending against EEI. The general liability insurance maintained by EEI provides coverage with respect to liabilities arising from asbestos-related claims.

At December 31, 2009, Ameren, UE, CIPS, CILCO and IP had liabilities of $14 million, $4 million, $3 million, $2 million and $5 million, respectively, recorded to represent their best estimate of their obligations related to asbestos claims.

IP 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 by IP from a trust fund established by IP. At December 31, 2009, the trust fund balance was approximately $23 million, including accumulated interest. If cash expenditures are less than the amount in base rates, IP 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.

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

NOTE 16 - CALLAWAY NUCLEAR PLANT

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or $^1/_{10}$ of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel. Pursuant to this act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates and sells from its Callaway nuclear plant. Electric utility rates charged to customers provide for recovery of such costs. The DOE's last announced date of when it expects a permanent storage facility for spent fuel to be available was 2020, and the DOE continues to evaluate permanent storage alternatives. UE has sufficient installed storage capacity at its Callaway nuclear plant until 2020. It has the capability for additional storage capacity through the licensed life of the plant. The delayed availability of the DOE's disposal facility is not expected to adversely affect the continued operation of the Callaway nuclear plant through its currently licensed life.

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 2009, 2008, and 2007. 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 minor tritium contamination discovered on the Callaway nuclear plant site, which did not result in a significant increase in the decommissioning cost estimate. Costs 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 17 - GOODWILL

We evaluate goodwill for impairment as of October 31 of each year, or more frequently if events and circumstances indicate that the asset might be impaired. Goodwill impairment testing is a two-step process. The first step involves a comparison of the estimated fair value of a reporting unit with its carrying amount. If the estimated fair value of the reporting unit exceeds the carrying value, goodwill of the reporting unit is considered unimpaired. If the carrying amount of the reporting unit exceeds its estimated fair value, a second step is performed to measure the amount of impairment, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit's goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined by allocating the estimated fair value of the reporting unit to the estimated fair value of its existing assets and liabilities in a manner similar to a purchase price allocation. The unallocated portion of the estimated fair value of the reporting unit is the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss equivalent to the difference is recorded as a reduction of goodwill and a charge to operating expense.

During the first quarter of 2009, we concluded that events had occurred and circumstances had changed which required us to perform an interim goodwill impairment test. The following events triggered this impairment test:

- A significant decline in Ameren's market capitalization.

- The continuing decline in market prices for electricity.
- A decrease in observable industry market multiples.

The fair value of Ameren's and IP's reporting units was estimated based on a risk-adjusted, probability-weighted discounted cash flow model that considered multiple operating scenarios. Key assumptions in the determination of fair value included the use of an appropriate discount rate, estimated five-year cash flows, and an exit value based on observable industry market multiples. We use our best estimates in making these evaluations. We consider various factors, including forward price curves for energy and fuel costs, the regulatory environment, and operating costs. For the interim test conducted as of March 31, 2009, the discount rate used was 3.8%, based on the 20-year treasury yield. To assess the reasonableness of the estimated reporting unit fair values, the sum of the estimated fair values of the Ameren reporting units is reconciled to our current market capitalization plus an estimated control premium. Ameren's reporting units and IP's reporting unit did not require a second step assessment; the results of the step one tests indicated no impairment of goodwill as of March 31, 2009.

The annual impairment test, conducted as of October 31, 2009, did not result in a second step assessment; the test indicated no impairment of Ameren's or IP's goodwill. The annual test was conducted in a manner similar to the interim test described above. Ameren's market capitalization was less than the book value of its equity as of the October 31, 2009, testing date and during the remainder of 2009. However, the sum of the estimated fair values of Ameren reporting units exceeded the combined Ameren reporting unit carrying value as of October 31, 2009. We believe the difference between Ameren's market capitalization and the sum of the estimated fair values of the Ameren reporting units as of October 31, 2009, can be explained by the application of a reasonable control premium to our share price. The discount rate used was 4.2%, based on the 20-year treasury yield. At Ameren's Illinois Regulated reporting unit and IP's Illinois Regulated reporting unit, either (1) a decrease in the forecasted cash flows of ten percent, (2) an increase in the discount rate of one percentage point, or (3) a decrease of the market multiple by one would not have resulted in the carrying value of the reporting unit exceeding their fair values. However, the estimated fair value of Ameren's Merchant Generation reporting unit exceeded its carrying value by a nominal amount as of October 31, 2009. The estimated fair value of Ameren's Merchant Generation reporting unit exceeded its carrying value by approximately $95 million, or 3%. The failure in the future of any reporting unit to achieve forecasted operating results and cash flows or a decline of observable industry market multiples may further reduce its estimated fair value below its carrying value, which would likely result in the recognition of a goodwill impairment charge.

Ameren and IP will continue to monitor the actual and forecasted operating results, cash flows, market capitalization, market prices for electricity, and observable industry market multiples of their reporting units for signs of possible declines in estimated fair value and potential goodwill impairment.

Ameren has identified three reporting units, which also represent Ameren's reportable segments. The Ameren reporting units are Missouri Regulated, Illinois Regulated, and Merchant Generation. IP has one reporting unit, Illinois Regulated. Ameren's reporting units have been defined and goodwill has been evaluated at the operating segment level in accordance with authoritative accounting guidance. The following tables provide a reconciliation of the beginning and ending carrying amounts of goodwill by reporting unit, for Ameren and IP, for the years 2009 and 2008:

Ameren

	2009				2008			
	Missouri Regulated	Illinois Regulated	Merchant Generation	Total(a)	Missouri Regulated	Illinois Regulated	Merchant Generation	Total(a)
Gross goodwill at January 1	$ -	$ 411	$ 420	$ 831	$ -	$ 411	$ 420	$ 831
Accumulated impairment losses	-	-	-	-	-	-	-	-
Goodwill, net of accumulated impairment losses	$ -	$ 411	$ 420	$ 831	$ -	$ 411	$ 420	$ 831
Changes during the year	-	-	-	-	-	-	-	-
Goodwill, net of impairment losses at December 31	$ -	$ 411	$ 420	$ 831	$ -	$ 411	$ 420	$ 831

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

IP

	2009				2008			
	Missouri Regulated	Illinois Regulated	Merchant Generation	Total	Missouri Regulated	Illinois Regulated	Merchant Generation	Total
Gross goodwill at January 1	$ -	$ 214	$ -	$ 214	$ -	$ 214	$ -	$ 214

Accumulated impairment losses		-		-		-		-		-		-		-		-
Goodwill, net of accumulated impairment losses	$	-	$	214	$	-	$	214	$	-	$	214	$	-	$	214
Changes during the year		-		-		-		-		-		-		-		-
Goodwill, net of impairment losses at December 31	$	-	$	214	$	-	$	214	$	-	$	214	$	-	$	214

NOTE 18 - SEGMENT INFORMATION

Ameren has three reportable segments: Missouri Regulated, Illinois Regulated, and Merchant Generation. The Missouri Regulated segment for Ameren includes all the operations of UE's business as described in Note 1 - Summary of Significant Accounting Policies, except for UE's 40% interest in EEI (which in February 2008 was transferred to Resources Company through an internal reorganization). The Illinois Regulated segment for Ameren consists of the regulated electric and gas transmission and distribution businesses of CIPS, CILCO, and IP, as described in Note 1 - Summary of Significant Accounting Policies, and AITC. The Merchant Generation segment for Ameren consists primarily of the operations or activities of Genco, the CILCORP parent company, AERG, EEI, Medina Valley and Marketing Company. The category called Other primarily includes Ameren parent company activities.

UE has one reportable segment: Missouri Regulated. The Missouri Regulated segment for UE includes all the operations of UE's business as described in Note 1 - Summary of Significant Accounting Policies, except for UE's former 40% interest in EEI.

CILCO has two reportable segments: Illinois Regulated and Merchant Generation. The Illinois Regulated segment for CILCO consists of the regulated electric and gas transmission and distribution businesses of CILCO. The Merchant Generation segment for CILCO consists of the generation business of AERG. Other comprises minor activities not reported in the Illinois Regulated or Merchant Generation segments.

The following tables present information about the reported revenues and specified items included in net income of Ameren, UE, and CILCO for the years ended December 31, 2009, 2008 and 2007, and total assets as of December 31, 2009, 2008 and 2007.

Ameren

	Missouri Regulated	Illinois Regulated	Merchant Generation	Other	Intersegment Eliminations	Consolidated
2009						
External revenues	**$ 2,847**	**$ 2,912**	**$ 1,322**	**$ 9**	**$ -**	**$ 7,090**
Intersegment revenues	**27**	**27**	**390**	**19**	**(463)**	**-**
Depreciation and amortization	**357**	**216**	**126**	**26**	**-**	**725**
Interest and dividend income	**29**	**5**	**-**	**33**	**(37)**	**30**
Interest charges	**229**	**153**	**119**	**48**	**(41)**	**508**
Income taxes (benefit)	**128**	**77**	**151**	**(24)**	**-**	**332**
Net income (loss) attributable to Ameren Corporation[(a)]	**259**	**124**	**247**	**(18)**	**-**	**612**
Capital expenditures	**872**	**415**	**408**	**9**	**-**	**1,704**
Total assets	**12,301**	**7,344**	**4,921**	**1,657**	**(2,433)**	**23,790**
2008						
External revenues	$ 2,922	$ 3,433	$ 1,482	$ 2	$ -	$ 7,839
Intersegment revenues	38	45	455	18	(556)	-
Depreciation and amortization	329	219	109	28	-	685
Interest and dividend income	33	15	3	30	(38)	43
Interest charges	193	144	99	44	(40)	440
Income taxes (benefit)	134	16	217	(40)	-	327
Net income (loss) attributable to Ameren Corporation[(a)]	234	32	352	(13)	-	605
Capital expenditures	874	359	611	52	-	1,896
Total assets	11,529	7,088	4,568	1,227	(1,741)	22,671
2007						
External revenues	$ 2,915	$ 3,318	$ 1,315	$ 14	$ -	$ 7,562
Intersegment revenues	46	62	497	40	(645)	-
Depreciation and amortization	333	217	105	26	-	681
Interest and dividend income	34	26	2	52	(59)	55
Interest charges	194	132	107	29	(39)	423
Income taxes (benefit)	143	25	182	(20)	-	330
Net income attributable to Ameren Corporation[(a)]	281	47	281	9	-	618
Capital expenditures	625	321	395	40	-	1,381

Total assets	10,852	6,409	3,784	965	(1,258)	20,752

(a) Represents net income (loss) available to common stockholders; 100% of CILCO's preferred stock dividends are included in the Illinois Regulated segment.

UE

	Missouri Regulated	Other(a)	Consolidated UE
2009			
Revenues	**$ 2,874**	**$ -**	**$ 2,874**
Depreciation and amortization	**357**	**-**	**357**
Interest charges	**229**	**-**	**229**
Income taxes	**128**	**-**	**128**
Net income(b)	**259**	**-**	**259**
Capital expenditures	**872**	**-**	**872**
Total assets	**12,301**	**-**	**12,301**
2008			
Revenues	$ 2,960	$ -	$ 2,960
Depreciation and amortization	329	-	329
Interest charges	193	-	193
Income taxes	134	-	134
Net income(b)	234	11	245
Capital expenditures	874	-	874
Total assets	11,529	-	11,529
2007			
Revenues	$ 2,961	$ -	$ 2,961
Depreciation and amortization	333	-	333
Interest charges	194	-	194

	Missouri Regulated	Other(a)	Consolidated UE
Income taxes (benefit)	143	(3)	140
Net income(b)	281	55	336
Capital expenditures	625	-	625
Total assets	10,852	51	10,903

(a) Included 40% interest in EEI through February 29, 2008.
(b) Represents net income available to the common stockholder (Ameren).

CILCO

	Illinois Regulated	Merchant Generation	Other	Intersegment Eliminations	Consolidated CILCO
2009					
External revenues	**$ 655**	**$ 427**	**$ -**	**$ -**	**$ 1,082**
Intersegment revenues	**1**	**-**	**-**	**(1)**	**-**
Depreciation and amortization	**32**	**38**	**-**	**-**	**70**
Interest charges	**25**	**16**	**-**	**-**	**41**
Income taxes	**8**	**64**	**-**	**-**	**72**
Net income(a)	**20**	**114**	**-**	**-**	**134**
Capital expenditures	**63**	**91**	**-**	**-**	**154**
Total assets	**1,264**	**1,119**		**(1)**	**2,382**
2008					
External revenues	$ 805	$ 342	$ -	$ -	$ 1,147
Intersegment revenues	3	-	-	(3)	-
Depreciation and amortization	50	27	-	-	77
Interest charges	16	5	-	-	21
Income taxes	5	34	-	-	39
Net income(a)	16	52	-	-	68
Capital expenditures	61	258	-	-	319
Total assets	1,214	1,081	-	1	2,296
2007					
External revenues	$ 732	$ 279	$ -	$ -	$ 1,011

Intersegment revenues	-	4	-	(4)	-
Depreciation and amortization	54	19	-	-	73
Interest charges	18	8	1	-	27
Income taxes	-	39	-	-	39
Net income[(a)]	9	65	-	-	74
Capital expenditures	64	190	-	-	254
Total assets	1,017	859	-	(9)	1,867

(a) Represents net income available to the common stockholder (CILCORP); 100% of CILCO's preferred stock dividends are included in the Illinois Regulated segment.

Additional Notes Relating to the Statement of Cash Flows:

Reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet for the year ended December 31, 2009:

Cash and Cash Equivalents at End of Period	$ 87,606,930
Related amounts on the Balance Sheet:	
Line 35 – Cash	$ 170,084
Line 37 – Working Fund	1,200
Line 38 – Temp Cash Investments	87,435,646
	$ 87,606,930

Amount of interest paid (net of amounts capitalized) = $23,172,220

Amount of income taxes paid, net = $14,796,353

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges Gas Swaps (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		591,952	591,952		
2		(784,864)	(784,864)		
3		192,912	192,912		
4		(591,952)	(591,952)	69,638,345	69,046,393
5					
6					
7					
8					
9				135,102,404	135,102,404
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,505,824,157	987,231,773
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,505,824,157	987,231,773
9	Leased to Others		
10	Held for Future Use	133,638	133,638
11	Construction Work in Progress	11,521,503	4,510,341
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	1,517,479,298	991,875,752
14	Accum Prov for Depr, Amort, & Depl	928,765,509	561,575,686
15	Net Utility Plant (13 less 14)	588,713,789	430,300,066
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	928,599,990	561,559,692
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	165,519	15,994
22	Total In Service (18 thru 21)	928,765,509	561,575,686
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	928,765,509	561,575,686

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
518,592,384					3
					4
					5
					6
					7
518,592,384					8
					9
					10
7,011,162					11
					12
525,603,546					13
367,189,823					14
158,413,723					15
					16
					17
367,040,298					18
					19
					20
149,525					21
367,189,823					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
367,189,823					33

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
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			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	26,656	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	26,656	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	4,922,677	7,541
49	(352) Structures and Improvements	5,376,025	
50	(353) Station Equipment	44,507,947	4,012,062
51	(354) Towers and Fixtures	16,651,816	921
52	(355) Poles and Fixtures	12,498,779	427,660
53	(356) Overhead Conductors and Devices	20,848,790	111,883
54	(357) Underground Conduit	235,792	
55	(358) Underground Conductors and Devices	713,442	
56	(359) Roads and Trails	29,192	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	105,784,460	4,560,067
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,137,097	92,237
61	(361) Structures and Improvements	7,217,815	79,671
62	(362) Station Equipment	110,868,991	7,783,614
63	(363) Storage Battery Equipment	4,504	
64	(364) Poles, Towers, and Fixtures	159,694,039	7,630,522
65	(365) Overhead Conductors and Devices	144,630,918	8,435,826
66	(366) Underground Conduit	60,888,055	515,533
67	(367) Underground Conductors and Devices	137,747,368	4,161,707
68	(368) Line Transformers	86,555,884	1,815,743
69	(369) Services	50,765,498	2,120,620
70	(370) Meters	21,248,028	2,734,663
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	12,589,292	390,200
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	795,347,489	35,760,336
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	838,593	
87	(390) Structures and Improvements	21,604,717	28,946
88	(391) Office Furniture and Equipment	3,770,427	793,239
89	(392) Transportation Equipment	14,755,302	1,539,623
90	(393) Stores Equipment	373,724	50,693
91	(394) Tools, Shop and Garage Equipment	3,711,056	166,602
92	(395) Laboratory Equipment	587,136	123,343
93	(396) Power Operated Equipment	1,559,360	129,824
94	(397) Communication Equipment	5,319,168	535,745
95	(398) Miscellaneous Equipment	25,563	4
96	SUBTOTAL (Enter Total of lines 86 thru 95)	52,545,046	3,368,019
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	225,378	-146,581
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	52,770,424	3,221,438
100	TOTAL (Accounts 101 and 106)	953,929,029	43,541,841
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	953,929,029	43,541,841

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
			26,656		4
			26,656		5
					6
					7
					8
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			4,930,218		48
		99,758	5,475,783		49
1,176,709		-99,758	47,243,542		50
			16,652,737		51
894		219,663	13,145,208		52
		5,058	20,965,731		53
			235,792		54
			713,442		55
			29,192		56
					57
1,177,603		224,721	109,391,645		58
					59
145		-224,721	3,004,468		60
			7,297,486		61
445,174		-2,684	118,204,747		62
	-4,504				63
322,076	4,504	2,048	167,009,037		64
576,965		-2,048	152,487,731		65
21,274			61,382,314		66
514,169			141,394,906		67
520,588		-25,168	87,825,871		68
2,431,658			50,454,460		69
4,505,588		1,906,283	21,383,386		70
					71
					72
297,799			12,681,693		73
					74
9,635,436		1,653,710	823,126,099		75
					76
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					78
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					80
					81
					82
					83
					84
					85
54,280			784,313		86
480,396		-12,578	21,140,689		87
30,101		457,239	4,990,804		88
1,060,668		127,988	15,362,245		89
2,952			421,465		90
180,247			3,697,411		91
			710,479		92
68,370		12,032	1,632,846		93
15,236		3,080	5,842,757		94
			25,567		95
1,892,250		587,761	54,608,576		96
					97
			78,797		98
1,892,250		587,761	54,687,373		99
12,705,289		2,466,192	987,231,773		100
					101
					102
					103
12,705,289		2,466,192	987,231,773		104

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	None				
2					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Grouped Items - Transmission			133,638
3				
4				
5				
6				
7				
8				
9				
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14				
15				
16				
17				
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21	Other Property:			
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46				
47	Total			133,638

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Physical Security - 2CHERRY Sub	715,387
2	Capacitor bank Program year 4	629,065
3	Peoria General Office Building 3rd Floor Renovations	509,960
4	Peoria General Office building - Replace Curtain Wall	388,491
5	Radnor 6 & 9 Reconfigure	357,142
6	Ameren.com Redesign (Build) - CIIL	276,295
7	Tazewell - Replace 6975 and 6951 Relays	239,481
8	Lincoln - Power Factor Improvements	179,465
9	Chester - Sectionalize	146,473
10	Northwest 6 Cable Replacement	143,005
11	Hauk - Sectionalize	122,593
12	Springfield - Ridge 2 Improvements	93,594
13	Elm Grove Sectionalize on L6951	85,359
14	Springfield - Mansfield 1 Improvements	84,468
15	Spring Bay Metamora Tie	73,403
16	Eastern - Replace L1354 Relays	69,672
17	Protective Device Coordination	60,930
18	Washington Office Renovations	60,508
19	Radnor 2 Rebuild Route 91	56,877
20	Minor Projects	218,173
21		
22		
23		
24		
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43	TOTAL	4,510,341

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	550,192,910	550,192,910		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	23,891,249	23,891,249		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,096,322	1,096,322		
7	Other Clearing Accounts	138,593	138,593		
8	Other Accounts (Specify, details in footnote):	275,026	275,026		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	25,401,190	25,401,190		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	12,650,864	12,650,864		
13	Cost of Removal	2,427,899	2,427,899		
14	Salvage (Credit)	739,702	739,702		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	14,339,061	14,339,061		
16	Other Debit or Cr. Items (Describe, details in footnote):	304,653	304,653		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	561,559,692	561,559,692		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	61,670,292	61,670,292		
26	Distribution	478,157,381	478,157,381		
27	Regional Transmission and Market Operation				
28	General	21,732,019	21,732,019		
29	TOTAL (Enter Total of lines 20 thru 28)	561,559,692	561,559,692		

Schedule Page: 219 Line No.: 8 Column: c

Other Accounts shown on Page 219, line 8

(1) Depreciation apportioned from electric	$	271,725
(2) Asset Retirement Obligation charged to Account 182		3,301
Total Other Accounts shown on Page 219, line 8	$	275,026

Schedule Page: 219 Line No.: 12 Column: c

Reconciliation of retirements shown on Schedule Page 207 with book costs of plant retired (Page 219)

Retirements per Schedule Page 207	$	12,705,289
Less: Retirements of non-depreciable property and other retirement adjustments		54,425
Total Book Cost of Plant Retired Charged to Reserve - Schedule Page 219, line 12	$	12,650,864

Schedule Page: 219 Line No.: 16 Column: c

Other (debit) credit items:

Electric plant transfers	$	304,653
Total other debit items Page 219, Line 16	$	304,653

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Ameren Energy Resources Generating Company	10/01/03		437,492,201
2	Equity in Undistributed Earnings			
3				
4				
5				
6				
7				
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41				
42	Total Cost of Account 123.1 $ 292,443,381		TOTAL	437,492,201

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
113,500,988		550,993,189		1
				2
				3
				4
				5
				6
				7
				8
				9
				10
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				41
113,500,988		550,993,189		42

Name of Respondent Central Illinois Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/19/2010	Year/Period of Report End of 2009/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	34,614		Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			Electric
8	Transmission Plant (Estimated)	264,142	251,172	Electric
9	Distribution Plant (Estimated)	5,178,981	4,960,313	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,119,920	2,317,363	Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	7,563,043	7,528,848	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	327,844	396,865	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	7,925,501	7,925,713	

Schedule Page: 227 Line No.: 11 Column: b

Other Material and Supplies relates to distribution of gas.

Schedule Page: 227 Line No.: 11 Column: c

Other Material and Supplies relates to distribution of gas.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2011		2012		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2011		2012		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
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16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
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43						
44						
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46						
47						
48						
49	TOTAL					

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Interconnection Study (internal)	14	561.7		
3					
4					
5					
6					
7					
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21	**Generation Studies**				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Other Post Employment Benefits	23,863,249	738,000	234,253	18,589,383	6,011,866
2						
3	Pensions	101,154,169	6,110,891	234,253	20,004,364	87,260,696
4						
5	Temporary Differences	336,959	176,053	410	66,571	446,441
6						
7	Percentage Income Payment Program Tariff		64			64
8						
9	Illinois Bad Debt Rider		4,365,000	407	74,000	4,291,000
10						
11	Electric Post 2006 Rate Case	287,376		928	287,376	
12	Amortization period of 3 years starting					
13	January 2007					
14						
15	Asset Retirement Obligation - Regulated Asset	958,438	69,289	390,399	23,378	1,004,349
16						
17	Illinois Electric and Gas Rate Cases	1,225,399		928	346,404	878,995
18	Expenses - 2007					
19	Amort period of 3 yrs starting October 2008					
20						
21						
22	Derivative Mark-to-Market Regulatory Asset		68,381,435	245	51,432,261	16,949,174
23						
24	Illinois Financial Contracts	29,253,535	77,701,634	245	39,704,693	67,250,476
25						
26	Auction Improvement/2008 Auction Design	74,877		407	27,228	47,649
27	Costs					
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	157,154,002	157,542,366		130,555,658	184,140,710

Schedule Page: 232 Line No.: 1 Column: a

Commission Order, Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 3 Column: a

Commission Order, Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 5 Column: a

Commission Order, Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 7 Column: a

Illinois Senate Bill 1918

Schedule Page: 232 Line No.: 9 Column: a

Illinois Senate Bill 1918

Schedule Page: 232 Line No.: 11 Column: a

Commission Order, 06-0070-06-072 (Cons.)

Schedule Page: 232 Line No.: 15 Column: a

Commission Order, Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 17 Column: a

Commission Order, Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 22 Column: a

Commission Order, Docket No., 08-0623

Schedule Page: 232 Line No.: 24 Column: a

Commission Order, Docket No., 09-0373

Schedule Page: 232 Line No.: 26 Column: a

Commission Order, Docket Nos., 07-0585-07-0590 (Cons.)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	$800M Credit Facility Fee		2,906,402	921	744,877	2,161,525
2						
3	Work in Progress	111,130	165,558	Various	238,678	38,010
4						
5	Coal Tar Rider	8,616,941	5,181,182	495	13,751,063	47,060
6						
7	Margin for Natural Gas Futures	6,150,983	11,636,630	131	17,787,613	
8						
9	Electric Energy Efficiency &					
10	Demand Response Programs	-692,229	3,647,743	456	3,994,585	-1,039,071
11						
12	Gas Energy Efficiency	46,351	693,048	495	678,239	61,160
13						
14	IBNR Workers Compensation	-37,536		925		-37,536
15						
16	2008/2009 Electric/Gas					
17	Rate Case	18,113	1,026,805	928	8,997	1,035,921
18						
19						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	14,213,753				2,267,069

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	ADIT Unamortized Investment Tax Credit	1,020,305	772,944
3	Other Non-property temporary differences	37,941,441	36,601,752
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	38,961,746	37,374,696
9	Gas		
10	ADIT Unamortized Investment Tax Credit	1,173,744	1,028,468
11	Other Non-property temporary differences	12,718,687	16,488,688
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	13,892,431	17,517,156
17	Other (Specify)		41,999
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	52,854,177	54,933,851

Notes

FOOTNOTE DATA

Schedule Page: 234 Line No.: 8 Column: b

Total Electric Account 190	$	38,961,746
SFAS No. 109 Unamortized Investment Tax Credit		1,020,305
Electric Account 190 Excluding SFAS No. 109 ITC	$	37,941,441

Functionalization of Account 190 Excluding SFAS No. 109 ITC End of Year

Production	0.00%
Transmission	2.68%
Distribution	69.50%
General	27.82%

Schedule Page: 234 Line No.: 8 Column: c

Total Electric Account 190	$	37,374,696
Unamortized Investment Tax Credit		772,944
Electric Account 190 Excluding ITC	$	36,601,752

Functionalization of Account 190 Excluding ITC Beginning of Year

Transmission	2.86%
Distribution	58.63%
General	38.51%

Schedule Page: 234 Line No.: 17 Column: a

Other includes deferrals relating to Other Income and Deductions.

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock, Without Par Value	20,000,000		
2	Total Common	20,000,000		
3	Preferred Stock			
4	Cumulative, Par Value $100 Per Share	1,500,000		
5	Series			
6	4.5%		100.00	110.00
7	4.64%		100.00	102.00
8				
9	Class A	3,500,000		
10	Series			
11	5.85% (Shares redeemed July 2008)		100.00	100.00
12				
13	Preference Stock, Without Par Value	2,000,000		
14	Total Preferred	7,000,000		
15				
16				
17				
18				
19				
20				
21				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
13,563,871	185,661,496					1
13,563,871	185,661,496					2
						3
						4
						5
111,264	11,126,400					6
79,940	7,994,000					7
						8
						9
						10
						11
						12
						13
191,204	19,120,400					14
						15
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received From Stockholders (Account 208)	
2		
3		
4		
5		
6		
7		
8	Miscellaneous Paid-In-Capital - 1/1/09	243,167,330
9		
10		
11		
12	Capital Contribution from CILCORP	51,000,000
13		
14	Subtotal (Account 211) - 12/31/09	294,167,330
15		
16	Gain or Loss on Cancellation of Reacquired Capital Stock	
17	(Account 210)	
18		
19	Balance: Beginning of Year	
20	Debits:	
21	Credits:	
22	Balance: End of Year	
23		
24		
25		
26		
27		
28		
29		
30		
31		
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39		
40	TOTAL	294,167,330

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3	None	
4		
5		
6		
7		
8		
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16		
17		
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19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - Bonds - First Morgage Bonds		
2	Series % Due		
3	6.20% 2016	54,000,000	584,666
4			190,620 D
5	6.70% 2036	42,000,000	578,762
6			231,420 D
7	8.875% 2013	150,000,000	1,279,491
8			4,500 D
9	ACCOUNT 221 - Bonds - Pollution Control		
10	Refunding G 6.2% 2012	1,000,000	78,823
11			5,820 D
12	Refunding H 5.90% 2023	32,000,000	400,765
13			
14			
15			
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26			
27			
28			
29			
30			
31			
32			
33	TOTAL	279,000,000	3,354,867

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
06/14/06	06/15/16	07/01/06	06/01/16	54,000,000	3,348,000	3
						4
06/14/06	06/15/36	07/01/06	06/01/36	42,000,000	2,814,000	5
						6
12/09/08	12/15/13	12/01/08	12/01/13	150,000,000	13,312,500	7
						8
						9
08/01/92	11/01/12	08/01/92	11/01/12	1,000,000	62,000	10
						11
08/01/93	08/01/23	08/01/93	08/01/23	32,000,000	1,888,000	12
						13
						14
						15
						16
						17
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				279,000,000	21,424,500	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	135,102,404
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax	-14,221,099
11	Deferred Income Taxes	21,817,254
12	Other*	22,658,489
13		
14	Income Recorded on Books Not Included in Return	
15	Equity in Earnings of Subsidiaries	113,500,988
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Plant Temporary Differences	40,183,516
21	Other*	42,331,982
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-30,659,438
28	Show Computation of Tax:	
29	Federal Income Tax	-10,730,803
30	Adjustments	-3,490,296
31		
32	Total Federal Income Tax	-14,221,099
33		
34	*See Attached Notes	
35		
36		
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Schedule Page: 261 Line No.: 10 Column: b

The consolidated tax is allocated to each member of the consolidated tax group on the basis of the ratio of the estimated ultimate tax of each Company, computed on a separate return basis, to the aggregate taxes of the Companies on such basis.

Ameren Development Company	(10,630,213)
Ameren Energy Resources, LLC	(2,405,281)
Ameren Energy Fuels and Services Company	(1,422,704)
CLC Aircraft Leasing Company	-
Ameren Corporation	16,359,896
Ameren Services	3,543,923
Ameren Energy Resources Generation Company	35,386,094
CILCORP	(27,010,666)
AmerenCILCO	(14,221,099)
AmerenCIPS	12,777,824
CIPSCO Leasing Company	994,050
Coffeen and Western Railroad	(1,706,977)
Electric Energy Inc.	(8,854,881)
Energy Risk Assurance Company	(14,548)
ESE Land Corporation	-
Ameren Energy Generating	32,101,605
Ameren Energy Marketing	13,302,778
Illinois Material Supply Company	(153,285)
AmerenIP	(6,636,516)
Illinois Transmission Company	(915,805)
Joppa and Eastern Railroad	131
Missouri Central Railroad	(93,898)
Midwest Electric Power, Inc.	184,738
Met-South, Inc.	(113,139)
Missouri Risk Assurance	(17,417)
Medina Valley CoGen, LLC	1,396,746
QST Enterprises, Inc.	(193,485)
AmerenUE	(117,342,572)
Elimination	1,736,891
Total	(73,947,810)

Schedule Page: 261 Line No.: 12 Column: b

Deductions Recorded on books Not Deducted for Return – Other

Country Club and Entertainment Expense	$ 2,677
Disallowance of Meals	47,031
Lobbying Expenses	645,640
Penalties Expenses	48,749
Active VEBA	78,864
Change in Legal Expense Reserve	6,177
Change in Uncollectible Accounts	233,123
Charitable Contribution 0 Rate Case	1,464,000
Book/Tax (OPEB)	2,600,446
IBNR	510,788
Pension Expense Allowed/Disallowed	11,074,512
Tax Reserve Interest – Noncurrent	10,590
Book/Tax Loss on Reacquired Debt	356,292

Environmental Remediation	871,625	
Gas Storage Fields	1,987,493	
Manufactured Gas Clean-up	1,572,300	
RSG Regulated Asset/Liability	289,561	
State Income Tax Adjustment	858,621	
TOTAL deductions Recorded on Books Not Deducted for Return – Other		$ 22,658,489

Schedule Page: 261 Line No.: 21 Column: b

Deductions on Return Not Charged Against Book Income

Company Owned Life Insurance	$ 5,328,974	
Medicare Prescription Drug	1,270,000	
Preferred Dividend Paid Credit	200,275	
Asset Retirement Obligation	19,340,302	
Change in Injuries & Damages	2,049,518	
Change in Obsolete Inventory	246,457	
Deferred Compensation	679,092	
Over/Under Accrual of State Income Taxes	1,228,235	
Sec. 481(a) Adjustment – Over/Under Accrual of Taxes	131,938	
Tax Reserve Interest – Current	1,165,868	
Mark-to-Market Derivative Transactions	5,795,385	
Rate Case Expenses	384,028	
Illinois Bad Debt Rider	4,291,000	
Prepaid Insurance	220,910	
TOTAL Deductions on Return Not Charged Against Book Income – Other		$ 42,331,982

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Income Taxes					
2	Federal	7,002,501		-14,221,099	6,479,277	-52,258
3	State					
4	Illinois	842,668		431,230	1,187,000	
5	Kansas					
6	Missouri					
7	Total Income Taxes	7,845,169		-13,789,869	7,666,277	-52,258
8						
9	Other Taxes:					
10	Payroll Taxes:					
11	SS & Medicare-2008					
12	SS & Medicare-2009			6,130,383	6,130,383	
13	Federal Unemployment-2008			331	331	
14	Federal Unemployment-2009			57,269	57,269	
15	Illinois Unemployment - 2008			1,190	1,190	
16	Illinois Unemployment - 2009			111,092	111,092	
17	Missouri Unemployment -					
18	Missouri Unemployment -			6,143	6,143	
19	St. Louis Payroll Expns-2008					
20	St. Louis Payroll Expns-2009			5,683	4,183	
21	Subtotal Payroll Taxes			6,312,091	6,310,591	
22						
23	Property Taxes:					
24	IL Electric Distrib - 2006			-609,279	-609,279	
25	IL Electric Distrib - 2007			-101,015	-101,015	
26	IL Electric Distrib - 2008	246,728		-73,299	173,429	
27	IL Electric Distrib - 2009			5,750,000	5,924,880	
28	IL Invested Capital - 2008	92,836		98,139	190,975	
29	IL Invested Capital - 2009			1,150,000	1,248,140	
30	IL Real Estate - 2008	652,770		24,213	676,983	
31	IL Real Estate - 2009			675,000	2,231	
32	Kansas PP - 2009			245,000		
33	Oklahoma PP - 2009			12,917	12,917	
34	Subtotal Property Taxes	992,334		7,171,676	7,519,261	
35						
36	Gross Receipts Taxes:					
37	IL Assistance Charges - 2008	368,775		-8,713	360,062	
38	IL Assistance Charges - 2009			4,697,714	4,259,939	
39	ICC Gross Revenue - 2008					
40	ICC Gross Revenue - 2009			257,088	257,088	
41	TOTAL	10,610,112		11,179,308	32,915,385	-52,258

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	IL Gross	888,677		-24,307		
2	IL Gas Revenue - 2008	432,817		-338,146	94,671	
3	IL Gas Revenue - 2009			5,933,626	5,476,320	
4	IL Municipal - 2008	82,340		16,799	99,139	
5	IL Municipal - 2009			573,725	494,413	
6	Subtotal Gross Receipts	1,772,609		11,107,786	11,041,632	
7						
8	Franchise & Misc Taxes:					
9	Federal Excise - 2009			188	188	
10	IL Corporate Franchise - 2009			377,436	377,436	
11	Subtotal Franchise & Misc			377,624	377,624	
12						
13	Summary by Jurisdiction:					
14	See footnote					
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	10,610,112		11,179,308	32,915,385	-52,258

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
	13,750,133	-11,912,801			-2,308,298	2
						3
86,898		234,292			196,938	4
						5
						6
86,898	13,750,133	-11,678,509			-2,111,360	7
						8
						9
						10
						11
		3,258,460			2,871,923	12
		-2,106			2,437	13
		43,825			13,444	14
		-15,248			16,438	15
		32,718			78,374	16
						17
		6,143				18
						19
1,500		5,683				20
1,500		3,329,475			2,982,616	21
						22
						23
		-609,279				24
		-101,015				25
		-73,299				26
-174,880		5,750,000				27
					98,139	28
-98,140					1,150,000	29
		175,304			-151,091	30
672,769		558,525			116,475	31
245,000					245,000	32
					12,917	33
644,749		5,700,236			1,471,440	34
						35
						36
		-7,381			-1,332	37
437,775		2,558,247			2,139,467	38
						39
					257,088	40
2,571,910	13,750,133	256,504			10,922,804	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
864,370		108,891			-133,198	1
					-338,146	2
457,306					5,933,626	3
					16,799	4
79,312					573,725	5
1,838,763		2,659,757			8,448,029	6
						7
						8
		188				9
		245,357			132,079	10
		245,545			132,079	11
						12
						13
						14
						15
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						17
						18
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						35
						36
						37
						38
						39
						40
2,571,910	13,750,133	256,504			10,922,804	41

Schedule Page: 262 Line No.: 2 Column: f

Adjustments made to uncertain tax positions.

Schedule Page: 262.1 Line No.: 14 Column: a

Kind of Tax	Taxes Accrued	Taxes Charged During Year	Taxes Paid During Year	Adjust	Taxes Accrued	Prepaid Taxes	Electric	Other
Federal Taxes	7,002,501	(8,032,928)	12,667,448	(52,258)	0	13,750,133	(8,612,434)	579,506
Illinois Taxes	3,525,271	18,351,969	19,631,969	0	2,246,098	0	8,857,112	9,494,857
Illinois Municipal Taxes	82,340	590,524	593,552	0	79,312	0	0	590,524
Kansas Taxes	0	245,000	0	0	245,000	0	0	245,000
Missouri Taxes	0	6.143	6.143	0	0	0	6,143	0
Oklahoma Taxes	0	12.917	12.917	0	0	0	0	12,917
St. Louis Taxes	0	5,683	4,183	0	1,500	0	5,683	0
	10,610,112	11,179,308	32,915,385	(52,258)	2,571,910	13,750,133	256,504	10,922,804

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%				411.5		
3	4%	669				643	
4	7%						
5	10%	1,549,065				375,074	
6							
7							
8	TOTAL	1,549,734				375,717	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	3%				411.5		
13	4%	2,079				1,462	
14	7%	5,905				4,004	
15	10%	1,774,807				215,194	
16							
17	TOTAL	1,782,791				220,660	
18							
19							
20							
21							
22							
23							
24							
25							
26							
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44							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
26	32 Years		3
			4
1,173,991	32 Years		5
			6
			7
1,174,017			8
			9
			10
			11
			12
617	35 Years		13
1,901	35 Years		14
1,559,613	35 Years		15
			16
1,562,131			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
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			44
			45
			46
			47
			48

Schedule Page: 266 Line No.: 8 Column: b

Functionalization of Account 255 Total Electric Balance Beginning of Year

Transmission	11.29%
Distribution	82.90%
General	5.81%

Schedule Page: 266 Line No.: 8 Column: h

Functionalization of Account 255 Total Electric End of Year

Transmission	11.34%
Distribution	81.53%
General	7.13%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Contaminated Facilities Liability	7,950,000	186	7,800,000		150,000
2						
3	Accrued Pension Liability	19,087,639	926	9,711,000	14,087,000	23,463,639
4						
5	Deferred Compensation	2,131,095	926	1,510,161	722,837	1,343,771
6						
7	Deferred Compensation-	4,462,951	926	471,488	2,693,000	6,684,463
8	Supplemental					
9	Deferred Earnings	6,502,520	various	556,896	579,813	6,525,437
10						
11	Environmental Liability		131-001	3,961		-3,961
12						
13	Adjustment for Pension	88,708,410	182	15,485,403	6,110,891	79,333,898
14						
15	Other Deferred Credit Deposit					
16	Requests	1,906,623	142-001	4,838,378	4,734,089	1,802,334
17						
18	Post Retirement Benefits	61,824,287	926	8,614,768	11,159,332	64,368,851
19						
20	Post Retirement Benefits-Part D	-2,068,763	926	1,270,000	1,239,491	-2,099,272
21						
22	Adjustment for Other Post					
23	Retirement Benefits	26,991,476	182	16,733,360		10,258,116
24						
25	Adjustment for Other Post					
26	Retirement Benefits, Medicare					
27	Part D	-9,233,000	182	352,000	2,211,272	-7,373,728
28						
29	Tax Interest Accrual	10,824	431		10,590	21,414
30						
31	Liability for Unrecognized Tax					
32	Benefits		236	291	54,942	54,651
33						
34	Illinois Rate Relief Refunds		456	463,450	1,066,687	603,237
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	208,274,062		67,811,156	44,669,944	185,132,850

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
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							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	75,118,922	7,054,300	463,668
3	Gas	8,425,908	6,647,013	515,081
4	Other Income and Deductions	-3,737,312		
5	TOTAL (Enter Total of lines 2 thru 4)	79,807,518	13,701,313	978,749
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	79,807,518	13,701,313	978,749
10	Classification of TOTAL			
11	Federal Income Tax	66,380,817	11,933,661	668,381
12	State Income Tax	13,426,701	1,767,652	310,368
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		282		282		81,709,554	2
		282		282		14,557,840	3
1,829,330	168,449	282		282		-2,076,431	4
1,829,330	168,449					94,190,963	5
							6
							7
							8
1,829,330	168,449					94,190,963	9
							10
1,789,683	131,225					79,304,555	11
39,647	37,224					14,886,408	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: b

Electric Account 282 $ 75,118,922

Functionalization of Account 282 Total Electric Balance Beginning of Year

Transmission	11.29%
Distribution	82.90%
General	5.81%

Schedule Page: 274 Line No.: 2 Column: k

Electric Account 282 $ 81,709,554

Functionalization of Account 282 Total Electric Balance End of Year

Transmission	11.34%
Distribution	81.53%
General	7.13%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		-6,576,226	9,926,285	1,580,307
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	-6,576,226	9,926,285	1,580,307
10	Gas			
11		-4,888,217	5,099,332	2,609,199
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-4,888,217	5,099,332	2,609,199
18	Other Income and Deductions	641,477		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	-10,822,966	15,025,617	4,189,506
20	Classification of TOTAL			
21	Federal Income Tax	-8,685,858	12,262,773	3,419,145
22	State Income Tax	-2,137,108	2,762,844	770,361
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						1,769,752	3
							4
							5
							6
							7
							8
						1,769,752	9
							10
		190	1,714,410	190	4,119,209	6,715	11
							12
							13
							14
							15
							16
			1,714,410		4,119,209	6,715	17
19,805	90,294			190	41,999	612,987	18
19,805	90,294		1,714,410		4,161,208	2,389,454	19
							20
16,163	73,742		1,399,164		3,361,772	2,062,799	21
3,642	16,552		315,246		799,436	326,655	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 9 Column: b

Electric Account 283	$	(6,576,226)

Functionalization of Account 283 Total Electric Balance Beginning of Year

Transmission	11.04%
Distribution	82.75%
General	6.21%

Schedule Page: 276 Line No.: 9 Column: k

Electric Account 283	$	1,769,752

Functionalization of Account 283 Total Electric Balance End of Year

Transmission	10.26%
Distribution	79.08%
General	10.66%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Unamortized Investment Tax Credits	2,194,050	190	392,638		1,801,412
2						
3						
4						
5	Excess Deferred Depreciation	3,579,142	411	1,457,613	78,877	2,200,406
6						
7						
8						
9	Derivative Mark-to-Market Regulatory Liability	(24,745,963)	245	17,293,767	45,081,047	3,041,317
10						
11						
12						
13	Regulatory Liability Resulting From	6,078,774	190	1,455,845	231,748	4,854,677
14	Pension and OPEB Adjustments					
15						
16						
17	Illinois Bad Debt Rider				188,000	188,000
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-12,893,997		20,599,863	45,579,672	12,085,812

Schedule Page: 278 Line No.: 1 Column: a

Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 278 Line No.: 5 Column: a

Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 278 Line No.: 9 Column: a

Commission Order, Docket No., 08-0623

Schedule Page: 278 Line No.: 13 Column: a

Docket Nos., 07-0585-07-0590 (Cons.)

Schedule Page: 278 Line No.: 17 Column: a

Illinois Senate Bill 1918

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	183,429,078	196,162,409
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	93,361,418	106,636,898
5	Large (or Ind.) (See Instr. 4)	8,987,884	77,953,164
6	(444) Public Street and Highway Lighting	2,282,526	2,388,645
7	(445) Other Sales to Public Authorities	-51	-24,883
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	288,060,855	383,116,233
11	(447) Sales for Resale	16,681	28,645
12	TOTAL Sales of Electricity	288,077,536	383,144,878
13	(Less) (449.1) Provision for Rate Refunds	6,939,536	7,287,451
14	TOTAL Revenues Net of Prov. for Refunds	281,138,000	375,857,427
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,170,030	2,410,659
17	(451) Miscellaneous Service Revenues	39,738	19,548
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,229,186	1,860,522
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	87,782,420	23,498,008
22	(456.1) Revenues from Transmission of Electricity of Others	7,316,781	13,387,767
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	98,538,155	41,176,504
27	TOTAL Electric Operating Revenues	379,676,155	417,033,931

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
1,980,263	2,065,882	187,544	188,770	2
				3
1,914,077	1,988,261	23,237	24,865	4
1,822,796	2,436,254	147	155	5
23,969	24,408	548	544	6
197	-604	9	9	7
				8
				9
5,741,302	6,514,201	211,485	214,343	10
				11
5,741,302	6,514,201	211,485	214,343	12
				13
5,741,302	6,514,201	211,485	214,343	14

Line 12, column (b) includes $ -7,645,000 of unbilled revenues.
Line 12, column (d) includes 13,459 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: d

The megawatthours sold reported amounts include megawatthours delivered to delivery service customers (non-energy sales) as follows:

	Current Year	Prior Year
(440) Residential	6	-
(442) Small or Commercial	1,105,116	1,081,927
(442) Large or Industrial	1,650,678	1,392,998
(445) Other Sales to Public Authorities	132	- -
	2,755,932	2,474,925

Schedule Page: 300 Line No.: 21 Column: b

Account 456 other electric revenue includes the following:

Energy Efficiency	$	(3,576,505)
Rate Relief Generator Reimbursements		14,914,099
Intercompany Billings		76,435,066
Other		9,760
	$	87,782,420

Schedule Page: 300 Line No.: 21 Column: c

In 2008, account 456.1 included only energy charges per pages 328-330. We have adjusted the amount to include other revenues from transmission of electricity for others as detailed in the 2008 FERC Form 1 filing per pages 328-330. These amounts were previously reported in account 456.

Account 456 other electric revenue includes the following:

Energy Efficiency	$	(1,290,811)
Rate Relief Generator Reimbursements		21,772,470
Intercompany Billings		1,076,656
Other		1,939,693
	$	23,498,008

Schedule Page: 300 Line No.: 22 Column: c

In 2008, account 456.1 included only energy charges per pages 328-330. We have adjusted the amount to include other revenues from transmission of electricity for others as detailed in the 2008 FERC Form 1 filing per pages 328-330. These amounts were previously reported in account 456.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential	-6	-406			0.0677
2	Outdoor Protective Lighting	-4	-1,475			0.3688
3	Space Heating	-1	-52			0.0520
4	Total (440) Residential Sales	-11	-1,933			0.1757
5	Commercial General Service	-1	-53			0.0530
6	Outdoor Protective Lighting		-132			
7	Limited Off-Peak Service					
8	Comm Gen Service Sec-No Dmd	-7	-476			0.0680
9	Total Commercial	-8	-661			0.0826
10	Industrial	14,401	1,447,624	1	14,401,000	0.1005
11	Unbilled	-47,751	-3,286,000			0.0688
12	Total Industrial	-33,350	-1,838,376	1	-33,350,000	0.0551
13						
14	Residential BGS-1	1,969,215	110,167,264	187,544	10,500	0.0559
15	Residential BGS-1-Unbilled	4,040	-919,000			-0.2275
16	Total Residential BGS-1	1,973,255	109,248,264	187,544	10,522	0.0554
17						
18	Residential DS-1		73,700,310			
19	Residential DS-1-Unbilled		279,000			
20	Total Residential DS-1		73,979,310			
21						
22	Residential RTP-1	7,013	203,437			0.0290
23	Total Residential RTP-1	7,013	203,437			0.0290
24						
25	Commercial BGS-2	591,155	43,221,544	19,870	29,751	0.0731
26	Commercial BGS-2-Unbilled	-3,066	-565,000			0.1843
27						
28	Commercial BGS-3	176,735	11,676,865	264	669,451	0.0661
29	Commercial BGS-3-Unbilled	-3,703	-344,000			0.0929
30						
31	Commercial BGS-4					
32	Commercial BGS-4-Unbilled					
33	Total Commercial BGS	761,121	53,989,409	20,134	37,803	0.0709
34						
35	Commercial DS-2		22,162,577			
36	Commercial DS-2-Unbilled		93,000			
37						
38	Commercial DS-3		12,710,744			
39	Commercial DS-3-Unbilled		270,000			
40						
41	TOTAL Billed	5,727,843	295,705,855	211,485	27,084	0.0516
42	Total Unbilled Rev.(See Instr. 6)	13,459	-7,645,000	0	0	-0.5680
43	TOTAL	5,741,302	288,060,855	211,485	27,148	0.0502

Name of Respondent Central Illinois Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/19/2010	Year/Period of Report End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial DS-4		2,346,991			
2	Commercial DS-4-Unbilled		181,000			
3	Total Commercial DS		37,764,312			
4						
5	Commercial RTP-2	3,552	125,139	108	32,889	0.0352
6						
7	Commercial RTP-3	18,067	644,151	14	1,290,500	0.0357
8						
9	Commercial RTP-L	22,022	760,068	3	7,340,667	0.0345
10	Commercial BGS RTP-L-Unbilled	4,207	79,000			0.0188
11	Total Commercial RTP-L	47,848	1,608,358	125	382,784	0.0336
12						
13	Industrial BGS-2	2,975	214,518	44	67,614	0.0721
14	Industrial BGS-2-Unbilled	-4	-2,000			0.5000
15						
16	Industrial BGS-3	13,909	926,033	14	993,500	0.0666
17	Industrial BGS-3-Unbilled	-736	-58,000			0.0788
18						
19	Industrial BGS-4					
20	Industrial BGS-4-Unbilled					
21	Total Industrial BGS	16,144	1,080,551	58	278,345	0.0669
22						
23	Industrial DS-2		131,478			
24	Industrial DS-2-Unbilled					
25						
26	Industrial DS-3		995,327			
27	Industrial DS-3-Unbilled		1,000			
28						
29	Industrial DS-4		5,397,585			
30	Industrial DS-4-Unbilled		97,000			
31	Total Industrial DS		6,622,390			
32						
33	Industrial RTP-L	188,592	6,553,319	5	37,718,400	0.0347
34	Industrial RTP-L-Unbilled	732	-3,430,000			-4.6858
35	Total Industrial RTP-L	189,324	3,123,319	5	37,864,800	0.0165
36						
37						
38	Street Lighting BGS	24,398	856,487	548	44,522	0.0351
39	Street Lighting BGS-Unbilled	-429	-22,000			0.0513
40	Total Street Lighting BGS	23,969	834,487	548	43,739	0.0348
41	TOTAL Billed	5,727,843	295,705,855	211,485	27,084	0.0516
42	Total Unbilled Rev.(See Instr. 6)	13,459	-7,645,000	0	0	-0.5680
43	TOTAL	5,741,302	288,060,855	211,485	27,148	0.0502

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	Street Lighting DS		1,467,050			
3	Street Lighting DS-Unbilled		-19,000			
4	Total Street Lighting DS		1,448,050			
5						
6	Public Authority BGS	70	107	4	17,500	0.0015
7	Public Authority BGS-Unbilled	-5				
8	Total Public Authority BGS	65	107	4	16,250	0.0016
9						
10	Public Authority DS		-158			
11	Public Authority DS-Unbilled					
12	Total Public Authority DS		-158			
13						
14	ARES Commercial	1,080,337		2,978	362,773	
15	ARES Commercial-Unbilled	24,779				
16	Total ARES commercial	1,105,116		2,978	371,093	
17						
18	ARES Industrial	1,615,287		83	19,461,289	
19	ARES Industrial-Unbilled	35,391				
20	Total ARES Industrial	1,650,678		83	19,887,687	
21						
22	Public Street/Highway Lighting		-11			
23	Unbilled					
24						
25	Total Public Street/Highway Light		-11			
26						
27	ARES Non-Ameren Affiliate Res	5				
28	ARES Non-Am Affiliate Resid-Unbil	1				
29	Total ARES Non-AM Affiliate	6				
30	ARES Public Authority	129		5	25,800	
31	ARES Public Authority-Unbilled	3				
32						
33	Total ARES Public Authority	132		5	26,400	
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	5,727,843	295,705,855	211,485	27,084	0.0516
42	Total Unbilled Rev.(See Instr. 6)	13,459	-7,645,000	0	0	-0.5680
43	TOTAL	5,741,302	288,060,855	211,485	27,148	0.0502

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Midwest Independent System Operator	OS	CST1			
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		11,637	5,044	16,681	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
0	0	11,637	5,044	16,681	
0	**0**	**11,637**	**5,044**	**16,681**	

Name of Respondent Central Illinois Light Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/19/2010	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: j

Detail of the Other Charges resulting from sales to the Midwest Independent System Operator are as follows:

Inadvertent Energy	$	5,044
Total	$	5,044

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		-260
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		-260
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		-1,953
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		-1,953
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		-2,213
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		27,516
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses	38	
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	38	27,516
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	-300	64,811
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	-300	64,811
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	-262	92,327
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	169,453,938	273,053,574
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	-1,239,787	3,610,108
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	168,214,151	276,663,682
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	168,213,889	276,753,796
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	170,360	156,671
84	(561) Load Dispatching	50,523	63,692
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	324,169	208,734
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	493,838	639,396
89	(561.5) Reliability, Planning and Standards Development	57,650	43,065
90	(561.6) Transmission Service Studies		8
91	(561.7) Generation Interconnection Studies	14	73
92	(561.8) Reliability, Planning and Standards Development Services	35,508	42,974
93	(562) Station Expenses		
94	(563) Overhead Lines Expenses	-4,279	
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	1,075,173	757,464
97	(566) Miscellaneous Transmission Expenses	471,476	-123,224
98	(567) Rents	247,485	
99	TOTAL Operation (Enter Total of lines 83 thru 98)	2,921,917	1,788,853
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	82,402	23,844
102	(569) Maintenance of Structures	71,835	59,355
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	320,965	206,268
108	(571) Maintenance of Overhead Lines	1,275,821	890,473
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	4,461	51,336
111	TOTAL Maintenance (Total of lines 101 thru 110)	1,755,484	1,231,276
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	4,677,401	3,020,129

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	191,494	143,511
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	191,494	143,511
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	191,494	143,511
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,142,664	1,262,842
135	(581) Load Dispatching	1,501,760	1,349,246
136	(582) Station Expenses	198,070	228,413
137	(583) Overhead Line Expenses	1,021,814	1,178,910
138	(584) Underground Line Expenses	335,013	463,497
139	(585) Street Lighting and Signal System Expenses	318,440	303,492
140	(586) Meter Expenses	1,790,733	1,772,148
141	(587) Customer Installations Expenses	292,321	298,184
142	(588) Miscellaneous Expenses	5,384,650	5,375,303
143	(589) Rents	11,454	287,926
144	TOTAL Operation (Enter Total of lines 134 thru 143)	11,996,919	12,519,961
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	249,272	364,236
147	(591) Maintenance of Structures	387,282	473,031
148	(592) Maintenance of Station Equipment	2,834,830	2,337,974
149	(593) Maintenance of Overhead Lines	9,461,274	14,175,987
150	(594) Maintenance of Underground Lines	1,077,085	971,873
151	(595) Maintenance of Line Transformers	168,543	70,718
152	(596) Maintenance of Street Lighting and Signal Systems	358,267	333,642
153	(597) Maintenance of Meters	41,386	4,228
154	(598) Maintenance of Miscellaneous Distribution Plant	450,431	772,484
155	TOTAL Maintenance (Total of lines 146 thru 154)	15,028,370	19,504,173
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	27,025,289	32,024,134
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	505	8,009
160	(902) Meter Reading Expenses	2,393,441	1,922,600
161	(903) Customer Records and Collection Expenses	5,625,795	5,468,977
162	(904) Uncollectible Accounts	2,231,650	3,330,000
163	(905) Miscellaneous Customer Accounts Expenses	81,419	228,479
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	10,332,810	10,958,065

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	70,831	78,553
168	(908) Customer Assistance Expenses	331,164	250,764
169	(909) Informational and Instructional Expenses	397,768	588,955
170	(910) Miscellaneous Customer Service and Informational Expenses	64,814	160,012
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	864,577	1,078,284
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	39,963	127,059
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	1,702	6,415
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	41,665	133,474
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	12,923,441	9,741,330
182	(921) Office Supplies and Expenses	61,518,367	3,011,952
183	(Less) (922) Administrative Expenses Transferred-Credit	445,589	329,807
184	(923) Outside Services Employed	3,430,745	4,612,902
185	(924) Property Insurance	770,353	566,007
186	(925) Injuries and Damages	858,830	780,617
187	(926) Employee Pensions and Benefits	13,737,574	3,980,881
188	(927) Franchise Requirements	1,472,184	1,443,177
189	(928) Regulatory Commission Expenses	1,245,819	1,374,550
190	(929) (Less) Duplicate Charges-Cr.	1,330,606	1,391,421
191	(930.1) General Advertising Expenses	102,110	302,502
192	(930.2) Miscellaneous General Expenses	534,643	653,327
193	(931) Rents	2,528,046	2,481,683
194	TOTAL Operation (Enter Total of lines 181 thru 193)	97,345,917	27,227,700
195	Maintenance		
196	(935) Maintenance of General Plant	477,943	382,547
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	97,823,860	27,610,247
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	309,170,985	351,721,640

Schedule Page: 320 Line No.: 84 Column: b

Account 561 includes 561.BA cost of $50,523.

Schedule Page: 320 Line No.: 84 Column: c

Account 561 includes 561.BA cost of $63,692.

Schedule Page: 320 Line No.: 182 Column: b

Amount includes $56,801,109 of support service expenses related to the Ameren Illinois Utilities Services Agreement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	American Electric Power Service	OS				
2	Boston Pacific Company	OS				
3	CE2 Environmental	OS				
4	Conectiv Energy Supply	OS				
5	Central Illinois Public Service Co.	OS				
6	CMS Energy Management	OS				
7	Constellation Energy Commodities	OS				
8	City Water Light & Power	OS				
9	Dynegy Power Marketing	OS				
10	DTE Energy	OS				
11	Element Markets	OS				
12	Exelon Generation	OS				
13	First Energy Solutions	OS				
14	Fortis Energy Marketing	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Florida Power & Light	OS				
2	Grey K Renewable Energy	OS				
3	Ameren Energy Marketing (Affiliate)	OS				
4	Great River Energy	OS				
5	Invenergy Renewable	OS				
6	Integrys Energy Services	OS				
7	Illinois Power Company (Affiliate)	OS				
8	JP Morgan Ventures Energy Corp	OS				
9	Minnesota Power	OS				
10	Midwest Independent System Operator	OS				
11	Minnesota Municipal Power Agency	OS				
12	Merrill Lynch Commodities	OS				
13	Nexera Energy Power	OS				
14	Nexant	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Peru, Illinois	OS				
2	Reliant Energy Services	OS				
3	Sterling Plant	OS				
4	Union Electric Company (Affiliate)	OS				
5	Wisconsin Electric Power	OS				
6	Wisconsin Public Service	OS				
7	WM Renewable Energy	OS				
8	Voluntary Curtailment Credit	OS				
9	Sempra Energy Trading	OS				
10	Dave Driscoll	OS				
11	John Albers	OS				
12	Metamora High School	OS				
13	Resource Technology Services	OS				
14	Tazewell Company Landfill Gas Plant	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Output Adjustment					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				289,174		289,174	1
				35,326		35,326	2
				61,047		61,047	3
				75,719		75,719	4
			-398,333	-2,552,236		-2,950,569	5
			272,479			272,479	6
581,915				38,447,381		38,447,381	7
				54,912		54,912	8
42,881			1,762,999	4,326,404	52,661	6,142,064	9
79,119			450	5,209,411		5,209,861	10
				7,066		7,066	11
				1,487,803		1,487,803	12
			10,710	260,313		271,023	13
			318,240			318,240	14
3,012,697			4,473,595	164,628,305	20,995	169,122,895	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				100,853		100,853	1
				5,062		5,062	2
556,396			689,042	64,367,314	15,626	65,071,982	3
			1,767			1,767	4
				7,789		7,789	5
				28,341		28,341	6
			-44,750	74,379		29,629	7
75,041			105,400	4,924,396		5,029,796	8
			115,655			115,655	9
1,615,657				44,350,437	-80,730	44,269,707	10
			1,857			1,857	11
				146,447		146,447	12
				7,688		7,688	13
				68,797		68,797	14
3,012,697			4,473,595	164,628,305	20,995	169,122,895	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
				68,217		68,217	1
			760,495			760,495	2
				561,846		561,846	3
			444,064		31,038	475,102	4
			20,443			20,443	5
			314,753		2,128	316,881	6
				29,750		29,750	7
					272	272	8
			98,324			98,324	9
				12		12	10
				20		20	11
1				39		39	12
513				30,145		30,145	13
17,673				968,607		968,607	14
3,012,697			4,473,595	164,628,305	20,995	169,122,895	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
43,501				1,185,846		1,185,846	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
3,012,697			4,473,595	164,628,305	20,995	169,122,895	

Schedule Page: 326 Line No.: 5 Column: a

(Affiliate)

Schedule Page: 326 Line No.: 9 Column: l

Amount represents Illinois Auction Ancillary Charges.

Schedule Page: 326.1 Line No.: 3 Column: l

Amount represents Illinois Auction Ancillary Charges.

Schedule Page: 326.1 Line No.: 10 Column: l

Detail of the Other Charges are as follows:

MISO Activities	$	56,479
Inadvertent Energy		6,736
Energy Losses		(345,681)
Revenue Neutrality Uplift		144,627
Revenue Sufficiency Guarantees		436,849
Auction Revenue Rights		(588,841)
Ancillary Regulation		129,743
Ancillary Spinning		84,990
Ancillary Supplemental		7,697
Financial Transmission Rights		(13,329)
Total	$	(80,730)

Schedule Page: 326.2 Line No.: 4 Column: l

Amount represents Illinois Auction Ancillary Charges.

Schedule Page: 326.2 Line No.: 6 Column: l

Amount represents Illinois Auction Ancillary Charges.

Schedule Page: 326.2 Line No.: 8 Column: l

Fulfilling the delivery, implementation and monitoring of new sales.

Schedule Page: 326.3 Line No.: 1 Column: m

This note applies to the total of column M.

Total Purchased Power (Account 555) per this page (327, total column M) will not agree to Purchased Power on page 321 (line 76B) as the purchased power per this page does not include the MISO RSG Resettlement Accrual recorded as of 12/31/09.

Purchased Power page 327, total column M	$	169,122,895
MISO RSG Resettlement Accrual		331,043
Purchased Power page 321, line 76B	$	169,453,938

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Midwest Independent System Operator	Various	Various	LFP
2	Sempra Energy Trading	Various	Various	FNO
3	Ameren Energy Marketing (Affiliate)	Various	Various	FNO
4	American Powernet	Various	Various	FNO
5	Bluestar Energy Services	Various	Various	FNO
6	Linde Energy Services	Various	Various	FNO
7	Clay Electric	Various	Various	FNO
8	Constellation New Energy	Various	Various	FNO
9	Conoco	Various	Various	FNO
10	Cornbelt	Various	Various	FNO
11	Edgar Electric Cooperative	Various	Various	FNO
12	Exelon Generation Company	Various	Various	FNO
13	Exolon Energy	Various	Various	FNO
14	City of Fairfield	Various	Various	FNO
15	First Energy	Various	Various	FNO
16	Glacial Energy	Various	Various	FNO
17	Illinois Municipal Electric Associated	Various	Various	FNO
18	Liberty Power	Various	Various	FNO
19	MidAmerican Energy Company	Various	Various	FNO
20	Missouri Joint Municipal Electric Utility	Various	Various	FNO
21	City of Mount Carmel	Various	Various	FNO
22	City of Newton	Various	Various	FNO
23	Norris Electric	Various	Various	FNO
24	Prairieland Services	Various	Various	FNO
25	Village of Riverton	Various	Various	FNO
26	Southern Illinois Power Cooperative	Various	Various	FNO
27	Soyland	Various	Various	FNO
28	Strategic Energy	Various	Various	FNO
29	Suez Energy Marketing	Various	Various	FNO
30	City of Sullivan	Various	Various	FNO
31	Southwestern Electric Cooperative	Various	Various	FNO
32	Western Power Services	Various	Various	FNO
33	Wabash Valley Power	Various	Various	FNO
34	Wayne White Counties Electric Cooperative	Various	Various	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Auction Supplier System	Various	Various	FNO
2	Ameren Services (Affiliate)	Various	Various	FNO
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
	Various	Various		4,874,482	4,874,482	1
	Various	Various		231,553	231,553	2
	Various	Various		819,269	819,269	3
	Various	Various		9,618	9,618	4
	Various	Various		96,351	96,351	5
	Various	Various		21,292	21,292	6
	Various	Various		7,472	7,472	7
	Various	Various		306,939	306,939	8
	Various	Various		145,584	145,584	9
	Various	Various		3,723	3,723	10
	Various	Various		12,791	12,791	11
	Various	Various		38,269	38,269	12
	Various	Various		36,332	36,332	13
	Various	Various		10,114	10,114	14
	Various	Various		104,415	104,415	15
	Various	Various		10,055	10,055	16
	Various	Various		221,596	221,596	17
	Various	Various		7,602	7,602	18
	Various	Various		285,347	285,347	19
	Various	Various		5,949	5,949	20
	Various	Various		14,949	14,949	21
	Various	Various		4,229	4,229	22
	Various	Various		50,644	50,644	23
	Various	Various		36,574	36,574	24
	Various	Various		2,739	2,739	25
	Various	Various		80,799	80,799	26
	Various	Various		344,306	344,306	27
	Various	Various		80,566	80,566	28
	Various	Various		18,043	18,043	29
	Various	Various		9,064	9,064	30
	Various	Various		57,720	57,720	31
	Various	Various		252,581	252,581	32
	Various	Various		99,635	99,635	33
	Various	Various		44,412	44,412	34
			0	**8,345,014**	**8,345,014**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
	Various	Various				1
	Various	Various				2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**8,345,014**	**8,345,014**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,103,605	515,310	1,618,915	1
	236,152		236,152	2
	845,004		845,004	3
	8,722		8,722	4
	88,697		88,697	5
	19,018		19,018	6
	9,256		9,256	7
	332,701		332,701	8
	144,371		144,371	9
	4,640	70,665	75,305	10
	16,551		16,551	11
	52,997		52,997	12
	30,021		30,021	13
	13,762		13,762	14
	150,512		150,512	15
	13,013		13,013	16
	295,802		295,802	17
	12,287		12,287	18
	341,078		341,078	19
	8,081		8,081	20
	19,836		19,836	21
	6,077		6,077	22
	64,509		64,509	23
	56,027		56,027	24
	4,474	92,817	97,291	25
	90,853		90,853	26
	260,305		260,305	27
	111,837		111,837	28
	33,317		33,317	29
	12,420		12,420	30
	81,353		81,353	31
	278,869		278,869	32
	121,434		121,434	33
	50,940		50,940	34
0	**6,055,715**	**1,261,066**	**7,316,781**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		522,707	522,707	1
	1,137,194	59,567	1,196,761	2
				3
				4
				5
				6
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				9
				10
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				26
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				28
				29
				30
				31
				32
				33
				34
0	**6,055,715**	**1,261,066**	**7,316,781**	

Schedule Page: 328 Line No.: 1 Column: a

Central Illinois Light Co. (CILCO) is a transmission owning member of the MISO RTO. CILCO is not a transmission provider. CILCO does not sell transmission services or ancillary services directly. Instead, CILCO receives revenues from transmission services and ancillary services sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

Schedule Page: 328 Line No.: 1 Column: d

LFP - All contracts are maintained by the Midwest Independent System Operator (MISO).

Schedule Page: 328 Line No.: 1 Column: m

The other charges listed in this column include:

$	411,638	Schedule 1 (Scheduling System Control & Dispatch)
	23,139	Schedule 24 (Control Area Operator Cost Recovery)
	30,203	MISO
	71,424	Transmission Service Losses
	(21,093)	Reactive Supply and Voltage Control
$	515,311	

Schedule Page: 328 Line No.: 10 Column: m

The other charges listed in this column include:

$ 70,665 Facility Use

Schedule Page: 328 Line No.: 25 Column: m

The other charges listed in this column include:

$ 92,817 Facility Use

Schedule Page: 328.1 Line No.: 1 Column: m

The other charges listed in this column include:

$ 522,707 Ancillary Services

Schedule Page: 328.1 Line No.: 2 Column: m

The other charges listed in this column include:

$	27,583	Regulation & Frequency Reserve Service
	18,625	Spinning Reserve Service
	2,010	Supplemental Reserve Service
	11,349	Transmission Service Losses
$	59,567	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Midwest Indep Sys Oper	OS	3,846,115	3,846,115		152,106	923,067	1,075,173
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		3,846,115	3,846,115		152,106	923,067	1,075,173

Schedule Page: 332 Line No.: 1 Column: a

Central Illinois Light Company (CILCO) is a transmission owning member of the Midwest Independent System Operator (MISO) RTO. CILCO is not a transmission provider. CILCO does not purchase transmission services directly. Instead, CILCO incurs charges from MISO for the purchase of transmission services from other participants in the MISO grid. MISO calculates the expenses that are incurred and collects the outstanding charges from each of the market participants. Then MISO distributes the expenses to the proper market participants within the MISO transmission grid.

Schedule Page: 332 Line No.: 1 Column: g

These other charges are related to:

$	785,810	Schedule 2 (Reactive Supply & Voltage Control)
	156,810	Illinois Auction Ancillary Charges
	(19,553)	Adjustment to expected SECA settlement amounts
$	923,067	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	213,546
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	141,898
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	121,250
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Public Relations Expenses:	
7	Items less than $5,000	67,156
8		
9	Other Miscellaneous General Expenses:	
10	Moody's Investors Service	31,000
11	Standard & Poor	60,000
12	Fitch, Inc.	5,257
13	Items less than $5,000	59,861
14		
15	Trade Association, Public Service Organization and	
16	Chamber of Commerce Dues	
17	Items less than $5,000	1,255
18		
19	Apportioned to Gas Departments	-237,169
20		
21	Labor allocations from Service Company	70,589
22		
23		
24		
25		
26		
27		
28		
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45		
46	TOTAL	534,643

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			5,331		5,331
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	1,833,742				1,833,742
8	Distribution Plant	21,108,763				21,108,763
9	Regional Transmission and Market Operation					
10	General Plant	948,744				948,744
11	Common Plant-Electric					
12	TOTAL	23,891,249		5,331		23,896,580

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Midwest Independent Transmission System	188,730		188,730	
2	Operator-FERC Cost Recovery Adder				
3					
4	Public Utility Fund Base Maintenance	273,353		273,353	
5	Contribution-IL Department of Revenue				
6					
7	Annual pro rata share for the Energy	92,671		92,671	
8	Efficiency Program				
9					
10	Professional services in connection with		686,347	686,347	
11	regulatory matters				
12					
13	National Regulatory Research Institute	4,718		4,718	
14					
15	Professional services in connection with		159,866	159,866	
16	regulatory matters				
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	559,472	846,213	1,405,685	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Electric	928	188,730					1
							2
							3
Electric	928	273,353					4
							5
							6
Electric	928	92,671					7
							8
							9
Electric	928	686,347					10
							11
							12
Electric	928	4,718					13
							14
Gas	928	159,866					15
							16
							17
							18
							19
							20
							21
							22
							23
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		1,405,685					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B.(1)	Electric Power Research Institute
2	A.(6)	General R&D Expenses
3	B.(4)	Minor Items (5)
4		
5	Totals	
6		
7		
8		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	103,184	Various	103,184		1
13,854		930	13,854		2
	13,283	Various	13,283		3
					4
13,854	116,467		130,321		5
					6
					7
					8
					9
					10
					11
					12
					13
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production			
4	Transmission	511,953		
5	Regional Market			
6	Distribution	6,573,134		
7	Customer Accounts	3,204,977		
8	Customer Service and Informational	340,015		
9	Sales	2,798		
10	Administrative and General	54,033,792		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	64,666,669		
12	Maintenance			
13	Production			
14	Transmission	261,213		
15	Regional Market			
16	Distribution	5,840,197		
17	Administrative and General	128,464		
18	TOTAL Maintenance (Total of lines 13 thru 17)	6,229,874		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)			
21	Transmission (Enter Total of lines 4 and 14)	773,166		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	12,413,331		
24	Customer Accounts (Transcribe from line 7)	3,204,977		
25	Customer Service and Informational (Transcribe from line 8)	340,015		
26	Sales (Transcribe from line 9)	2,798		
27	Administrative and General (Enter Total of lines 10 and 17)	54,162,256		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	70,896,543	1,395,093	72,291,636
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	501,236		
34	Storage, LNG Terminaling and Processing	490,637		
35	Transmission	248,614		
36	Distribution	4,164,844		
37	Customer Accounts	2,088,073		
38	Customer Service and Informational	178,292		
39	Sales	390		
40	Administrative and General	2,395,799		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	10,067,885		
42	Maintenance			
43	Production-Manufactured Gas	155,409		
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	100,320		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,533,783		
49	Administrative and General	77,576		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,867,088		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	155,409		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	501,236		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	490,637		
56	Transmission (Lines 35 and 47)	348,934		
57	Distribution (Lines 36 and 48)	7,698,627		
58	Customer Accounts (Line 37)	2,088,073		
59	Customer Service and Informational (Line 38)	178,292		
60	Sales (Line 39)	390		
61	Administrative and General (Lines 40 and 49)	2,473,375		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	13,934,973	220,773	14,155,746
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	84,831,516	1,615,866	86,447,382
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	10,053,332	518,381	10,571,713
69	Gas Plant	6,311,556	325,444	6,637,000
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	16,364,888	843,825	17,208,713
72	Plant Removal (By Utility Departments)			
73	Electric Plant	545,613	5,845	551,458
74	Gas Plant	52,703	565	53,268
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	598,316	6,410	604,726
77	Other Accounts (Specify, provide details in footnote):			
78	Other Work in Progress	37,315	585	37,900
79	Other Income & Deductions	157,223		157,223
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93				
94				
95	TOTAL Other Accounts	194,538	585	195,123
96	TOTAL SALARIES AND WAGES	101,989,258	2,466,686	104,455,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	7,853,050	18,116,432	30,406,614	44,385,938
3	Net Sales (Account 447)	(10,009)	(10,148)	(11,467)	(11,638)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Inadvertent Distribution (Account 447)	(5,289)	(23,700)	(4,214)	(5,044)
8	Inadvertent Distribution (Account 555)	952	3,299	4,731	6,736
9	Revenue Sufficiency Guarantee a/c 555)	215,187	736,200	830,153	954,461
10	Losses (Account 555)	(51,723)	(121,094)	(221,007)	(345,681)
11	Revenue Neutrality Uplift (Account 555)	(91,176)	(136,814)	(163,130)	(77,440)
12	MISO Admin charges (Account 555)	3,534	7,959	49,832	56,478
13	Auction Revenue Rights (Acct 555)	(103,349)	(239,401)	(447,997)	(588,841)
14	Financial Transmission Rights (Acct 555)		7	(2,177)	(13,329)
15	Ancillary Regulation (Account 555)	31,556	59,689	90,131	129,743
16	Ancillary Spinning (Account 555)	19,834	38,702	57,569	84,990
17	Ancillary Supplemental (Account 555)	1,027	2,585	5,002	7,697
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46	TOTAL	7,863,594	18,433,716	30,594,040	44,584,070

Schedule Page: 397 Line No.: 9 Column: b

$ 49,599 Related to the RSG resettlement accrual has been excluded from first quarter because it is an accrual and thus not shown on the Midwest ISO settlement statements.

Schedule Page: 397 Line No.: 9 Column: c

$ (49,599) Related to the reversal of the RSG resettlement accrual has been excluded from second quarter for consistency with first quarter treatment.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						411,638
2	Reactive Supply and Voltage			785,810			-21,093
3	Regulation and Frequency Response			129,743			27,583
4	Energy Imbalance						
5	Operating Reserve - Spinning			84,990			18,625
6	Operating Reserve - Supplement			7,697			2,010
7	Other			258,264			522,707
8	Total (Lines 1 thru 7)			1,266,504			961,470

Schedule Page: 398   Line No.: 1   Column: b

Central Illinois Light Company (CILCO) is a transmission owning member of the MISO RTO. CILCO is not a transmission provider. CILCO does not sell transmission services or ancillary services directly. Instead, CILCO receives revenues from transmission services and ancillary sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

Schedule Page: 398   Line No.: 7   Column: d

Amount represents reimbursements of ancillary services costs to the host utility on behalf of the Illinois Auction supplier.

Schedule Page: 398   Line No.: 7   Column: g

Amount represents reimbursements of ancillary services costs to the host utility on behalf of the Illinois Auction supplier.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Central Illinois Lighting Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	985	15	19	443	327	32		84	99
2	February	902	3	19	341	353	32		78	98
3	March	822	3	19	259	371	21		34	137
4	Total for Quarter 1	2,709			1,043	1,051	85		196	334
5	April	735	6	11	287	332	21		83	12
6	May	803	27	16	359	360	21		51	12
7	June	1,172	23	17	647	386	24		47	68
8	Total for Quarter 2	2,710			1,293	1,078	66		181	92
9	July	970	28	15	480	405	31		47	6
10	August	1,051	9	18	586	365	35		49	16
11	September	856	10	16	236	444	31		111	35
12	Total for Quarter 3	2,877			1,302	1,214	97		207	57
13	October	747	27	19	226	362	34		100	24
14	November	844	30	19	337	378	34		71	25
15	December	966	9	18	405	390	36		105	30
16	Total for Quarter 4	2,557			968	1,130	104		276	79
17	Total Year to Date/Year	10,853			4,606	4,473	352		860	562

Schedule Page: 400 Line No.: 1 Column: b

Since Ameren Illinois Utilities (AMIL) is not a Transmission Provider, but instead is a Transmission Owner in the Midwest Independent System Operator (MISO), this calculation is performed by including the PTDF (percent transfer distribution factor) of the paths of MISO reservations multiplied by the magnitude of reservations to determine an impact on AMIL's portions of the MISO zonal transmission system. The information used in the calculation is received from MISO in the Monthly Revenue files.

The AMIL portion of the MISO zonal transmission system includes Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	2,985,370
3	Steam				
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
7	Other	17,201			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	17,201	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	3,012,697	27	Total Energy Losses	44,528
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,029,898
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	8,345,014			
17	Delivered	8,345,014			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,029,898			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Central Illinois Lighting Company

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	293,087		679	15	1800-1900
30	February	241,263		604	3	1800-1900
31	March	279,243		484	2	1800-1900
32	April	230,199		419	6	2000-2100
33	May	156,629		466	22	1700-1800
34	June	292,476		861	22	1800-1900
35	July	256,022		646	15	1700-1800
36	August	266,181		747	9	1700-1800
37	September	216,069		487	14	1900-2000
38	October	181,831		400	12	1900-2000
39	November	249,167		550	30	1700-1800
40	December	367,731		645	10	2000-2100
41	TOTAL	3,029,898				

Schedule Page: 401 Line No.: 22 Column: b

Excludes 2,755,932 MW delivered to delivery service customers (non-energy sales). See footnote on page 300, line 10, col D.

Schedule Page: 401 Line No.: 29 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 30 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 31 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 32 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 33 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 34 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 35 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 36 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 37 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 38 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 39 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Schedule Page: 401 Line No.: 40 Column: b

Disclosed megawatts are for Central Illinois Light Company energy customers only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)						
6	Net Peak Demand on Plant - MW (60 minutes)						
7	Plant Hours Connected to Load						
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees						
12	Net Generation, Exclusive of Plant Use - KWh						
13	Cost of Plant: Land and Land Rights						
14	Structures and Improvements						
15	Equipment Costs						
16	Asset Retirement Costs						
17	Total Cost						
18	Cost per KW of Installed Capacity (line 17/5) Including						
19	Production Expenses: Oper, Supv, & Engr						
20	Fuel						
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses						
23	Steam From Other Sources						
24	Steam Transferred (Cr)						
25	Electric Expenses						
26	Misc Steam (or Nuclear) Power Expenses						
27	Rents						
28	Allowances						
29	Maintenance Supervision and Engineering						
30	Maintenance of Structures						
31	Maintenance of Boiler (or reactor) Plant						
32	Maintenance of Electric Plant						
33	Maintenance of Misc Steam (or Nuclear) Plant						
34	Total Production Expenses						
35	Expenses per Net KWh						
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned						
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)						
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year						
41	Average Cost of Fuel per Unit Burned						
42	Average Cost of Fuel Burned per Million BTU						
43	Average Cost of Fuel Burned per KWh Net Gen						
44	Average BTU per KWh Net Generation						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
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0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Kickapoo	McGrath/Limit	138.00	138.00	1	3.12		1
2	R.S. Wallace	Spring Bay Sub	138.00	138.00	1,2,3,	11.74	0.01	1
3	E.D. Edwards	Cat Mapleton	138.00	138.00	1,3	5.79	0.30	1
4	Lincoln-Kickapoo	IP Co Tap	138.00	138.00	1	5.22		1
5	Fargo	Hines	138.00	138.00	1,3,4	9.33		1
6	R.S. Wallace	Tazewell	138.00	138.00	1,3	6.52	6.62	1
7	Tazewell	Eastern	138.00	138.00	1,3	15.20		1
8	Hines Sub	Cat #2 Sub	138.00	138.00	1,2,3	3.52	6.62	2
9	E.D. Edwards	Fargo	138.00	138.00	3		20.40	2
10	E.D. Edwards	Cat Mapleton Fargo	138.00	138.00	2,3	23.19		2
11	R.S. Wallace	Cat E. Peoria	138.00	138.00	3		0.73	2
12	E.D. Edwards	Tazewell	138.00	138.00	3		9.00	2
13	E.D. Edwards	Tazewell	138.00	138.00	3	9.07		2
14	E.D. Edwards	Cat E. Peoria	138.00	138.00	1,3	7.82	1.65	2
15	Cat #2 Sub	Tazewell	138.00	138.00	1,2,3		10.87	2
16	Fargo	Moss Cat	138.00	138.00	3	13.73		2
17	New Holland	Kickapoo	138.00	138.00	1	12.00		1
18	Tazewell/Lincoln	E. Springfield	138.00	138.00	1,2,3	58.00		1
19	E.D. Edwards	CE Co Tap	138.00	138.00	1,3	1.21	0.30	2
20	Moss Cat	Hallock	138.00	138.00	1,3	6.89	2.20	2
21	R.S. Wallace	Keystone	138.00	138.00	3	5.23		2
22	E.D. Edwards	Keystone	138.00	138.00	1	3.27		1
23	E. Springfield	Elkhart	138.00	138.00	2	14.63		1
24	Hallock	Richland	138.00	138.00	3	9.97		1
25	Spring Bay Sub	IP Structure "82"	138.00	138.00	2,3	0.22		1
26	Tazewell	Tower "5"	345.00	345.00	3		0.64	1
27	Tazewell	Tower "5"	345.00	345.00	3	0.64		1
28	Duck Creek	Tazewell	345.00	345.00	1,3,4	34.58		2
29	Duck Creek	Ipava	345.00	345.00	2	11.74		1
30	Henry River Crossing		69.00	138.00	3	1.52		2
31	Toledo Ave			138.00				
32	Lanesville Tap		138.00	138.00	1	0.14		1
33	Lanesville Tap		345.00	345.00	1	0.13		1
34	Limit Sub	Casimir Sub	34.50	138.00	1	4.27		1
35	Lincoln	Heyworth	34.50	138.00	1	10.77		1
36					TOTAL	289.46	63.93	50

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	E.D. Edwards	Bartonville		138.00	1,3		4.59	2
2	Footnote for Column (f)							
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31								
32								
33								
34								
35								
36					TOTAL	289.46	63.93	50

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
VARIOUS	46,118	55,059	101,177					1
636 ASCR	233,013	1,318,967	1,551,980					2
927.2 ACAR		408,494	408,494					3
477 ACSR	3,119	385,498	388,617					4
927.2 ACAR	86,432	2,271,273	2,357,705	-2,739	819,399	158,394	975,054	5
VARIOUS		903,877	903,877	-17,095	5,114,876	988,732	6,086,513	6
927.2 ACAR		224,721	224,721					7
VARIOUS				-20,340	6,085,660	1,176,390	7,241,710	8
927.2 ACAR	81,486	1,696,147	1,777,633					9
927.2 ACAR								10
927.2 ACAR		1,176,534	1,176,534	12,103	-3,620,734	-699,907	-4,308,538	11
954 ACSR	142,197	536,239	678,436	12,101	-3,620,735	-699,906	-4,308,540	12
VARIOUS				12,101	-3,620,734	-699,907	-4,308,540	13
VARIOUS		17,713	17,713	-394	117,744	22,760	140,110	14
VARIOUS	251,727	1,983,684	2,235,411					15
927.2 ACAR	168,357	2,721,658	2,890,015	-660	197,521	38,182	235,043	16
336.4 MCM	31,094	206,072	237,166					17
VARIOUS	171,451	16,425,795	16,597,246					18
VARIOUS	17,488	146,869	164,357	12,101	-3,620,735	-699,907	-4,308,541	19
927.2 ACAR	90,080	889,213	979,293					20
927.2 ACAR		1,148,504	1,148,504					21
2-927.2 ACAR	15,761	568,400	584,161					22
477 ACSR	55,166	627,013	682,179					23
VARIOUS	482,234	30,286	512,520					24
636 ACSR	94,067	2,194,630	2,288,697	-11,457	3,428,020	662,654	4,079,217	25
1277 ACAR	76,573	701,848	778,421					26
1277 ACAR								27
954 ACSR	1,859,162	12,143,858	14,003,020					28
954 ACSR	270,420	2,362,675	2,633,095					29
1277 ACAR		268,930	268,930					30
	98,390		98,390					31
1272 ACAR		323,487	323,487					32
1277 ACAR								33
2-266 ACSR								34
2-266.8 ACSR								35
	4,274,335	51,737,444	56,011,779	-4,279	1,280,282	247,485	1,523,488	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
927.2 ACAR								1
								2
								3
								4
								5
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	4,274,335	51,737,444	56,011,779	-4,279	1,280,282	247,485	1,523,488	36

Schedule Page: 422.1 Line No.: 2 Column: a

Footnote for total amount in Column (f)

There were no new additions in the lenth of miles in column (f) when compared to last year. Corrections have been made to accurately reflect the total amount of miles.

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
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43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Cincinnati - S/Pekin	Unattended Trans.	69.00	69.00	
2	Duck Creek - E/Canton	Attended Trans.	345.00	23.00	
3	Duck Creek - E/Canton	Attended Trans.	345.00	6.90	
4	Eastern - Washington	Unattended Trans.	138.00	69.00	
5	Elba - W/Brimfield	Unattended Trans.	69.00	69.00	
6	E.D. Edwards - S/Bartonville	Attended Trans.	69.00	16.00	
7	E.D. Edwards - S/Bartonville	Attended Trans.	69.00	19.40	
8	E.D. Edwards - S/Bartonville	Attended Trans.	69.00	4.16	
9	E.D. Edwards - S/Bartonville	Attended Trans.	138.00	21.40	
10	Fargo - W/Peoria	Unattended Trans.	138.00	69.00	
11	Hallock - W/Chillicothe	Unattended Trans.	138.00	69.00	
12	Hawthorne - W/Washington	Unattended Trans.	69.00	69.00	
13	Hines - Peoria Heights	Unattended Trans.	138.00	69.00	
14	Marshall - N/Henry	Unattended Trans.	69.00	69.00	
15	Monica - W/Princeville	Unattended Trans.	69.00	69.00	
16	R.S. Wallace - East Peoria	Unattended Trans.	138.00	69.00	
17	Tazewell - Groveland	Unattended Trans.	345.00	138.00	
18	Tazewell - Groveland	Unattended Trans.	138.00	69.00	
19	East Springfield - Springfield	Unattended Trans.	138.00	34.50	
20	Kickapoo - Lincoln	Unattended Trans.	138.00	34.50	
21	Lanesville - E/Springfield	Unattended Trans.	345.00	138.00	
22	Muncie - Muncie	Unattended Trans.	69.00	69.00	
23	Glover - N/St. Joseph	Unattended Trans.	69.00	69.00	
24	Adams - Peoria	Unattended Distr.	69.00	13.20	
25	Allen - Peoria	Unattended Distr.	69.00	13.20	
26	Allta - Dunlap	Unattended Distr.	138.00	13.80	
27	Bartonville - Bartonville	Unattended Distr.	69.00	13.20	
28	Beverly Manor - Washington	Unattended Distr.	69.00	13.20	
29	Bradley - Peoria	Unattended Distr.	69.00	13.20	
30	Bush - Morton	Unattended Distr.	69.00	12.50	
31	Chester - Peoria	Unattended Distr.	69.00	13.20	
32	Corrington - Peoria	Unattended Distr.	69.00	13.20	
33	Court - Pekin	Unattended Distr.	69.00	13.20	
34	Cruger - W/Eureka	Unattended Distr.	69.00	13.20	
35	East Peoria - East Peoria	Unattended Distr.	138.00	13.20	
36	Elm Grove - Pekin	Unattended Distr.	69.00	13.20	
37	Eureka - Eureka	Unattended Distr.	69.00	13.20	
38	Farmdale - East Peoria	Unattended Distr.	69.00	13.20	
39	Fisher - Peoria	Unattended Distr.	69.00	13.20	
40	Flint - Morton	Unattended Distr.	138.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Fondulac - East Peoria	Unattended Distr.	69.00	13.20	
2	Fulton - Lacon	Unattended Distr.	69.00	13.80	
3	Glendale - Peoria	Unattended Distr.	69.00	13.20	
4	Grandview - Peoria	Unattended Distr.	69.00	13.20	
5	Groveland - East Peoria	Unattended Distr.	69.00	13.20	
6	Hallock - W/Chillicothe	Unattended Distr.	69.00	13.20	
7	Harmon - Peoria	Unattended Distr.	69.00	13.20	
8	Hauk - Peoria	Unattended Distr.	69.00	13.20	
9	Henry - Henry	Unattended Distr.	138.00	12.50	
10	Hines - Peoria Heights	Unattended Distr.	69.00	13.20	
11	Jefferson - Washington	Unattended Distr.	69.00	13.20	
12	Junction - Peoria	Unattended Distr.	69.00	13.20	
13	Kice - W/Washington	Unattended Distr.	69.00	13.20	
14	Koch - Pekin	Unattended Distr.	69.00	13.20	
15	Lake - Peoria	Unattended Distr.	69.00	13.20	
16	Linberg - W/Farmington	Unattended Distr.	69.00	13.20	
17	Logan - W/Bellevue	Unattended Distr.	69.00	13.20	
18	Metamora - Metamora	Unattended Distr.	69.00	13.20	
19	Meyer - Peoria	Unattended Distr.	69.00	13.20	
20	Nebraska - Peoria	Unattended Distr.	69.00	13.20	
21	New York - Peoria	Unattended Distr.	69.00	13.20	
22	Northmoor - Peoria	Unattended Distr.	69.00	13.80	
23	Northwest - Peoria	Unattended Distr.	69.00	13.20	
24	Osage - Pekin	Unattended Distr.	69.00	13.20	
25	Ozark - Bartonville	Unattended Distr.	69.00	13.20	
26	Park - Pekin	Unattended Distr.	69.00	13.20	
27	Pioneer - Peoria	Unattended Distr.	138.00	13.20	
28	Radnor - Peoria	Unattended Distr.	138.00	13.20	
29	Sheridan - Pekin	Unattended Distr.	69.00	13.20	
30	Southwood - Morton	Unattended Distr.	69.00	13.20	
31	Spring Bay - Spring Bay	Unattended Distr.	138.00	13.20	
32	Tremont - Tremont	Unattended Distr.	69.00	12.50	
33	University - Peoria	Unattended Distr.	69.00	13.20	
34	Wheeler - Mapleton	Unattended Distr.	69.00	13.20	
35	Atlanta - Atlanta	Unattended Distr.	34.50	12.50	
36	Bement - Bement	Unattended Distr.	34.50	12.50	
37	Bissell - Springfield	Unattended Distr.	34.50	12.50	
38	Fairmount - W/Fairmount	Unattended Distr.	69.00	12.50	
39	Hammond - Hammond	Unattended Distr.	34.50	13.20	
40	Kickapoo - Lincoln	Unattended Distr.	138.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Limit - SE/Lincoln	Unattended Distr.	138.00	12.50	
2	Mansfield - Springfield	Unattended Distr.	34.50	12.50	
3	McGrath - N/Lincoln	Unattended Distr.	138.00	12.50	
4	Mt. Pulaski - Lincoln	Unattended Distr.	34.50	12.50	
5	Ridge - Springfield	Unattended Distr.	34.50	12.50	
6	Riverton - Riverton	Unattended Distr.	34.50	12.50	
7	Rochester - N. Rochester	Unattended Distr	34.50	12.50	
8	St. Joseph - St. Joseph	Unattended Distr	69.00	12.50	
9	Sand Prairie - Green Valley	Unattended Distr	69.00	13.20	
10	Heyworth - Heyworth	Unattended Distr	34.50	12.50	
11	North Morton - Morton	Unattended Distr	69.00	12.50	
12	Sidney - Sidney	Unattended Distr	69.00	12.50	
13	San Jose Railsplitter - San Jose	Unattended Distr.	138.00	138.00	
14	Substations less than 10,000 MVA-				
15	38 Substations	Unattended Distri			
16	1 Substation	Unattended Trans			
17					
18	Summary:				
19	2 Substations (10 MVA & over)	Attended Trans			
20	17Substations (10 MVA & over)	Unattended Trans			
21	69 substations (10 MVA & over)	Unattended Distr			
22	38 Substations (Under 10 MVA)	Unattended Distr			
23	1 Substation (Under 10 MVA)	Unattended Trans			
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
460	1					2
80	1					3
100	1					4
						5
145	1					6
300	1					7
54	2					8
385	1					9
100	1					10
100	1					11
						12
200	2					13
						14
						15
300	2					16
1000	2					17
150	1					18
180	3					19
78	3					20
308	1					21
						22
						23
25	1					24
25	2					25
45	1					26
37	2					27
20	1					28
20	1					29
42	2					30
20	1					31
13	1					32
20	1					33
13	1					34
50	2					35
25	2					36
13	1					37
20	1					38
75	3					39
44	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
22	1					2
50	2					3
45	2					4
25	2					5
20	1					6
25	1					7
25	1					8
13	1					9
25	1					10
20	1					11
19	2					12
27	2					13
20	1					14
22	1					15
13	1					16
13	1					17
14	1					18
20	1					19
25	2					20
22	1					21
22	1					22
40	2					23
20	1					24
20	1					25
20	1					26
50	2					27
80	2					28
25	1					29
25	1					30
10	1					31
13	1					32
20	1					33
20	1					34
11	1					35
13	1					36
13	1					37
28	2					38
13	1					39
28	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
25	2					2
22	1					3
11	1					4
13	1					5
13	1					6
13	1					7
13	1					8
22	1					9
13	1					10
13	2					11
13	1					12
						13
						14
235	40					15
9	1					16
						17
						18
1424	7					19
2516	17					20
1659	87					21
235	40					22
9	1					23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Purchase of assets	Ameren Services	391	394,596
3	Transaction support	Ameren Services	379,903,920	602,067
4	Corporate communications support	Ameren Services	909,920,921,930	234,333
5	Corporate planning support	Ameren Services	908,920,923	725,535
6	Financial, tax, and audit services	Ameren Services	379,920,923	3,166,504
7	Transmission support	Ameren Services	560,561,566,920,931	1,269,310
8	Engineering and construction support	Ameren Services	374,379,588,920	891,330
9	Environmental, safety and health services	Ameren Services	920,923,925	258,008
10	Executive services	Ameren Services	379,920,921	457,687
11	Legal services	Ameren Services	426,908,920,923,928	1,570,838
12	Human resources services	Ameren Services	379,920,921,923	1,754,415
13	Information technology services	Ameren Services	184,379,920,921,923	8,797,132
14	Rent expense	Ameren Services	931	1,118,540
15	Supply services	Ameren Services	701,705,920,935	766,741
16	Treasury services	Ameren Services	920,921,923,924,925	2,563,427
17	Business segment support services	Ameren Services	374,920	940,449
18	Rent expense	AmerenIP	931	2,532,536
19	Stores inventory transfers	AmerenIP	154	592,249
20	**Non-power Goods or Services Provided for Affiliate**			
21	Storm support	AmerenUE	921	645,657
22	Rental income	AmerenIP	454,493	266,375
23	Building services	AmerenIP	921	213,405
24	Customer service support	AmerenIP	921	8,784,005
25	Gas storage	AmerenIP	921	852,641
26	Gas technical services	AmerenIP	921	4,157,978
27	Engineering & construction services	AmerenIP	921	12,206,345
28	Government regulation services	AmerenIP	921	1,181,614
29	Corporate communications	AmerenIP	921	2,420,767
30	Motor transportation	AmerenIP	921	865,736
31	Meter services	AmerenIP	921	1,539,136
32	Dispatch services	AmerenIP	921	1,130,711
33	Information services	AmerenIP	921	637,693
34	Executive services	AmerenIP	921	2,306,420
35	Illinois utility operating services	AmerenIP	921	4,473,950
36	Real estate services	AmerenIP	921	1,351,359
37	Regulatory services	AmerenIP	921	902,768
38	Storm support	AmerenIP	921	220,722
39	Customer rate relief reimbursement	Genco	456,421	1,880,053
40	Customer rate relief reimbursement	Genco	456,421	850,966
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Purchase of assets	AmerenIP	368,370,381,392,396	1,861,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Central Illinois Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/19/2010	End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Call center support	AmerenIP	903	980,884
4	Storm support	AmerenIP	364,365,593	333,542
5	Engineering and construction support	AmerenIP	365,369,583,593	1,574,527
6	Gas procurement services	AFS	731,807,880,920	1,668,700
7	Rent expense	AmerenCIPS	931	839,360
8	Purchase of assets	AmerenCIPS	368,370,392,396	1,874,828
9	Stores inventory transfers	AmerenUE	154	324,599
10	Purchase of assets	AmerenUE	368,370,392,396	266,395
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Building services	AmerenCIPS	921	211,818
22	Customer service support	AmerenCIPS	921	4,915,644
23	Gas storage	AmerenCIPS	921	428,990
24	Gas technical services	AmerenCIPS	921	1,724,205
25	Engineering & construction services	AmerenCIPS	921	7,891,697
26	Government regulation services	AmerenCIPS	921	674,139
27	Corporate communications	AmerenCIPS	921	1,377,565
28	Motor transportation	AmerenCIPS	921	740,365
29	Meter services	AmerenCIPS	921	1,099,001
30	Dispatch services	AmerenCIPS	921	702,165
31	Information services	AmerenCIPS	921	339,038
32	Executive services	AmerenCIPS	921	2,614,419
33	Illinois utility operating services	AmerenCIPS	921	2,851,726
34	Real estate services	AmerenCIPS	921	845,149
35	Regulatory services	AmerenCIPS	921	859,156
36	Storm support	AmerenCIPS	921	4,609,601
37	Sale of assets	AmerenCIPS	368,370,392,381,396	1,278,980
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column:

Goods and services provided by Ameren Services Company are allocated via one of the following allocation methodologies:

Composite – Energy Sales, Customers and Employees
Based on equal weighting of energy sales, average customers and number of employees.

Customers
Based on a year-end count of electric and gas customers.

Sales
Based on the year-end energy sales.

Employees
Based on the number of full-time employees monthly.

Total capitalization
Based on total operating company capitalization value at year-end.

Total Assets
Based on total operating company assets at year-end.

Peak Load
Based on peak load at each operating center. Each operating power plant peak generation provides electric ratio. Gas ratio is derived from system peak at a transportation intake point for Ameren's system.

Generating Capacity
Based on nameplate generating capacity at each power plant.

Gas Throughput
Based on total gas usage including transportation customers at each Ameren operating gas system.

Current Tax Expense
Based on yearly tax expenses for each operating company.

Vehicle Ratio
Based on number of vehicles assigned to each operating company.

Accounting Transaction
Based on number of corporation transactions in a particular accounting system.

Information Technology (IT)
Based on number of IT-related activities.

Governmental Affairs
Based on the information by Ameren's Governmental Affairs organizations as to what companies and/or business segments will be supported in the coming year. The ratio will be determined annually, and/or at such times as may be required due to a significant change in circumstances.

Gross Plant-in-service plus Construction Work In Progress (CWIP)
Based on the Gross Plant-in-Service at the end of the most recent calendar year. The numerator of which is the total of Gross Plant-in-Service plus CWIP of an operating company or affiliate company, the denominator of which is for all operating companies or affiliates. This ratio will be determined annually, and/or at such time as may be required due to a significant

change in circumstances.

Electric Net Generation (Megawatt Hours)

Based on the electric net generation (megawatt hours) at the end of the most recent calendar year. The numerator of which is for an operating company. The denominator of which is for all operating companies. This ratio will be determined annually and/or at such time as may be required due to a significant change in circumstances.

Schedule Page: 429 Line No.: 39 Column:

Ameren Energy Generating Company

Schedule Page: 429 Line No.: 40 Column:

Ameren Energy Generating Company

Schedule Page: 429.1 Line No.: 6 Column:

Ameren Energy Fuels & Services

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