# Attached Section 285.310b: Most recent FERC Form 1.

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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

# 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 2008/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<br>Central Illinois Light Company | 02 Year/Period of Report<br>End of 2008/Q4 |
| 03 Previous Name and Date of Change *(if name changed during year)*<br>/ / | |
| 04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*<br>300 Liberty Street, Peoria, IL 61602 | |
| 05 Name of Contact Person<br>Marty J. Lyons, Jr. | 06 Title of Contact Person<br>Sr VP & Chief Acctg Officer |
| 07 Address of Contact Person *(Street, City, State, Zip Code)*<br>1901 Chouteau Avenue, St. Louis, MO 63103 | |

| | | |
|---|---|---|
| 08 Telephone of Contact Person,*Including Area Code*<br>(314) 554-2982 | 09 This Report Is<br>(1) [X] An Original (2) [ ] A Resubmission | 10 Date of Report *(Mo, Da, Yr)*<br>04/17/2009 |

**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<br>Marty J. Lyons, Jr. | 03 Signature | 04 Date Signed *(Mo, Da, Yr)* |
| 02 Title<br>Sr VP & Chief Accounting Officer | Marty J. Lyons, Jr. | 04/17/2009 |

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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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".


| Line No. | Title of Schedule (a) | Reference Page No. (b) | Remarks (c) |
|---|---|---|---|
| 1 | General Information | 101 | |
| 2 | Control Over Respondent | 102 | |
| 3 | Corporations Controlled by Respondent | 103 | |
| 4 | Officers | 104 | |
| 5 | Directors | 105 | |
| 6 | Important Changes During the Year | 108-109 | |
| 7 | Comparative Balance Sheet | 110-113 | |
| 8 | Statement of Income for the Year | 114-117 | |
| 9 | Statement of Retained Earnings for the Year | 118-119 | |
| 10 | Statement of Cash Flows | 120-121 | |
| 11 | Notes to Financial Statements | 122-123 | |
| 12 | Statement of Accum Comp Income, Comp Income, and Hedging Activities | 122(a)(b) | |
| 13 | Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep | 200-201 | |
| 14 | Nuclear Fuel Materials | 202-203 | None |
| 15 | Electric Plant in Service | 204-207 | |
| 16 | Electric Plant Leased to Others | 213 | None |
| 17 | Electric Plant Held for Future Use | 214 | |
| 18 | Construction Work in Progress-Electric | 216 | |
| 19 | Accumulated Provision for Depreciation of Electric Utility Plant | 219 | |
| 20 | Investment of Subsidiary Companies | 224-225 | |
| 21 | Materials and Supplies | 227 | |
| 22 | Allowances | 228-229 | None |
| 23 | Extraordinary Property Losses | 230 | None |
| 24 | Unrecovered Plant and Regulatory Study Costs | 230 | None |
| 25 | Transmission Service and Generation Interconnection Study Costs | 231 | None |
| 26 | Other Regulatory Assets | 232 | |
| 27 | Miscellaneous Deferred Debits | 233 | |
| 28 | Accumulated Deferred Income Taxes | 234 | |
| 29 | Capital Stock | 250-251 | |
| 30 | Other Paid-in Capital | 253 | |
| 31 | Capital Stock Expense | 254 | None |
| 32 | Long-Term Debt | 256-257 | |
| 33 | Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax | 261 | |
| 34 | Taxes Accrued, Prepaid and Charged During the Year | 262-263 | |
| 35 | Accumulated Deferred Investment Tax Credits | 266-267 | |
| 36 | Other Deferred Credits | 269 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | Accumulated Deferred Income Taxes-Accelerated Amortization Property | 272-273 | None |
| 38 | Accumulated Deferred Income Taxes-Other Property | 274-275 | |
| 39 | Accumulated Deferred Income Taxes-Other | 276-277 | |
| 40 | Other Regulatory Liabilities | 278 | |
| 41 | Electric Operating Revenues | 300-301 | |
| 42 | Sales of Electricity by Rate Schedules | 304 | |
| 43 | Sales for Resale | 310-311 | |
| 44 | Electric Operation and Maintenance Expenses | 320-323 | |
| 45 | Purchased Power | 326-327 | |
| 46 | Transmission of Electricity for Others | 328-330 | |
| 47 | Transmission of Electricity by ISO/RTOs | 331 | None |
| 48 | Transmission of Electricity by Others | 332 | |
| 49 | Miscellaneous General Expenses-Electric | 335 | |
| 50 | Depreciation and Amortization of Electric Plant | 336-337 | |
| 51 | Regulatory Commission Expenses | 350-351 | |
| 52 | Research, Development and Demonstration Activities | 352-353 | |
| 53 | Distribution of Salaries and Wages | 354-355 | |
| 54 | Common Utility Plant and Expenses | 356 | None |
| 55 | Amounts included in ISO/RTO Settlement Statements | 397 | |
| 56 | Purchase and Sale of Ancillary Services | 398 | |
| 57 | Monthly Transmission System Peak Load | 400 | |
| 58 | Monthly ISO/RTO Transmission System Peak Load | 400a | None |
| 59 | Electric Energy Account | 401 | |
| 60 | Monthly Peaks and Output | 401 | |
| 61 | Steam Electric Generating Plant Statistics | 402-403 | None |
| 62 | Hydroelectric Generating Plant Statistics | 406-407 | None |
| 63 | Pumped Storage Generating Plant Statistics | 408-409 | None |
| 64 | Generating Plant Statistics Pages | 410-411 | None |
| 65 | Transmission Line Statistics Pages | 422-423 | |
| 66 | Transmission Lines Added During the Year | 424-425 | None |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | Substations | 426-427 | |
| 68 | Footnote Data | 450 | |
| | Stockholders' Reports Check appropriate box:<br>[X] Four copies will be submitted<br>[ ] 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 Accounting 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.

**None**

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

**The Respondent, operating in the State of Illinois, furnishes electric and gas service.**

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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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, 2008, 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | most of Central Illinois | | |
| 3 | | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 375,000 |
| 2 | | | |
| 3 | Executive Vice President and Chief Financial Officer | Warner L. Baxter | 550,000 |
| 4 | | | |
| 5 | Senior Vice President | Daniel F. Cole | 340,000 |
| 6 | | | |
| 7 | Senior Vice President and Chief Accounting Officer | Martin J. Lyons | 305,000 |
| 8 | | | |
| 9 | Senior Vice President, General Counsel and Secretary | Steven R. Sullivan | 415,000 |
| 10 | | | |
| 11 | Vice President and Treasurer | Jerre E. Birdsong | 288,000 |
| 12 | | | |
| 13 | Vice President | Craig D. Nelson | 235,600 |
| 14 | | | |
| 15 | Vice President | Gregory L. Nelson | 294,500 |
| 16 | | | |
| 17 | Vice President | Stan E. Ogden | 166,500 |
| 18 | | | |
| 19 | Vice President | Ronald D. Pate | 182,300 |
| 20 | | | |
| 21 | Vice President | William J. Prebil | 190,900 |
| 22 | | | |
| 23 | Vice President and Controller | Bruce A. Steinke | 200,000 |
| 24 | | | |
| 25 | Vice President | Dennis W. Weisenborn | 187,200 |
| 26 | | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 *** | 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 | Steven R. Sullivan, Sr. Vice President, Gen. Counsel | 1901 Chouteau Avenue, St. Louis, MO 63103 |
| 8 | & Sec. *** | |
| 9 | Thomas R. Voss (Held the position of Director until | 1901 Chouteau Avenue, St. Louis, MO 63103 |
| 10 | April 22, 2008) | |
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| Name of Respondent | This Report Is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None

2. None

3. None

4. None

5. None

6. See Note 4 – Short-Term Borrowings and Liquidity, Note 5 – Long-Term Debt and Equity Financings and Note 14 – Related Party Transactions in "Combined Notes to Financial Statements." Included in Note 5 (above) is information regarding the issuance of $150,000,000 of 8.875% Senior Secured Notes on December 9, 2008. Illinois Commerce Commission approval is in Docket 08-0144 ($86,000,000), Docket 08-0564 ($14,300,000), and Docket 08-0591 ($50,000,000).

7. The Bylaws were amended effective July 28, 2008 to i) allow for shares of stock to be registered in uncertificated form, and ii) to modify the language as to the power and duties of the Chairman of the Board of Directors.

8. Local 51 Bargaining Unit Personnel during the third quarter of 2008, specifically beginning July 1st, were granted a 3% wage increase. The current estimated annual cost effect of this increase amounts to approximately $650,453 using total wages for 2007 as a base. This labor group comprises 272 employees.

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

10. None

11. (Reserved)

12. Not applicable.

13. Martin J. Lyons was elected Senior Vice President and Chief Accounting Officer effective January 1, 2008. Bruce A. Steinke was elected Vice President and Controller effective January 1, 2008. Effective April 22, 2008, Thomas R. Voss relinquished his position as a member of the Board of Directors.

14. None

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 1,458,186,249 | 1,407,593,870 |
| 3 | Construction Work in Progress (107) | 200-201 | 12,207,611 | 21,762,837 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 1,470,393,860 | 1,429,356,707 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200-201 | 914,934,143 | 883,766,199 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 555,459,717 | 545,590,508 |
| 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) | | 555,459,717 | 545,590,508 |
| 15 | Utility Plant Adjustments (116) | 122 | 0 | 0 |
| 16 | Gas Stored Underground - Noncurrent (117) | | 1,502,184 | 1,502,184 |
| 17 | **OTHER PROPERTY AND INVESTMENTS** | | | |
| 18 | Nonutility Property (121) | | 2,827,873 | 2,476,461 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 8,745 | 5,965 |
| 20 | Investments in Associated Companies (123) | | 0 | 0 |
| 21 | Investment in Subsidiary Companies (123.1) | 224-225 | 437,492,201 | 384,897,590 |
| 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) | | 8,419,182 | 6,858,361 |
| 25 | Sinking Funds (125) | | 0 | 0 |
| 26 | Depreciation Fund (126) | | 0 | 0 |
| 27 | Amortization Fund - Federal (127) | | 0 | 0 |
| 28 | Other Special Funds (128) | | 20,196,456 | 5,562,562 |
| 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 | 20,241,023 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 468,926,968 | 420,030,032 |
| 33 | **CURRENT AND ACCRUED ASSETS** | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 135,655 | 566,593 |
| 36 | Special Deposits (132-134) | | 1,500,000 | 1,500,000 |
| 37 | Working Fund (135) | | 1,200 | 3,254 |
| 38 | Temporary Cash Investments (136) | | 0 | 3,300,761 |
| 39 | Notes Receivable (141) | | 0 | 0 |
| 40 | Customer Accounts Receivable (142) | | 62,125,867 | 53,664,465 |
| 41 | Other Accounts Receivable (143) | | 944,335 | 1,312,616 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 2,626,455 | 2,391,358 |
| 43 | Notes Receivable from Associated Companies (145) | | 0 | 0 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 581,280 | 12,231,424 |
| 45 | Fuel Stock (151) | 227 | 34,614 | 38,825 |
| 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 | 7,563,043 | 7,135,178 |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 327,844 | 377,589 |
| 55 | Gas Stored Underground - Current (164.1) | | 74,875,525 | 52,125,846 |
| 56 | Liquefied Natural Gas Stored and Held for Processing (164.2-164.3) | | 0 | 0 |
| 57 | Prepayments (165) | | 547,117 | 840,478 |
| 58 | Advances for Gas (166-167) | | 0 | 0 |
| 59 | Interest and Dividends Receivable (171) | | 1 | 67,699 |
| 60 | Rents Receivable (172) | | 0 | 0 |
| 61 | Accrued Utility Revenues (173) | | 64,534,000 | 54,161,000 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 58,422 | 437,351 |
| 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) | | -5 | 21,977,028 |
| 66 | (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176 | | 1 | 20,241,023 |
| 67 | Total Current and Accrued Assets (Lines 34 through 66) | | 210,602,442 | 187,107,726 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 2,527,076 | 2,344,136 |
| 70 | Extraordinary Property Losses (182.1) | 230 | 0 | 0 |
| 71 | Unrecovered Plant and Regulatory Study Costs (182.2) | 230 | 0 | 0 |
| 72 | Other Regulatory Assets (182.3) | 232 | 157,154,002 | 21,761,907 |
| 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) | | 520 | -32 |
| 77 | Temporary Facilities (185) | | 0 | 0 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 14,213,753 | 10,281,975 |
| 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) | | 4,883,500 | 4,743,976 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 52,854,177 | 53,141,242 |
| 83 | Unrecovered Purchased Gas Costs (191) | | 0 | 805,302 |
| 84 | Total Deferred Debits (lines 69 through 83) | | 231,633,028 | 93,078,506 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 1,468,124,339 | 1,247,308,956 |

FOOTNOTE DATA

***Schedule Page: 110 Line No.: 31 Column: d***

Amount was incorrectly shown on line 30 as Long-Term Portion of Derivative Assets (175) in the prior year. The 12/31/2007 balance is now properly reported on line 31 as Long-Term Portion of Derivative Assets-Hedges (176).

| Name of Respondent | This Report is: | Date of Report (mo, da, yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Rresubmission | 04/17/2009 | end of 2008/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 | 35,587,400 |
| 4 | Capital Stock Subscribed (202, 205) | 252 | 0 | 0 |
| 5 | Stock Liability for Conversion (203, 206) | 252 | 0 | 0 |
| 6 | Premium on Capital Stock (207) | 252 | 0 | 0 |
| 7 | Other Paid-In Capital (208-211) | 253 | 243,167,330 | 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) | 254 | 0 | 0 |
| 11 | Retained Earnings (215, 215.1, 216) | 118-119 | 83,576,180 | 67,637,222 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118-119 | 156,989,794 | 104,677,642 |
| 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 | 591,952 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 688,515,200 | 637,323,042 |
| 17 | LONG-TERM DEBT | | | |
| 18 | Bonds (221) | 256-257 | 279,000,000 | 148,200,000 |
| 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) | | 360,384 | 382,932 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 278,639,616 | 147,817,068 |
| 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) | | 6,597,323 | 7,785,014 |
| 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) | | 19,327,942 | 3,916,742 |
| 32 | Long-Term Portion of Derivative Instrument Liabilities | | 0 | 0 |
| 33 | Long-Term Portion of Derivative Instrument Liabilities - Hedges | | 30,020,547 | 0 |
| 34 | Asset Retirement Obligations (230) | | 20,270,614 | 20,090,387 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 77,041,426 | 32,617,143 |
| 36 | CURRENT AND ACCRUED LIABILITIES | | | |
| 37 | Notes Payable (231) | | 0 | 115,000,000 |
| 38 | Accounts Payable (232) | | 41,630,063 | 27,989,481 |
| 39 | Notes Payable to Associated Companies (233) | | 200,000 | 0 |
| 40 | Accounts Payable to Associated Companies (234) | | 42,160,749 | 21,834,640 |
| 41 | Customer Deposits (235) | | 7,470,136 | 6,867,130 |
| 42 | Taxes Accrued (236) | 262-263 | 10,610,112 | 1,461,060 |
| 43 | Interest Accrued (237) | | 6,689,845 | 6,628,714 |
| 44 | Dividends Declared (238) | | 217,902 | 459,215 |
| 45 | Matured Long-Term Debt (239) | | 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<br>(2) [ ] A Rresubmission | 04/17/2009 | end of 2008/Q4 |

## 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) | | 585,380 | 513,299 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 6,506,110 | 5,151,521 |
| 49 | Obligations Under Capital Leases-Current (243) | | 0 | 0 |
| 50 | Derivative Instrument Liabilities (244) | | 4,998,810 | 66,797 |
| 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 0 | 0 |
| 52 | Derivative Instrument Liabilities - Hedges (245) | | 53,999,498 | 1,166,383 |
| 53 | (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges | | 30,020,547 | 0 |
| 54 | Total Current and Accrued Liabilities (lines 37 through 53) | | 145,048,058 | 187,138,240 |
| 55 | DEFERRED CREDITS | | | |
| 56 | Customer Advances for Construction (252) | | 11,182,897 | 10,691,518 |
| 57 | Accumulated Deferred Investment Tax Credits (255) | 266-267 | 3,332,525 | 4,018,141 |
| 58 | Deferred Gains from Disposition of Utility Plant (256) | | 0 | 0 |
| 59 | Other Deferred Credits (253) | 269 | 208,274,062 | 125,158,471 |
| 60 | Other Regulatory Liabilities (254) | 278 | -12,893,997 | 33,628,199 |
| 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) | | 79,807,518 | 73,460,426 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | -10,822,966 | -4,543,292 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 278,880,039 | 242,413,463 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 1,468,124,339 | 1,247,308,956 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

| 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 | 793,425,396 | 718,226,676 | | |
| 3 | Operating Expenses | | | | | |
| 4 | Operation Expenses (401) | 320-323 | 651,165,241 | 594,275,620 | | |
| 5 | Maintenance Expenses (402) | 320-323 | 28,051,973 | 20,010,834 | | |
| 6 | Depreciation Expense (403) | 336-337 | 48,466,969 | 53,077,277 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336-337 | | | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336-337 | 19,391 | 11,887 | | |
| 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) | | 6,797 | 433,276 | | |
| 13 | (Less) Regulatory Credits (407.4) | | | | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262-263 | 21,765,234 | 20,358,026 | | |
| 15 | Income Taxes - Federal (409.1) | 262-263 | 6,826,459 | 12,401,447 | | |
| 16 | - Other (409.1) | 262-263 | 2,385,450 | 839,268 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272-277 | 15,166,013 | 11,193,135 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272-277 | 18,351,288 | 26,235,473 | | |
| 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) | | 1,143,582 | 570,754 | | |
| 25 | TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24) | | 756,645,821 | 686,936,051 | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27 | | 36,779,575 | 31,290,625 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | Line No. |
|---|---|---|---|---|---|---|
| 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) | |
| | | | | | | 1 |
| 417,033,931 | 387,201,634 | 376,391,465 | 331,025,042 | | | 2 |
| | | | | | | 3 |
| 330,540,786 | 321,362,301 | 320,624,455 | 272,913,319 | | | 4 |
| 21,180,854 | 13,889,679 | 6,871,119 | 6,121,155 | | | 5 |
| 30,535,637 | 31,845,405 | 17,931,332 | 21,231,872 | | | 6 |
| | | | | | | 7 |
| 9,083 | 1,579 | 10,308 | 10,308 | | | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| 6,797 | 433,276 | | | | | 12 |
| | | | | | | 13 |
| 9,179,964 | 9,533,531 | 12,585,270 | 10,824,495 | | | 14 |
| 842,351 | 3,427,308 | 5,984,108 | 8,974,139 | | | 15 |
| 648,222 | -1,120,829 | 1,737,228 | 1,960,097 | | | 16 |
| 7,804,676 | 7,507,271 | 7,361,337 | 3,685,864 | | | 17 |
| 8,856,501 | 20,520,184 | 9,494,787 | 5,715,289 | | | 18 |
| | | | | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| | | | | | | 22 |
| | | | | | | 23 |
| 1,143,582 | 570,754 | | | | | 24 |
| 393,035,451 | 366,930,091 | 363,610,370 | 320,005,960 | | | 25 |
| 23,998,480 | 20,271,543 | 12,781,095 | 11,019,082 | | | 26 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | | 36,779,575 | 31,290,625 | | |
| 28 | Other Income and Deductions | | | | | |
| 29 | Other Income | | | | | |
| 30 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | | 11,476 | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | | | | |
| 33 | Revenues From Nonutility Operations (417) | | 313,662 | 421,976 | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 51,393 | 128,466 | | |
| 35 | Nonoperating Rental Income (418) | | | 175 | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | 52,594,611 | 64,941,229 | | |
| 37 | Interest and Dividend Income (419) | | 813,272 | 2,627,250 | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | -27,111 | 51,767 | | |
| 39 | Miscellaneous Nonoperating Income (421) | | 15,572,702 | 14,637,641 | | |
| 40 | Gain on Disposition of Property (421.1) | | 3,396 | -19,753 | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | 69,219,139 | 82,543,295 | | |
| 42 | Other Income Deductions | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | 9,546 | -13,413 | | |
| 44 | Miscellaneous Amortization (425) | 340 | | | | |
| 45 | Donations (426.1) | 340 | 565,773 | -2,502,203 | | |
| 46 | Life Insurance (426.2) | | 1,747,008 | 2,872,555 | | |
| 47 | Penalties (426.3) | | 20,067 | 452 | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 767,716 | 682,488 | | |
| 49 | Other Deductions (426.5) | | 17,749,576 | 16,838,878 | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 20,859,686 | 17,878,757 | | |
| 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 | -1,437,972 | 207,604 | | |
| 54 | Income Taxes-Other (409.2) | 262-263 | -323,532 | 46,837 | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272-277 | 4,414,117 | 3,584,497 | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272-277 | 2,663,678 | 1,260,285 | | |
| 57 | Investment Tax Credit Adj.-Net (411.5) | | -685,616 | -760,960 | | |
| 58 | (Less) Investment Tax Credits (420) | | | | | |
| 59 | TOTAL Taxes on Other Income and Deductions (Total of lines 52-58) | | -696,681 | 1,817,693 | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | 49,056,134 | 62,846,845 | | |
| 61 | Interest Charges | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 9,309,043 | 9,003,989 | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 416,058 | 413,922 | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 348,899 | 338,052 | | |
| 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) | 340 | | | | |
| 68 | Other Interest Expense (431) | 340 | 6,151,098 | 9,034,011 | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 27,734 | 636,007 | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 16,197,364 | 18,153,967 | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 69,638,345 | 75,983,503 | | |
| 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) | | 69,638,345 | 75,983,503 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | 67,637,222 | 58,991,716 |
| 2 | Changes | | | |
| 3 | Adjustments to Retained Earnings (Account 439) | | | |
| 4 | Redemption of Preferred Stock | Various | -33,000 | |
| 5 | Adoption of FIN 48 | Various | | ( 527,733) |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Credits to Retained Earnings (Acct. 439) | | -33,000 | ( 527,733) |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | TOTAL Debits to Retained Earnings (Acct. 439) | | | |
| 16 | Balance Transferred from Income (Account 433 less Account 418.1) | | 17,043,734 | 11,042,274 |
| 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 | | -1,354,235 | ( 1,869,035) |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | | | | |
| 29 | TOTAL Dividends Declared-Preferred Stock (Acct. 437) | | -1,354,235 | ( 1,869,035) |
| 30 | Dividends Declared-Common Stock (Account 438) | | | |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | TOTAL Dividends Declared-Common Stock (Acct. 438) | | | |
| 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) | | 83,576,180 | 67,637,222 |
| | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | | 83,576,180 | 67,637,222 |
| | UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account | | | |
| | Report only on an Annual Basis, no Quarterly | | | |
| 49 | Balance-Beginning of Year (Debit or Credit) | | 104,677,642 | 39,736,413 |
| 50 | Equity in Earnings for Year (Credit) (Account 418.1) | | 52,594,611 | 64,941,229 |
| 51 | (Less) Dividends Received (Debit) | | | |
| 52 | Transfer to Account 216 | | -282,459 | |
| 53 | Balance-End of Year (Total lines 49 thru 52) | | 156,989,794 | 104,677,642 |

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

Dividends Declared - Preferred Stock (Account 437)

| | Current Year 2008 | Prior Year 2007 |
|---|---|---|
| 4.50% Series | $ 500,688 | $ 500,688 |
| 4.64% Series | 370,922 | 370,921 |
| 5.85% Series | 482,625 | 997,426 |
| Total | $ 1,354,235 | $1,869,035 |

***Schedule Page: 118 Line No.: 52 Column: a***

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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 1 | Net Cash Flow from Operating Activities: | | |
| 2 | Net Income (Line 78(c) on page 117) | 69,638,345 | 75,983,503 |
| 3 | Noncash Charges (Credits) to Income: | | |
| 4 | Depreciation and Depletion | 49,629,942 | 53,659,918 |
| 5 | Amortization of Debt Issue Costs | 764,957 | 751,974 |
| 6 | Net mark-to-market (gain) loss on derivatives | 5,728,583 | |
| 7 | | | |
| 8 | Deferred Income Taxes (Net) | -1,434,836 | -12,718,126 |
| 9 | Investment Tax Credit Adjustment (Net) | -685,616 | -760,960 |
| 10 | Net (Increase) Decrease in Receivables | -5,413,182 | -20,926,100 |
| 11 | Net (Increase) Decrease in Inventory | -23,173,333 | 147,198 |
| 12 | Net (Increase) Decrease in Allowances Inventory | | |
| 13 | Net Increase (Decrease) in Payables and Accrued Expenses | 30,225,706 | -25,096,469 |
| 14 | Net (Increase) Decrease in Other Regulatory Assets | -590,354 | 19,099,335 |
| 15 | Net Increase (Decrease) in Other Regulatory Liabilities | | 817,874 |
| 16 | (Less) Allowance for Other Funds Used During Construction | -27,111 | 51,767 |
| 17 | (Less) Undistributed Earnings from Subsidiary Companies | 52,594,611 | 64,941,229 |
| 18 | Other (provide details in footnote): | | |
| 19 | Net (Increase) Decrease in Assets, other | -16,567,486 | -23,756,660 |
| 20 | Net Increase (Decrease) in Liabilities, other | 5,215,089 | 8,012,393 |
| 21 | | | |
| 22 | Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21) | 60,770,315 | 10,220,884 |
| 23 | | | |
| 24 | Cash Flows from Investment Activities: | | |
| 25 | Construction and Acquisition of Plant (including land): | | |
| 26 | Gross Additions to Utility Plant (less nuclear fuel) | -61,718,222 | -63,366,171 |
| 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 | 27,111 | -51,767 |
| 31 | Other (provide details in footnote): | | |
| 32 | | | |
| 33 | | | |
| 34 | Cash Outflows for Plant (Total of lines 26 thru 33) | -61,745,333 | -63,314,404 |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(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 | Dividends received from subsidiaries | | 10,000,000 |
| 55 | | | |
| 56 | Net Cash Provided by (Used in) Investing Activities | | |
| 57 | Total of lines 34 thru 55) | -61,745,333 | -53,314,404 |
| 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) | | 65,000,000 |
| 67 | Other (provide details in footnote): | | |
| 68 | Capital Contribution | | 15,254,000 |
| 69 | | | |
| 70 | Cash Provided by Outside Sources (Total 61 thru 69) | 149,095,500 | 80,254,000 |
| 71 | | | |
| 72 | Payments for Retirement of: | | |
| 73 | Long-term Debt (b) | -19,200,000 | -50,000,000 |
| 74 | Preferred Stock | -16,500,000 | -1,100,000 |
| 75 | Common Stock | | |
| 76 | Other (provide details in footnote): | | |
| 77 | Contributions and Advances from Associate and Subsidiary Companies | 200,000 | 19,500,000 |
| 78 | Net Decrease in Short-Term Debt (c) | -115,000,000 | |
| 79 | | | |
| 80 | Dividends on Preferred Stock | -1,354,235 | -1,869,035 |
| 81 | Dividends on Common Stock | | |
| 82 | Net Cash Provided by (Used in) Financing Activities | | |
| 83 | (Total of lines 70 thru 81) | -2,758,735 | 46,784,965 |
| 84 | | | |
| 85 | Net Increase (Decrease) in Cash and Cash Equivalents | | |
| 86 | (Total of lines 22,57 and 83) | -3,733,753 | 3,691,445 |
| 87 | | | |
| 88 | Cash and Cash Equivalents at Beginning of Period | 3,870,608 | 179,163 |
| 89 | | | |
| 90 | Cash and Cash Equivalents at End of period | 136,855 | 3,870,608 |

| Name of Respondent | This Report Is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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)**
**CILCORP INC. (Consolidated)**
**CENTRAL ILLINOIS LIGHT COMPANY (Consolidated)**
**ILLINOIS POWER COMPANY (Consolidated)**

**COMBINED NOTES TO FINANCIAL STATEMENTS**
**December 31, 2008**

**(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 rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and non-rate-regulated electric generation businesses in Missouri and Illinois. Dividends on Ameren's common stock and the payment of other expenses by the Ameren and CILCORP holding companies 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 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 1902. It supplies electric and 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 393,000 customers and natural gas service to 185,000 customers.
- Genco, or Ameren Energy Generating Company, operates a non-rate-regulated electric generation business in Illinois and Missouri. Genco was incorporated in Illinois in March 2000. Genco owns 2,557 megawatts of coal-fired electric generating capacity and 1,663 megawatts of natural gas and oil-fired electric generating capacity.
- CILCO, or Central Illinois Light Company, also known as AmerenCILCO, is a subsidiary of CILCORP (a holding company). It operates a rate-regulated electric transmission and distribution business, a non-rate-regulated electric generation business, and a rate-regulated natural gas transmission and distribution business in Illinois. CILCO was incorporated in Illinois in 1913. It supplies electric and gas utility service to portions of central and east central Illinois in areas of 3,700 and 4,500 square miles, respectively, with an estimated population of 0.6 million. CILCO supplies electric service to 214,000 customers and natural gas service to 216,000 customers. AERG, a non-rate-regulated wholly-owned subsidiary of CILCO, owns 1,125 megawatts of coal-fired electric generating capacity and 15 megawatts of oil-fired electric generating capacity. CILCORP was incorporated in Illinois in 1985.
- 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 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 627,000 customers and natural gas service to 421,000 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. 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, | 2008 | 2007 | 2006 |
|---|---|---|---|
| Operating revenues | **$ 520** | $ 427 | $ 371 |
| Operating income | **226** | 216 | 227 |
| Net income | **142** | 136 | 136 |
| **As of December 31,** | | | |
| Current assets | **$ 76** | $ 69 | $ 58 |
| Noncurrent assets | **140** | 124 | 108 |
| Current liabilities | **93** | 60 | 70 |
| Noncurrent liabilities | **43** | 10 | 17 |

The financial statements of Ameren, Genco, CILCORP and CILCO are prepared on a consolidated basis. CIPS has no subsidiaries and therefore is not consolidated. UE had a subsidiary in 2007 and 2006 (Union Electric Development Corporation), but in January 2008 this subsidiary was transferred to Ameren in the form of a stock dividend. In March 2008 it was merged into an Ameren nonregistrant subsidiary. Accordingly, UE's financial statements were prepared on a consolidated basis for 2007 and 2006 only. IP had a subsidiary in 2007 and 2006 (Illinois Gas Supply Company) that was dissolved at December 31, 2007. Accordingly, IP's financial statements were prepared on a consolidated basis for 2007 and 2006 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 SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," UE, CIPS, CILCO and IP defer certain costs pursuant to actions of our rate regulators. These companies are currently recovering such costs in rates charged to customers. See Note 2 - Rate and Regulatory Matters for further information.

**Cash and Cash Equivalents**

Cash and cash equivalents include cash on hand and temporary investments purchased with an original maturity of three months or less.

**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 collections environment.

**Materials and Supplies**

Materials and supplies are recorded at the lower of cost or market. Cost is determined using the average-cost method. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. The following table presents a breakdown of materials and supplies for each of the Ameren Companies at December 31, 2008 and 2007:

| | Ameren[a] | UE | CIPS | Genco | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|---|
| **2008:** | | | | | | | |
| Fuel[b] | **$ 290** | **$ 139** | **$ -** | **$ 92** | **$ 32** | **$ 32** | **$ -** |
| Gas stored underground | **277** | **32** | **54** | **-** | **75** | **75** | **117** |
| Other materials and supplies | **275** | **168** | **16** | **30** | **24** | **24** | **27** |
| | **$ 842** | **$ 339** | **$ 70** | **$ 122** | **$ 131** | **$ 131** | **$ 144** |
| **2007:** | | | | | | | |
| Fuel[b] | $ 253 | $ 129 | $ - | $ 67 | $ 36 | $ 36 | $ - |
| Gas stored underground | 245 | 30 | 52 | - | 52 | 52 | 110 |
| Other materials and supplies | 237 | 142 | 14 | 26 | 22 | 22 | 24 |
| | $ 735 | $ 301 | $ 66 | $ 93 | $ 110 | $ 110 | $ 134 |

(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, or the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to rate-regulated construction expenditures, is also added for our rate-regulated assets. Interest during construction is added for non-rate-regulated 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 value, are charged to accumulated depreciation. Asset removal costs incurred by our non-rate-regulated 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 further information.

**Depreciation**

Depreciation is provided over the estimated lives of the various classes of depreciable property by applying composite rates on a straight-line basis. The provision for depreciation for the Ameren Companies in 2008, 2007 and 2006 generally ranged from 3% to 4% of the average depreciable cost. Due to the ICC consolidated electric and gas rate order that became effective on October 1, 2008, annual depreciation expense for the Ameren Illinois Utilities will be reduced for financial reporting purposes by a net $13 million in the aggregate (CIPS - $4 million reduction, CILCO - $26 million reduction, and IP - $17 million increase).

**Allowance for Funds Used During Construction**

In our rate-regulated operations, we capitalize the allowance for funds used during construction, 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 allowance for funds used during construction rates that were utilized during 2008, 2007 and 2006:

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Ameren | **1% - 7%** | 6% - 7% | 6% - 9% |
| UE | **7** | 6 | 6 |
| CIPS | **1** | 6 | 9 |
| CILCORP/CILCO | **1** | 7 | 6 |
| IP | **5** | 6 | 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. As of December 31, 2008, Ameren, CILCORP, and IP had goodwill of $831 million, $542 million, and $214 million, respectively. Ameren's and IP's goodwill relates to the acquisition of IP in 2004. Ameren's and CILCORP's goodwill relates to the acquisition of CILCORP in 2003. Ameren's goodwill also includes an additional 20% ownership interest in EEI acquired in 2004 as well as the acquisition of Medina Valley in 2003.

In accordance with the specific provisions of SFAS No. 142, "Goodwill and Other Intangible Assets," we test goodwill for impairment at the reporting unit level. Ameren has identified three reporting units, which also represent Ameren's reportable segments and operating segments under SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information." The Ameren reporting units include Missouri Regulated, Illinois Regulated, and Non-rate-regulated Generation. Ameren's reporting units have been defined and goodwill is evaluated at the operating segment level because we believe the components within each operating segment have similar economic characteristics. The following table details how goodwill has been assigned to the reporting units:

| | Missouri Regulated | Illinois Regulated | Non-rate-regulated Generation | Total |
|---|---|---|---|---|
| Ameren | $ - | $ 411 | $ 420[(a)] | $ 831[(a)] |
| CILCORP | - | 197 | 345 | 542 |
| IP | - | 214 | - | 214 |

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

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. Impairment testing of goodwill 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, the second step is performed to measure the amount of impairment, if any. The second step requires a calculation of the implied fair value of goodwill.

The goodwill impairment test performed in the fourth quarter of 2008 did not require a second step assessment; it indicated no impairment of Ameren's, CILCORP's or IP's goodwill. The fair value of Ameren's, CILCORP's and IP's reporting units was estimated based on a 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 future cash flows, and an exit value based on observable market multiples. We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, the regulatory environment, and operating costs. The failure to achieve projected future operating results and cash flows, or adjustments to other valuation assumptions, could change our estimate of reporting unit fair value, in which case we might be required, at a later date, to record an impairment charge related to goodwill.

At Ameren and IP, 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 any of the reporting units exceeding their fair values.

The estimated fair values of CILCORP's Illinois Regulated reporting unit and Non-rate-regulated Generation reporting unit exceeded carrying values by a nominal amount as of October 31, 2008. As a result, the failure in the future of either of these reporting units to achieve forecasted operating results and cash flows may reduce its estimated fair value below its carrying value and would likely result in the recognition of a goodwill impairment charge. CILCORP will continue to monitor the actual and forecasted operating results and cash flows and observable market multiples of these reporting units for signs of possible declines in estimated fair value and potential goodwill impairment. Ameren would not necessarily expect any future goodwill impairment charge recorded at the CILCORP reporting unit level to also result in a goodwill impairment charge at the consolidated Ameren level because of the aggregation of reporting units.

*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, CILCORP's and CILCO's intangible assets at December 31, 2008 and 2007, 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, 2008. Emission allowances consist of various individual emission allowance

certificates and do not have expiration dates. 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) | 3,014,000 | 15,035 | $ 167(e) |
| UE | 1,640,000 | 5,505 | 48 |
| Genco | 720,000 | 8,125 | 49 |
| CILCORP(f) | 337,000 | 209 | 35 |
| CILCO (AERG) | 337,000 | 209 | 1 |
| EEI | 317,000 | 1,196 | 9 |

(a) Vintages are from 2008 to 2018. Each company possesses additional allowances for use in periods beyond 2018.
(b) Vintage is 2008.
(c) The book value at December 31, 2008, represents $SO_2$ and $NO_X$ emission allowances for use in periods through 2031. The book value at December 31, 2007, for Ameren, UE, Genco, CILCORP, CILCO (AERG), and EEI was $198 million, $56 million, $63 million, $41 million, $1 million, and $9 million, respectively.
(d) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(e) Includes $26 million of fair-market value adjustments recorded in connection with Ameren's acquisition of an additional 20% ownership interest in EEI.
(f) Includes fair-market value adjustments recorded in connection with Ameren's acquisition of CILCORP.

The following table presents the amortization expense based on usage of emission allowances, net of gains from emission allowance sales, for Ameren, UE, Genco, CILCORP, and CILCO (AERG) during the years ended December 31, 2008, 2007, and 2006.

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Ameren(a)(b) | **$ 28** | $ 35 | $ (3) |
| UE | **(5)** | (5) | (34) |
| Genco | **25** | 30 | 30 |
| CILCORP(b) | **6** | 7 | 21 |
| CILCO (AERG) | **(c)** | 1 | 11 |

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(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 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 the amount of the impairment by estimating the fair value of the assets and recording a provision for loss. During the fourth quarter of 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 cogeneration 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 based on the expected net proceeds to be generated from the sale of the facility in 2009. These charges were recorded in Operating Expenses - Other Operations and Maintenance Expense in the applicable statements of income and were included with Non-rate-regulated 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 we believe would be recovered in electric rates paid by UE's 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**

Environmental costs are recorded on an undiscounted basis when it is probable that a liability has been incurred and that 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 gas service when it is delivered to customers. We accrue an estimate of electric and 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 and Purchased Gas Costs**

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.

In UE's, CIPS', CILCO's, and IP's retail natural gas utility jurisdictions, changes in 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 in the balance sheets of UE, CIPS, CILCO and IP. The deferred amounts are either billed or refunded to their natural gas utility customers prospectively 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 due to 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 SEC Staff Accounting Bulletin No. 101, "Revenue Recognition in Financial Statements."

**Stock-based Compensation**

In accounting for stock-based compensation, Ameren measures the cost of employee services received in exchange for an award of equity instruments by the grant-date fair value of the award over the requisite service period.

See Note 12 - Stock-based Compensation for further information.

**Excise Taxes**

Excise taxes imposed on us are reflected on Missouri electric, Missouri gas, and Illinois 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 Operating Expenses - Taxes Accrued. The following table presents excise taxes recorded in Operating Revenues and Operating Expenses - Taxes Other than Income Taxes for the years ended 2008, 2007 and 2006:

| | 2008 | 2007 | 2006 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Ameren | **$ 172** | $ 166 | $ 169 |
| UE | **109** | 110 | 106 |
| CIPS | **16** | 15 | 16 |
| CILCORP | **13** | 11 | 12 |
| CILCO | **13** | 11 | 12 |
| IP | **34** | 30 | 35 |

**Income Taxes**

Ameren uses an asset and liability approach for its financial accounting and reporting of income taxes, in accordance with the provisions of SFAS No. 109, "Accounting for Income Taxes." Deferred tax assets and liabilities are recognized for transactions that are treated differently for financial reporting and tax return purposes. These deferred tax assets and liabilities are determined by 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 due to 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 SFAS No. 109.

Investment tax credits used on tax returns for prior years have been deferred for book purposes; they are being amortized over the useful lives of the related properties. 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, CILCORP, 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 to the capital of the party receiving the benefit.

**Minority Interest and Preferred Dividends of Subsidiaries**

For the years ended December 31, 2008, 2007, and 2006, Ameren had minority interest expense related to EEI of $29 million, $27 million, and $27 million, respectively, and preferred dividends of subsidiaries of $10 million, $11 million, and $11 million, respectively.

**Earnings per Share**

There were no material differences between Ameren's basic and diluted earnings per share amounts in 2008, 2007, and 2006. 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, 35,545 shares in 2007, and 38,438 shares in 2006.

**Accounting Changes and Other Matters**

SFAS No. 157, *Fair Value Measurements*

In September 2006, the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value, and expands required disclosures about fair value measurements. SFAS No. 157 clarifies that fair value is a market-based measurement that should be based on the assumptions that market participants would use in pricing an asset or liability. See Note 8 - Fair Value Measurements for additional information on our adoption of SFAS No. 157.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of SFAS No. 115*

In February 2007, the FASB issued SFAS No. 159, which permits companies to choose to measure at fair value many financial instruments and certain assets and liabilities that are not currently required to be measured at fair value on an instrument-by-instrument basis. Entities electing the fair

value option will be required to recognize changes in fair value in earnings and to expense upfront cost and fees associated with the item for which the fair value option is elected. SFAS No. 159 was effective as of the beginning of our 2008 fiscal year. We did not elect the fair value option for any of our eligible financial instruments or other items.

FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*

In April 2007, the FASB issued FSP FIN 39-1, effective for us as of the beginning of our 2008 fiscal year. FSP FIN 39-1 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. We did not elect to adopt FSP FIN 39-1 for any of our eligible financial instruments or other items.

SFAS No. 141 (Revised 2007), *Business Combinations*

In December 2007, the FASB issued SFAS No. 141(R), which replaces SFAS No. 141. SFAS No. 141(R) applies to all transactions in which an entity obtains control of one or more businesses and combinations without the transfer of consideration. SFAS No. 141(R) requires the acquiring entity in a business combination to recognize assets acquired and liabilities assumed in the transaction at fair value; it requires certain contingent assets and liabilities acquired be recognized at their fair values on the acquisition date; and it requires expensing of acquisition-related costs as incurred, among other provisions. SFAS No. 141(R) was effective as of January 1, 2009. It applies prospectively to business combinations completed on or after that date.

SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*

In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards for minority interests, which will be recharacterized as noncontrolling interests. Under the provisions of SFAS No. 160, noncontrolling interests will 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 will be accounted for as equity transactions; net income attributable to the noncontrolling interest will 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, will be recorded at fair value, with any gain or loss recognized in earnings. SFAS No. 160 was effective for us as of the beginning of our 2009 fiscal year. It applies prospectively, except for the presentation and disclosure requirements, for which it applies retroactively. This standard is applicable to the minority interest in EEI, as EEI is 80% owned by Ameren.

SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities - an amendment of SFAS No. 133*

In March 2008, the FASB issued SFAS No. 161, which requires enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS No. 161 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. SFAS No. 161 was effective in the first quarter of 2009. The adoption of SFAS No. 161 did not have a material impact on our results of operations, financial position, or liquidity, because it provides enhanced disclosure requirements only.

FSP SFAS No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*

In October 2008, the FASB issued FSP SFAS No. 157-3, which clarifies the application of SFAS No. 157 in a market that is not active. FSP SFAS No. 157-3 provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP SFAS No. 157-3 was effective upon issuance, and it applied retroactively to periods for which financial statements had not yet been issued. The adoption of FSP SFAS No. 157-3 did not have a material impact on our results of operations, financial condition, or liquidity.

FSP SFAS No. 140-4 and FIN 46(R), *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities*

In December 2008, FASB issued FSP SFAS No. 140-4 and FIN 46(R), effective for us as of December 31, 2008. FSP SFAS No. 140-4 and FIN 46(R) require enhanced qualitative and quantitative information about an enterprise's involvement with a variable-interest entity (VIE) and its

continuing involvement with transferred financial assets. For VIEs, enhanced qualitative and quantitative information about an enterprise's involvement with a VIE, financial or other support provided by the enterprise to the VIE, and the methodology applied in determining whether an enterprise is the primary beneficiary should be disclosed. See Variable-interest Entities below for further information.

FSP SFAS No. 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*

In December 2008, FASB issued FSP SFAS No. 132(R)-1, which will be effective for us as of December 31, 2009. FSP SFAS No. 132(R)-1 requires additional disclosures related to pension and other postretirement benefit plan assets. Additional disclosures include the investment allocation decision-making process, the fair value of each major category of plan assets as well as the inputs and valuation techniques used to measure fair value and significant concentrations of risk within the plan assets. The adoption of FSP SFAS No. 132(R)-1 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**

SFAS No. 143, "Accounting for Asset Retirement Obligations," and FIN 47, "Accounting for Conditional Asset Retirement Obligations" - an Interpretation of FASB Statement No. 143, require 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 in AROs based on changes in estimated fair value. Corresponding increases in asset book values are depreciated over the remaining useful life of the related asset. Uncertainties as to the probability, timing, or amount of cash flows associated with AROs affect our estimates of fair value. Ameren, UE, Genco, CILCORP, 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 2008 and 2007:

| | Ameren[(a)(b)] | UE[(b)] | CIPS | Genco | CILCORP/ CILCO | IP |
|---|---|---|---|---|---|---|
| Balance at December 31, 2006 | $ 553 | $ 491 | $ 2 | $ 35 | $ 17 | $ 2 |
| Liabilities incurred | 1 | 1 | - | - | - | - |
| Liabilities settled | (2) | (1) | - | (1) | (c) | - |
| Accretion in 2007[(d)] | 32 | 28 | (c) | 2 | 1 | (c) |
| Change in estimates[(e)] | (17) | (43) | (c) | 16 | 10 | - |
| Balance at December 31, 2007 | $ 567 | $ 476 | $ 2 | $ 52 | $ 28 | $ 2 |
| Liabilities settled | **(4)** | **(c)** | **-** | **(1)** | **(2)** | **(c)** |
| Accretion in 2008[(d)] | **33** | **27** | **(c)** | **3** | **2** | **(c)** |
| Change in estimates[(f)] | **(186)** | **(186)** | **-** | **(c)** | **(c)** | **-** |
| Balance at December 31, 2008 | **$ 410** | **$ 317** | **$ 2** | **$ 54** | **$ 28** | **$ 2** |

(a) Ameren amounts do not equal total due to AROs at EEI.
(b) The nuclear decommissioning trust fund assets of $239 million and $307 million as of December 31, 2008 and 2007, respectively, are restricted for decommissioning of the Callaway nuclear plant.
(c) Less than $1 million.
(d) Substantially all accretion expense was recorded as an increase to regulatory assets.
(e) UE, Genco and CILCO changed estimates related to retirement costs for their ash ponds. Additionally, UE changed estimates related to its Callaway nuclear plant decommissioning costs.
(f) 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.

**Variable-interest Entities**

According to FIN 46R, "Variable-interest Entities," an entity is considered a variable-interest entity (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 its equity interests, debt obligations, leases, contracts, and other agreements to determine its relationship to a VIE. We

have determined that the following significant VIEs were held by the Ameren Companies at December 31, 2008:

- *Leveraged lease and affordable housing partnership investments*. Ameren has investments in affordable housing and low-income real estate development partnership arrangements that are variable interests. Ameren also has an investment in a leveraged lease. 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. At December 31, 2008, and December 31, 2007, Ameren had investments in affordable housing and low-income real estate development partnerships of $82 million and $100 million, respectively. At December 31, 2008, and December 31, 2007, Ameren had a net investment in a leveraged lease of $9 million. 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. In 2008, a subsidiary of UE that owned affordable housing partnerships was eliminated in an internal reorganization. Those investments were transferred to a nonregistrant Ameren subsidiary.

IP's variable interest in IP SPT was eliminated, as the TFNs for which the IP SPT was established were redeemed in September 2008. IP had indemnified IP SPT; IP was liable to IP SPT if IP did not bill the applicable charges to its customers on behalf of IP SPT or if it did not remit the collections to IP SPT. However, the note holders were considered the primary beneficiaries of this special-purpose trust. Accordingly, Ameren and IP did not consolidate IP SPT.

**Coal Contract Settlement**

In June 2008, Genco entered into an agreement with a coal mine owner. The owner provided Genco with a lump-sum payment of $60 million in July 2008 due to the coal supplier's premature closing of a mine and the early termination of a coal supply contract. The settlement agreement compensates Genco, in total, for higher fuel costs it incurred in 2008 ($33 million) and expects to incur in 2009 ($27 million) as a result of the mine closure and contract termination.

**NOTE 2 - RATE AND REGULATORY MATTERS**

Below is a summary of significant regulatory proceedings and related lawsuits. We are unable to predict the ultimate outcome of these matters, the timing of the final decisions of the various agencies and courts, or the impact on our results of operations, financial position, or liquidity.

**Missouri**

*2007 Electric Rate Order*

In May 2007, the MoPSC issued an order, as clarified, granting UE a $43 million increase in base rates for electric service based on a return on equity of 10.2% and a capital structure of 52% common equity. New electric rates became effective June 4, 2007.

In July 2007, UE and other parties appealed certain aspects of the MoPSC decision, to the Circuit Court of Cole County in Jefferson City, Missouri and subsequently to the Court of Appeals for the Western District of Missouri. In January 2009, the Court of Appeals for the Western District of Missouri issued an order affirming, in all respects, the order issued by the MoPSC in May 2007, and the time to appeal this court decision has expired.

*2009 Electric Rate Order*

In April 2008, UE filed a request with the MoPSC to increase its annual revenues for electric service by $251 million. The electric rate increase request proposed an average increase in electric rates of 12.1%. It was based on a 10.9% return on equity, a capital structure composed of 52% common equity, a rate base of $5.9 billion, and a test year ended March 31, 2008, with updates for known and measurable changes through September 30, 2008.

As part of the proceeding, UE requested that the MoPSC also approve implementation of a FAC and a vegetation management and infrastructure inspection cost recovery mechanism.

On January 27, 2009, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $162 million based on a 10.76% return on equity, a capital structure composed of 52% common equity, and a rate base of $5.8 billion. The rate changes necessary to implement the provisions of the MoPSC's order were effective March 1, 2009, with the MoPSC's acceptance of conforming tariffs filed by UE. The MoPSC order also included the following significant provisions:

- Approval of the implementation of a FAC. The mechanism provides for the 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, above or below the amount set in base rates, subject to MoPSC prudency review.
- Approval of the implementation of a vegetation management and infrastructure inspection cost tracking mechanism. The mechanism provides for the tracking of expenditures that are more or less than amounts provided for in UE's annual revenues for electric service in a particular year, subject to a 10% limitation on increases in any one year. The tracked amounts may be reflected in rates set in future rate cases.
- Pursuant to an accounting order issued by the MoPSC in April 2008 that gave UE the ability to seek direct recovery of all or a portion of operations and maintenance expenses incurred as a result of a severe ice storm in January 2007, the rate order concluded that the $25 million of operations and maintenance expenses incurred as a result of the severe ice storm should be amortized and recovered over a five-year period starting March 1, 2009. UE recorded these costs as a regulatory asset in 2008.
- Allowance for recovery of $12 million of costs associated with a March 2007 FERC order that resettled costs among MISO market participants. The costs were previously expensed. A regulatory asset was recorded at December 31, 2008, and will be amortized over a two-year period starting March 1, 2009.

UE provides power to Noranda's smelter plant in New Madrid, Missouri. This plant has historically used approximately four million megawatthours of power annually, making Noranda UE's single largest customer and constituting approximately 8% of UE's total electric sales.

As a result of a major winter ice storm in Southeastern Missouri in January 2009, Noranda's smelter plant experienced a power outage related to non-UE lines delivering power to the substation serving the plant. Noranda stated that the outage affected approximately 75% of the smelter plant's capacity. In addition, Noranda stated that based on preliminary information and management's initial assessment, restoring full plant capacity may take up to 12 months, with partial capacity phased in during the 12 month period.

To the extent UE's sales to Noranda are reduced, generation made available could be sold as off-system sales. However, the FAC approved in the January 2009 electric rate order would require UE to pass through substantially all of the off-system revenues to customers.

In order to adjust the FAC for this unanticipated event, UE sought rehearing by the MoPSC of its January 2009 electric rate order on February 5, 2009, to allow UE to first recover from the off-system sales any revenues it would lose as a result of the reduced tariff sales to Noranda with any excess revenues collected being provided to customers through the FAC. Also in February 2009, other parties to the rate case filed for rehearing of certain aspects of the MoPSC order. In February 2009, the MoPSC denied all rate order rehearing requests filed by UE and other parties. UE continues to consider other alternatives to recover any lost revenues resulting from the Noranda power outage. UE cannot predict whether court appeals will be filed by other parties to the rate case.

*Environmental Cost Recovery Mechanism*

A Missouri law enacted in July 2005 enables the MoPSC to put in place an environmental cost recovery mechanism for Missouri's utilities. The law also includes rate case filing requirements, a 2.5% annual rate increase cap for the environmental cost recovery mechanism, and prudency reviews, among other things. The MoPSC initiated a proceeding in December 2008 to develop revised rules for the cost recovery mechanism. Rules for the environmental cost recovery mechanism are expected to be approved by the MoPSC during the second quarter of 2009 and will be effective once published in the Missouri Register. UE will not be able to implement an environmental cost recovery mechanism until so authorized by the MoPSC as part of a rate case proceeding.

*Renewable Energy Portfolio Requirement*

A ballot initiative passed by Missouri voters in November 2008 that 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 are required to be issued by the MoPSC to implement the law. UE expects that any related costs or investments would ultimately be recovered in rates.

**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 10.68% return on equity with respect to natural gas delivery service. These rate changes were effective on October 1, 2008. Because of the Ameren Illinois Utilities' pledge to keep the overall residential electric bill increase resulting from these rate changes to less than 10% for each utility during the first year, IP will not be able to recover approximately $10 million in revenue in the first year electric delivery service rates are in effect. Thereafter, residential electric delivery service rates will be adjusted to recover the full increase.

In addition, the ICC in its order changed the depreciable lives used in calculating depreciation expense for the Ameren Illinois Utilities' electric and natural gas rates. As a result, annual depreciation expense for the Ameren Illinois Utilities will be reduced for financial reporting purposes by a net $13 million in the aggregate (CIPS - $4 million reduction, CILCO - $26 million reduction, and IP - $17 million increase).

The ICC rejected the Ameren Illinois Utilities' requested rate adjustment mechanisms for electric infrastructure investments. As an alternative to the Ameren Illinois Utilities' requested decoupling of natural gas revenues from sales volumes, the ICC order approved an increase in the percentage of costs to be recovered through fixed non-volumetric residential and commercial customer charges, to 80% from 53%. This increase will impact 2009 quarterly results of operations and cash flows, but is not expected to have any impact on annual margins. The ICC also approved an increase in the Supply Cost Adjustment (SCA) factors for the Ameren Illinois Utilities. The SCA is a charge applied only to the bills of customers who take their power supply from the Ameren Illinois Utilities. The change in the SCA factors is expected to result in increased electric revenues of $9.5 million per year in the aggregate (CIPS - $2.6 million, CILCO - $1.6 million, and IP - $5.3 million), which is expected to cover the increased cost of administering the Ameren Illinois Utilities' power supply responsibilities.

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 to the Appellate Court of Illinois, Fourth District, the ICC's denial of the rehearing request. The Ameren Illinois Utilities cannot predict the outcome of the court appeal.

*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 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 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, 2008.

The Ameren Illinois Utilities, Genco, and CILCO (AERG) recognize in their financial statements the costs of their respective rate relief contributions and program funding in a manner corresponding with the timing of the funding. 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, 2008, of $42 million, $6 million, $3 million, $8 million, $17 million, and $8 million, respectively (year ended December 31, 2007 - $82 million, $12 million, $7 million, $15 million, $33 million, and $15 million, respectively) under the terms of the 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 first prior to seeking reimbursement from the generators. At December 31, 2008, Ameren, CIPS, CILCO (Illinois Regulated) and IP had receivable balances from nonaffiliated Illinois generators for reimbursement of customer rate relief and program funding of $15 million, $5 million, $3 million, and $7 million, respectively. See Note 14 - Related Party Transactions for information on the impact of intercompany settlements.

The Illinois electric settlement agreement provides that if legislation is enacted in Illinois before August 1, 2011, 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 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 Plan*

As part of the Illinois electric settlement agreement, the reverse auction used for power procurement in Illinois was discontinued. It was replaced with a new power procurement process led by the IPA, which was established as a part of the Illinois electric settlement agreement, beginning in 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 (capacity, energy swaps and renewable energy credits) that the IPA will procure on behalf of the Ameren Illinois Utilities for the period June 1, 2009, through May 30, 2014. The products are expected to be procured through a RFP process during the first half of 2009.

Except for those that expired in May 2008, existing supply contracts from the September 2006 reverse power procurement auction remain in place. In the September 2006 auction, the Ameren Illinois Utilities procured power to serve the electric load needs of fixed-price residential and small commercial customers, with one-third of the supply contracts expiring in each of May 2008, 2009, and 2010. The Ameren Illinois Utilities used RFP processes in early 2008 to replace the supply contracts that expired in May 2008. See Note 15 - Commitments and Contingencies for information on the Ameren Illinois Utilities' purchased power agreements.

Also as part of the 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 14 - Related Party Transactions for information on these financial contracts.

*Natural Gas Energy Efficiency Plans*

In February 2008, the Ameren Illinois Utilities filed a consolidated natural gas energy efficiency plan with the ICC. In October 2008, the ICC issued an order approving the Ameren Illinois Utilities' natural gas energy efficiency plan as well as the cost recovery mechanism by which the program costs will be recovered from natural gas customers. The natural gas energy efficiency plan includes annual reduction targets in natural gas usage as well as spending limits for the 2009, 2010, and 2011 program years of $2 million, $4 million, and $6 million, respectively.

*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. The Ameren Illinois Utilities are currently in discussions with the ICC and Liberty Consulting Group about this matter. Liberty Consulting Group will monitor the Ameren Illinois Utilities' efforts to implement the recommendations and any initiatives that the Ameren Illinois Utilities undertake. At this time, we are unable to determine the impact such implementation will have on our results of operations, financial position, or liquidity.

**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 receive 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 permit 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 provides 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.

*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 the MISO and PJM for revenues lost when FERC eliminated the regional through-and-out rates previously applicable to transactions crossing the border between the 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). 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 charge of $10 million, $3 million, $1 million, and $6 million, respectively. CILCO's net SECA charges were less than $1 million. Until FERC acts on the pending settlements and issues a final order on the initial decision, we cannot predict the ultimate impact of the SECA proceedings 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 granted the request for clarification and directed MISO to reallocate certain costs and provide refunds as requested. On November 10, 2008, FERC granted relief requested in the complaints filed by UE, CIPS, CILCO, IP and others regarding these same MISO operational charges and directed MISO to calculate refunds for the period from August 10, 2007, forward.

Several parties to these proceedings have protested MISO's proposed implementation of these refunds, have requested rehearing of FERC's orders and, in some cases, have appealed FERC's orders to the courts. Additional amounts may be receivable or due depending on the final outcome of these proceedings.

*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, which 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. Additional charges are expected to continue during the remainder of the term of the power purchase agreement, which expires August 25, 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 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 is just and reasonable. FERC is expected to issue an order with respect to the administrative law judge's initial decision in 2009. UE is unable to predict whether FERC will grant it any relief.

Additionally, LPSC appealed FERC's orders regarding LPSC's complaint against Entergy 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 decision. 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. However, UE would contest such an order vigorously. 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, 2008. UE plans to participate in any proceeding that FERC initiates to address the court's decision.

*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 potential new 1,600 megawatt nuclear unit at UE's existing Callaway County, Missouri, nuclear plant site. This COLA filing is not a commitment to build another nuclear unit, but it is a necessary step to preserve the option to develop a new nuclear unit in the future. The regulatory process for a COLA involves a comprehensive review, estimated by the NRC to require up to 42 months for completion.

As authorized by the Energy Policy Act of 2005, the DOE may make available up to $18.5 billion in loan guarantees in connection with debt financing of certain new nuclear unit projects. Pursuant to DOE's procedures, in 2008 UE filed with the DOE Part I and Part II of its application for a loan guarantee to support the potential construction and operation of a new nuclear unit. UE's loan guarantee application is not a commitment to build another nuclear unit, and there is no assurance that the DOE will provide any such guarantee to UE.

*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 renewal is pending.

**Regulatory Assets and Liabilities**

In accordance with SFAS No. 71, 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, 2008 and 2007:

| | Ameren[a] | UE | CIPS | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|
| **2008:** | | | | | | |
| Regulatory assets: | | | | | | |
| Pension and postretirement benefit costs[b][c] | $ 936 | $ 410 | $ 107 | $ 125 | $ 125 | $ 294 |
| Income taxes[c][d] | 255 | 248 | 6 | - | - | 1 |
| Asset retirement obligation[c][e] | 65 | 60 | 2 | 1 | 1 | 2 |
| Callaway costs[f] | 58 | 58 | - | - | - | - |
| Unamortized loss on reacquired debt[c][g] | 63 | 30 | 5 | 5 | 5 | 23 |
| Recoverable costs - contaminated facilities[c][h] | 97 | - | 18 | 8 | 8 | 71 |
| IP integration[i] | 33 | - | - | - | - | 33 |
| Recoverable costs - debt fair value adjustment[j] | 10 | - | - | - | - | 10 |
| Financial contracts[k] | - | - | 42 | 22 | 22 | 64 |
| Derivatives marked-to-market[l] | 118 | 16 | 27 | 25 | 25 | 50 |
| $SO_2$ emission allowances sale tracker[m] | 13 | 13 | - | - | - | - |
| FERC-ordered MISO resettlements-March 2007[n] | 12 | 12 | - | - | - | - |
| Vegetation management and infrastructure inspection cost tracker[o] | 9 | 9 | - | - | - | - |
| Storm costs[p] | 33 | 33 | - | - | - | - |
| Demand-side costs[q] | 4 | 4 | - | - | - | - |
| Reserve for workers' compensation liabilities[c][r] | 15 | 9 | 3 | - | - | 3 |
| Other[c][s] | 11 | 5 | 2 | 2 | 2 | 2 |
| Total regulatory assets | $ 1,732 | $ 907 | $ 212 | $ 188 | $ 188 | $ 553 |
| Regulatory liabilities: | | | | | | |
| Income taxes[t] | $ 180 | $ 154 | $ 14 | $ 12 | $ 12 | $ - |
| Removal costs[u] | 1,018 | 675 | 220 | 47 | 194 | 76 |
| Emission allowances[v] | 47 | 47 | - | - | - | - |
| Pension and postretirement benefit costs tracker[w] | 41 | 41 | - | - | - | - |
| MISO resettlements[x] | 5 | 5 | - | - | - | - |
| Total regulatory liabilities | $ 1,291 | $ 922 | $ 234 | $ 59 | $ 206 | $ 76 |

| | Ameren[a] | UE | CIPS | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|
| **2007:** | | | | | | |
| Regulatory assets: | | | | | | |
| Pension and postretirement benefit costs[b][c] | $ 395 | $ 161 | $ 75 | $ 19 | $ 19 | $ 140 |
| Income taxes[c][d] | 255 | 248 | 6 | - | - | 1 |
| Asset retirement obligation[c][e] | 188 | 183 | 2 | 1 | 1 | 2 |
| Callaway costs[f] | 62 | 62 | - | - | - | - |
| Unamortized loss on reacquired debt[c][g] | 59 | 28 | 4 | 5 | 5 | 22 |
| Recoverable costs - contaminated facilities[c][h] | 106 | - | 24 | 5 | 5 | 77 |
| IP integration[i] | 50 | - | - | - | - | 50 |
| Recoverable costs - debt fair value adjustment[j] | 20 | - | - | - | - | 20 |
| Derivatives marked-to-market[l] | 3 | - | 1 | - | - | 2 |
| $SO_2$ emission allowances sale tracker[m] | 7 | 7 | - | - | - | - |
| Other[c][y] | 13 | 8 | 1 | 2 | 2 | 2 |
| Total regulatory assets | $ 1,158 | $ 697 | $ 113 | $ 32 | $ 32 | $ 316 |
| Regulatory liabilities: | | | | | | |
| Income taxes[t] | $ 195 | $ 162 | $ 19 | $ 14 | $ 14 | $ - |
| Removal costs[u] | 980 | 638 | 208 | 60 | 188 | 74 |
| Emission allowances[v] | 56 | 56 | - | - | - | - |
| Pension and postretirement benefit costs tracker[w] | 8 | 8 | - | - | - | - |
| Financial contracts[k] | - | - | 38 | 18 | 18 | 55 |
| Derivatives marked-to-market[l] | 1 | 1 | - | - | - | - |
| Total regulatory liabilities | $ 1,240 | $ 865 | $ 265 | $ 92 | $ 220 | $ 129 |

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) 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. Ameren believes it is probable that these costs will be recovered through rates in future periods. See Note 11 - Retirement Benefits for additional information.
(c) These assets do not earn a return.
(d) Offset to certain deferred tax liabilities for expected recovery of future income taxes when paid. See Note 13 - Income Taxes for amortization period.
(e) 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.
(f) 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.
(g) 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.
(h) The recoverable portion of accrued environmental site liabilities, primarily collected from electric and gas customers through ICC-approved cost recovery riders in Illinois. The period of recovery will depend on the timing of actual expenditures.
(i) Reorganization costs related to the integration of IP into the Ameren system and the restructuring of IP. Pursuant to the ICC order approving Ameren's acquisition of IP, these costs are recoverable in rates through 2010.
(j) A portion of IP's unamortized debt fair value adjustment recorded upon Ameren's acquisition of IP at September 30, 2004. 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.
(k) Financial contracts entered into by the Ameren Illinois Utilities with Marketing Company, as part of the Illinois electric settlement agreement. See Illinois - Power Procurement Plan discussion above for additional information.
(l) Deferral of SFAS No. 133 natural gas-related derivative mark-to-market gains and losses.
(m) 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.
(n) 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 and will be amortized over a two-year period beginning March 1, 2009, as approved by the January 2009 MoPSC electric rate order.
(o) UE's vegetation management and infrastructure inspection costs incurred from January 1, 2008, through December 31, 2008, relating to compliance with the MoPSC vegetation management and infrastructure rules. The costs incurred between January 1, 2008, through September 30, 2008, will be amortized over three years beginning March 1, 2009, as approved by the January 2009 MoPSC electric rate order. The amortization period for the costs incurred between October 1, 2008 through December 31, 2008, will be determined in the next UE rate case.
(p) 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 a five-year period which began June 4, 2007. The 2008 storm costs are being amortized over a five-year period beginning 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 March 1, 2009, as approved by the January 2009 MoPSC electric rate order.
(q) Demand-side costs including the costs of developing, implementing and evaluating customer energy efficiency and demand response programs. These costs are being amortized over a ten-year period beginning March 1, 2009, as approved by the January 2009 MoPSC rate order.
(r) Reserve for workers' compensation liabilities. Ameren believes it is probable that these costs will be recovered through electric and gas rates in future periods.
(s) 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 the low-income weatherization and energy efficiency programs.
(t) Unamortized portion of investment tax credit and federal excess deferred taxes. See Note 13 - Income Taxes for amortization period.
(u) 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.
(v) The deferral of gains on emission allowance vintage swaps UE entered into during 2005.
(w) 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.
(x) 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.
(y) Y2K expenses being amortized over six years starting in 2002, in conjunction with the 2002 settlement of UE's Missouri electric rate case, and a DOE decommissioning assessment that was amortized over 14 years through 2007.

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.

## NOTE 3 - PROPERTY AND PLANT, NET

The following table presents property and plant, net for each of the Ameren Companies at December 31, 2008 and 2007:

| | Ameren[a] | UE | CIPS | Genco | CILCORP[b] | CILCO (Illinois Regulated) | CILCO (AERG) | IP |
|---|---|---|---|---|---|---|---|---|
| **2008:** | | | | | | | | |
| Property and plant, at original cost: | | | | | | | | |
| Electric | $ 21,244 | $ 13,214 | $ 1,744 | $ 2,451 | $ 1,348 | $ 954 | $ 948 | $ 1,840 |
| Gas | 1,505 | 347 | 365 | - | 227 | 506 | - | 565 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Other | **381** | **76** | **6** | **6** | **44** | **3** | **2** | **21** |
| | **23,130** | **13,637** | **2,115** | **2,457** | **1,619** | **1,463** | **950** | **2,426** |
| Less: Accumulated depreciation and amortization | **8,499** | **5,539** | **915** | **1,013** | **279** | **721** | **329** | **152** |
| | **14,631** | **8,098** | **1,200** | **1,444** | **1,340** | **742** | **621** | **2,274** |
| Construction work in progress: | | | | | | | | |
| Nuclear fuel in process | **190** | **190** | **-** | **-** | **-** | **-** | **-** | **-** |
| Other | **1,746** | **707** | **12** | **506** | **370** | **12** | **359** | **55** |
| Property and plant, net | **$ 16,567** | **$ 8,995** | **$ 1,212** | **$ 1,950** | **$ 1,710** | **$ 754** | **$ 980** | **$ 2,329** |
| **2007:** | | | | | | | | |
| Property and plant, at original cost: | | | | | | | | |
| Electric | $ 20,325 | $ 12,670 | $ 1,682 | $ 2,423 | $ 1,196 | $ 921 | $ 827 | $ 1,740 |
| Gas | 1,421 | 332 | 350 | - | 209 | 488 | - | 530 |
| Other | 354 | 71 | 5 | 4 | 42 | 3 | 1 | 21 |
| | 22,100 | 13,073 | 2,037 | 2,427 | 1,447 | 1,412 | 828 | 2,291 |
| Less: Accumulated depreciation and amortization | 8,196 | 5,437 | 878 | 972 | 231 | 697 | 329 | 111 |
| | 13,904 | 7,636 | 1,159 | 1,455 | 1,216 | 715 | 499 | 2,180 |
| Construction work in progress: | | | | | | | | |
| Nuclear fuel in process | 103 | 103 | - | - | - | - | - | - |
| Other | 1,062 | 450 | 15 | 228 | 278 | 22 | 256 | 40 |
| Property and plant, net | $ 15,069 | $ 8,189 | $ 1,174 | $ 1,683 | $ 1,494 | $ 737 | $ 755 | $ 2,220 |

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries as well as intercompany eliminations.
(b) Includes CILCO (Illinois Regulated) and CILCO (AERG) with adjustments due to purchase accounting.

In March 2006, following the receipt of all required regulatory approvals, UE completed the purchase of a 640-megawatt CT facility located in Audrain County, Missouri, at a price of $115 million from NRG Audrain Holding LLC, and NRG Audrain Generating LLC, both affiliates of NRG Energy Inc. (collectively, NRG). As a part of this transaction, UE was assigned the rights of NRG as lessee of the CT facility under a long-term lease with Audrain County, and UE assumed NRG's obligations under the lease. The lease will expire on December 1, 2023.

Also in March 2006, following the receipt of all required regulatory approvals, UE completed the purchase from subsidiaries of Aquila Inc., of the 510-megawatt Goose Creek CT facility in Piatt County, Illinois, at a price of $106 million, and the 340-megawatt Raccoon Creek CT facility located in Clay County, Illinois, at a price of $71 million.

The following table provides accrued capital expenditures at December 31, 2008, 2007 and 2006, which represent noncash investing activity excluded from the statements of cash flows:

| | **Ameren[a]** | **UE** | **CIPS** | **Genco** | **CILCORP** | **CILCO** | **IP** |
|---|---|---|---|---|---|---|---|
| **2008:** | | | | | | | |
| Accrued capital expenditures | **$ 213** | **$ 110** | **$ 3** | **$ 41** | **$ 45** | **$ 45** | **$ 14** |
| **2007:** | | | | | | | |
| Accrued capital expenditures | $ 153 | $ 76 | $ 3 | $ 28 | $ 35 | $ 35 | $ 7 |
| **2006:** | | | | | | | |
| Accrued capital expenditures | $ 159 | $ 92 | $ 5 | $ 22 | $ 15 | $ 15 | $ 20 |

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

## NOTE 4 - SHORT-TERM BORROWINGS AND LIQUIDITY

The liquidity needs of the Ameren Companies are typically supported through the use of available cash and 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, 2008 and 2007, respectively, and excludes letters of credit issued under this credit facility:

| | **Ameren (Parent)** | **UE** | **Genco** | **Total** |
|---|---|---|---|---|
| **2008:** | | | | |
| Average daily borrowings outstanding during 2008 | **$ 389** | **$ 154** | **$ 41** | **$ 584** |
| Outstanding short-term debt at period end | **275** | **251** | **-** | **526** |

| | | | | |
|---|---|---|---|---|
| Weighted-average interest rate during 2008 | **3.58%** | **3.25%** | **3.97%** | **3.52%** |
| Peak short-term borrowings during 2008 | **$ 675** | **$ 493** | **$ 150** | **$ 1,068** |
| Peak interest rate during 2008 | **7.25%** | **5.65%** | **5.53%** | **7.25%** |
| **2007:** | | | | |
| Average daily borrowings outstanding during 2007 | $ 198 | $ 292 | $ 22 | $ 512 |
| Outstanding short-term debt at period end | 550 | 82[a] | 100 | 732[a] |
| Weighted-average interest rate during 2007 | 5.75% | 5.66% | 5.43% | 5.68% |
| Peak short-term borrowings during 2007 | $ 550 | $ 506 | $ 100 | $ 856 |
| Peak interest rate during 2007 | 8.25% | 8.25% | 5.76% | 8.25% |

(a) Includes issuances under commercial paper programs of $80 million at Ameren and UE supported by this facility as of December 31, 2007.

The following table summarizes the borrowing activity and relevant interest rates under the 2007 $500 million credit facility described below for the years ended December 31, 2008 and 2007:

| | CIPS | CILCORP (Parent) | CILCO (Parent) | IP | AERG | Total |
|---|---|---|---|---|---|---|
| **2008:** | | | | | | |
| Average daily borrowings outstanding during 2008 | **$ -** | **$ 100** | **$ 56** | **$ 133** | **$ 95** | **$ 384** |
| Outstanding short-term debt at period end | **-** | **-** | **-** | **-** | **85** | **85** |
| Weighted-average interest rate during 2008 | **-** | **4.62%** | **4.02%** | **4.28%** | **3.95%** | **4.25%** |
| Peak short-term borrowings during 2008 | **$ -** | **$ 125** | **$ 75** | **$ 200** | **$ 150** | **$ 500** |
| Peak interest rate during 2008 | **-** | **6.66%** | **6.47%** | **6.15%** | **6.22%** | **6.66%** |
| **2007:** | | | | | | |
| Average daily borrowings outstanding during 2007 | $ - | $ 105 | $ 36 | $ 134 | $ 80 | $ 355 |
| Outstanding short-term debt at period end | - | 125 | 75 | 175 | 65 | 440 |
| Weighted-average interest rate during 2007 | - | 6.94% | 6.43% | 6.59% | 6.86% | 6.74% |
| Peak short-term borrowings during 2007 | $ - | $ 125 | $ 75 | $ 200 | $ 100 | $ 500 |
| Peak interest rate during 2007 | - | 8.63% | 6.47% | 6.64% | 7.02% | 8.63% |

The following table summarizes the borrowing activity and relevant interest rates under the 2006 $500 million credit facility described below for the years ended December 31, 2008 and 2007, respectively:

| | CIPS | CILCORP (Parent) | CILCO (Parent) | IP | AERG | Total |
|---|---|---|---|---|---|---|
| **2008:** | | | | | | |
| Average daily borrowings outstanding during 2008 | **$ 58** | **$ 50** | **$ 37** | **$ 27** | **$ 151** | **$ 323** |
| Outstanding short-term debt at period end | **62** | **50** | **-** | **-** | **151** | **263** |
| Weighted-average interest rate during 2008 | **4.21%** | **4.50%** | **3.78%** | **4.08%** | **3.94%** | **4.07%** |
| Peak short-term borrowings during 2008 | **$ 135** | **$ 50** | **$ 75** | **$ 150** | **$ 200** | **$ 465** |
| Peak interest rate during 2008 | **6.31%** | **7.01%** | **5.98%** | **6.50%** | **7.01%** | **7.01%** |
| **2007:** | | | | | | |
| Average daily borrowings outstanding during 2007 | $ 98 | $ 49 | $ 63 | $ 63 | $ 107 | $ 380 |
| Outstanding short-term debt at period end | 125 | 50 | 40 | - | 165 | 380 |
| Weighted-average interest rate during 2007 | 6.52% | 6.89% | 6.35% | 6.56% | 6.84% | 6.63% |
| Peak short-term borrowings during 2007 | $ 135 | $ 50 | $ 100 | $ 125 | $ 200 | $ 500 |
| Peak interest rate during 2007 | 8.25% | 7.04% | 6.47% | 6.64% | 8.25% | 8.25% |

At December 31, 2008, Ameren and certain of its subsidiaries had $2.15 billion of committed credit facilities, consisting of the three facilities shown above, in the amounts of $1.15 billion, $500 million, and $500 million, maturing in July 2010, January 2010, and January 2010, respectively.

Ameren can directly borrow under the $1.15 billion facility, as amended, up to the entire amount of the facility. UE can directly borrow under this facility up to $500 million on a 364-day basis. Genco can directly borrow under this facility up to $150 million on a 364-day basis. The amended facility will terminate on July 14, 2010, with respect to all borrowers. The termination date for UE and Genco is July 9, 2009, subject to the annual 364-day renewal provisions of the facility.

Under the $1.15 billion credit facility, the principal amount of each revolving loan will be due and payable no later than the final maturity of the facility in the case of Ameren and the last day of the then-applicable 364-day period in the case of UE and Genco. Swingline loans will be made on same-day notice and will mature five business days after they are made.

Ameren, UE and Genco will use the proceeds of any borrowings under the facility for general corporate purposes. These purposes include

working capital and funding loans under the Ameren money pool arrangements.

The $1.15 billion credit facility may be used to support the commercial paper programs of Ameren and UE. However, Ameren and UE are currently limited in their access to the commercial paper market as a result of downgrades in their short-term credit ratings. Access to the $1.15 billion credit facility, the 2006 $500 million credit facility, and the 2007 $500 million credit facility for the Ameren Companies is subject to reduction as borrowings are made by affiliates.

CIPS, CILCORP, CILCO, IP and AERG are parties to the 2007 $500 million credit facility and to the 2006 $500 million credit facility.

The obligations of each borrower under the 2006 $500 million credit facility and the 2007 $500 million credit facility are several and not joint, and are not guaranteed by Ameren or any other subsidiary of Ameren. The maximum amount available to each borrower under the 2006 $500 million credit facility, including for issuance of letters of credit on its behalf, is limited as follows: CIPS - $135 million, CILCORP - $50 million, CILCO - $75 million, IP - $150 million and AERG - $200 million. Each of the companies has drawn various loans under this credit facility. Under the 2007 $500 million credit facility, the maximum amount available to each borrower, including for issuance of letters of credit on its behalf, is limited as follows: CILCORP - $125 million, CILCO - $75 million, IP - $200 million and AERG - $100 million. CIPS and CILCO have the option of permanently reducing their borrowing authority under the 2006 $500 million credit facility and shifting, in one or more transactions, such capacity to the 2007 $500 million credit facility up to the same limits. The total borrowing authority of CIPS and CILCO under the 2006 $500 million credit facility and the 2007 $500 million credit facility cannot at any time exceed $135 million and $150 million, respectively, in the aggregate. Until either CIPS or CILCO elects to increase its borrowing capacity under the 2007 $500 million credit facility and issue first mortgage bonds as security for its obligations thereunder, as described below, it will not be considered a borrower under the 2007 $500 million credit facility and will not be subject to the covenants thereof (except as a subsidiary of a borrower). The borrowing companies will use the proceeds of any borrowings for working capital and other general corporate purposes. However, a portion of the borrowings by AERG may be limited to financing or refinancing the development, management and operation of any of its projects or assets. The 2006 and 2007 $500 million credit facilities will terminate on January 14, 2010.

The obligations of CIPS, CILCO and IP under the 2006 $500 million facility are secured by the issuance of first mortgage bonds by each such utility under its respective mortgage indenture in the amounts of $135 million, $75 million, and $150 million, respectively. The obligations of CILCO and IP under the 2007 $500 million credit facility are secured by the issuance of first mortgage bonds in the amounts of $75 million and $200 million, respectively. If either CIPS or CILCO elects to transfer borrowing authority from the 2006 $500 million credit facility to the 2007 $500 million credit facility, it must retire an appropriate amount of first mortgage bonds issued with respect to the 2006 $500 million credit facility and issue new bonds in an equal amount to secure its obligations under the 2007 $500 million credit facility. In July 2007, CILCO permanently reduced its $150 million of borrowing authority under the 2006 $500 million credit facility by $75 million and shifted that amount of capacity to the 2007 $500 million credit facility. CILCO is now considered a borrower under both credit facilities and is subject to the covenants of both. The obligations of CILCORP under both the 2006 $500 million credit facility and the 2007 $500 million credit facility are secured by a pledge of the common stock of CILCO. The obligations of AERG under both the 2006 $500 million credit facility and the 2007 $500 million credit facility are secured by a mortgage and security interest in its E.D. Edwards and Duck Creek power plants and related licenses, permits, and similar rights.

On September 15, 2008, Lehman filed for protection under Chapter 11 of the federal Bankruptcy Code in the U.S. Bankruptcy Court in the Southern District of New York. As of December 31, 2008, Lehman Brothers Bank, FSB, a subsidiary of Lehman, had lending commitments of $100 million and $21 million under the $1.15 billion credit facility and the 2006 $500 million credit facility, respectively. Assuming Lehman Brothers Bank, FSB does not fund its pro-rata share of funding or letter of credit issuance requests under these two facilities, and such participations are not assigned or otherwise transferred to other lenders, total amounts accessible by the Ameren Companies and AERG will be limited to amounts not less than $1.05 billion under the $1.15 billion credit facility and $479 million under the 2006 $500 million credit facility.

Based on outstanding borrowings under the $1.15 billion credit facility and the 2007 and 2006 $500 million credit facilities (including reductions for $9 million of letters of credit issued under the $1.15 billion credit facility and unfunded Lehman participations under the $1.15 billion credit facility and the 2006 $500 million credit facility), the available amounts under the facilities at December 31, 2008, were $540 million, $415 million, and $220 million, respectively.

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. If Ameren issues capital stock or other equity interests (except for director or employee benefit or dividend reinvestment plan purposes), or certain equity-like hybrid securities, or certain additional indebtedness in amounts exceeding $25 million, Ameren is required under the term loan agreement to use the resulting net proceeds to prepay amounts borrowed under the agreement. The lenders under the term loan agreement have waived this prepayment requirement to the extent that the net proceeds from the issuance of certain funded indebtedness are applied to repurchase or to

redeem indebtedness of CILCORP. Additionally, if Ameren replaces its $1.15 billion credit facility with one or more credit facilities having a total available commitment in excess of $1.15 billion, Ameren is required under the term loan agreement to prepay amounts borrowed thereunder in an amount equal to the excess of the new commitments over $1.15 billion. Such mandatory prepayments are without premium or penalty (except for any funding indemnity due in respect of Eurodollar loans).

Borrowings under the $300 million term loan agreement will bear interest, at the election of Ameren, at (1) a Eurodollar rate plus a margin, which margin is subject to a floor of 0.90% per annum and a cap of 1.50% per annum, or (2) a rate equal to the higher of the prime rate or the federal funds effective rate plus 0.50% per year. Ameren used the proceeds borrowed under the term loan agreement to reduce amounts borrowed under the $1.15 billion credit facility, which thereby made additional amounts available for borrowing under that credit facility. The average annual interest rate for borrowing under the $300 million term loan agreement was 3.93% from its inception through December 31, 2008. The obligations of Ameren under the term loan agreement are unsecured. No subsidiary of Ameren is a party to, guarantor of, or borrower under the term loan agreement.

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. Borrowings under the $20 million term loan agreement will bear interest, at the election of Ameren, at (1) a rate equal to the applicable LIBOR rate plus 1.70% per annum, or (2) a rate equal to the highest of the prime rate, the federal funds effective rate plus 0.50% per annum and the applicable LIBOR rate plus 2.00% per annum. The obligations of Ameren under the $20 million term loan agreement are unsecured. No subsidiary of Ameren is a party to, guarantor of, or borrower under the agreement.

**Indebtedness Provisions and Other Covenants**

The Ameren Companies' bank credit facilities contain provisions that, among other things, place restrictions on their ability to incur liens, sell assets, and merge with other entities. The $1.15 billion credit facility contains provisions that limit total indebtedness of each of Ameren, UE and Genco to 65% of total consolidated capitalization pursuant to a calculation defined in the facility. Exceeding these debt levels would result in a default under the $1.15 billion credit facility.

The $1.15 billion credit facility also contains provisions for default, including cross-defaults, with respect to a borrower. Defaults can result from an event of default under any other facility covering indebtedness of that borrower or certain of its subsidiaries in excess of $50 million in the aggregate. The obligations of Ameren, UE and Genco under the facility are several and not joint, and except under limited circumstances, the obligations of UE and Genco are not guaranteed by Ameren or any other subsidiary. CIPS, CILCORP, CILCO, IP and AERG are not considered subsidiaries for purposes of the cross-default or other provisions.

Under the $1.15 billion credit facility, restrictions apply limiting investments in and other transfers to CIPS, CILCORP, CILCO, IP, AERG and their subsidiaries by Ameren and certain subsidiaries. Additionally, CIPS, CILCORP, CILCO, IP, AERG and their subsidiaries are excluded for purposes of determining compliance with the 65% total consolidated indebtedness to total consolidated capitalization financial covenant in the facility.

Both the 2007 $500 million credit facility and the 2006 $500 million credit facility entered into by CIPS, CILCORP, CILCO, IP and AERG limit the indebtedness of each borrower to 65% of consolidated total capitalization pursuant to a calculation set forth in the facilities. Events of default under these facilities apply separately to each borrower (and, except in the case of CILCORP, to their subsidiaries). An event of default under these facilities does not constitute an event of default under the $1.15 billion credit facility, or vice versa. In addition, if CIPS', CILCO's or IP's senior secured long-term debt securities or first mortgage bonds, or CILCORP's senior unsecured long-term debt securities, should receive a below-investment-grade credit rating from either Moody's or S&P, then each such borrower will be limited to common and preferred stock dividend payments of $10 million per year while such below-investment-grade credit rating is in effect. On July 26, 2006, Moody's downgraded CILCORP's senior unsecured long-term debt credit rating to below-investment-grade, causing it to be subject to this dividend payment limitation. No similar restriction applies to AERG, which is currently not rated by Moody's or S&P, if its debt-to-operating- cash-flow ratio, as set forth in these facilities, is less than or equal to a 3.0 to 1.0 ratio. As of December 31, 2008, AERG failed to meet the debt-to-operating-cash-flow ratio test in the 2007 and 2006 $500 million credit facilities. AERG's ability to pay dividends is therefore currently limited to a maximum of $10 million per fiscal year. CIPS, CILCO and IP are not currently limited in their dividend payments by this provision of the 2007 $500 million or 2006 $500 million credit facilities. Ameren's access to dividends from CILCO and AERG is currently limited by dividend restrictions at CILCORP.

The 2007 $500 million credit facility and the 2006 $500 million credit facility also limit the amount of other secured indebtedness issuable by each borrower. For CIPS, CILCO and IP, other secured debt is limited to that permitted under their respective mortgage indentures. For CILCORP, other debt secured by the pledge of CILCO common stock is limited (1) under the 2007 $500 million credit facility to $425 million (in addition to the principal amount of CILCORP's outstanding senior notes and senior bonds and its obligations under the 2006 $500 million credit facility) and (2)

under the 2006 $500 million credit facility to $500 million (including the principal amount of CILCORP's outstanding senior notes and senior bonds and amounts drawn on the 2007 $500 million credit facility). For AERG, other debt secured on an equal basis with its obligations under the facilities is limited to $100 million by the 2007 $500 million credit facility (excluding amounts drawn by AERG under the 2006 $500 million credit facility) and $200 million by the 2006 $500 million credit facility. The limitations on other secured debt at CILCORP and AERG in the 2007 $500 million credit facility are subject to adjustment based on the borrowing sublimits of these entities under this facility or under the 2006 $500 million credit facility. In addition, the 2007 $500 million credit facility and the 2006 $500 million credit facility prohibit CILCO from issuing any preferred stock if, after such issuance, the aggregate liquidation value of all CILCO preferred stock issued after February 9, 2007, and July 14, 2006, respectively, would exceed $50 million.

Under the 2007 $500 million and 2006 $500 million credit facilities, each of CIPS, CILCO and IP was originally required to reserve future bonding capacity under its respective mortgage indentures (that is, it agreed to forgo the issuance of additional mortgage bonds otherwise permitted under the terms of each mortgage indenture). On March 26, 2008, CIPS, CILCO and IP and other parties to the credit facilities entered into amendments to the credit facilities, that eliminated this requirement.

The $300 million term loan agreement entered into in June 2008 has terms similar to the $1.15 billion credit facility, except that amounts repaid under the term loan agreement may not be reborrowed. The term loan agreement also contains nonfinancial covenants, including restrictions on the ability to incur liens, dispose of assets, and merge with other entities. In addition, the term loan agreement has nonfinancial covenants to limit the ability of Ameren to invest in or transfer assets to other entities, including affiliates. The events of default under the term loan agreement, including a cross-default to the occurrence of an event of default under the $1.15 billion credit facility or any other agreement covering indebtedness of Ameren and its subsidiaries in excess of $25 million in the aggregate, are similar to those contained in the $1.15 billion credit facility. Each of CIPS, CILCORP, CILCO, IP, AERG and each of their subsidiaries is excluded from the definition of "subsidiary" under the term loan agreement and accordingly is not subject to certain of the covenants, representations, or warranties under the term loan agreement. The term loan agreement requires Ameren to maintain consolidated indebtedness of not more then 65% of consolidated total capitalization pursuant to a calculation defined in the term loan agreement.

Under the $20 million term loan agreement entered into in January 2009, Ameren may elect, for up to three 30-day periods, to pay down and reduce to zero the outstanding principal balance. The term loan agreement also contains nonfinancial covenants, including restrictions on the ability to incur liens, dispose of assets, and merge with other entities. In addition, the term loan agreement has nonfinancial covenants to limit the ability of Ameren to invest in or transfer assets to other entities, including affiliates. The events of default under the term loan agreement, including a cross-default to the occurrence of an event of default under the $1.15 billion credit facility or any other agreement covering indebtedness of Ameren and its subsidiaries in excess of $50 million in the aggregate, are similar to those contained in the $1.15 billion credit facility. Each of CIPS, CILCORP, CILCO, IP, AERG and each of their subsidiaries is excluded from the definition of "subsidiary" under the term loan agreement and accordingly is not subject to certain of the covenants, representations, or warranties under the agreement. The term loan agreement requires Ameren to maintain a consolidated capitalization ratio of not more than 65% pursuant to a calculation defined in the agreement.

As of December 31, 2008, the ratios of total indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the $1.15 billion credit facility for Ameren, UE and Genco were 54%, 51% and 53%, respectively. The ratios for CIPS, CILCORP, CILCO, IP and AERG, calculated in accordance with the provisions of the 2006 $500 million credit facility and the 2007 $500 million credit facility, were 51%, 60%, 48%, 53% and 45%, respectively. The ratio for Ameren calculated in accordance with the provisions of the $300 million term loan agreement was 54%.

None of Ameren's credit facilities or financing arrangements contain credit rating triggers that would cause an event of default or acceleration of repayment of outstanding balances. At December 31, 2008, 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 is the 2006 $500 million and the 2007 $500 million credit facilities. 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, 2008, was 2.85% (2007 - 5.80%).

*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 Ameren's $1.15 billion credit facility through a non-state-regulated subsidiary money pool agreement. The total amount available to the pool participants at any time is reduced by borrowings from Ameren made by its subsidiaries and 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 $1.15 billion credit facility at December 31, 2008. 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, 2008 was 3.51% (2007 - 5.14%).

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, 2008, 2007, and 2006.

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 short-term 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 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, 2008 and 2007:

| | 2008 | 2007 |
|---|---|---|
| **UE:** | | |
| First mortgage bonds:[a] | | |
| 6.75% Series due 2008 | $ - | $ 148 |
| 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 | - |
| 5.10% Senior secured notes due 2018[b] | 200 | 200 |
| 6.70% Senior secured notes due 2019[b] | 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 |
| Environmental improvement and pollution control revenue bonds: [a][b][c][d] | | |
| 1991 Series due 2020 | **-** | 43 |
| 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 |
| 2000 Series A due 2035 | **-** | 64 |
| 2000 Series B due 2035 | **-** | 63 |
| 2000 Series C due 2035 | **-** | 60 |
| 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) | **82** | 86 |
| Audrain County capital lease (Audrain County CT) | **240** | 240 |
| Total long-term debt, gross | **3,684** | 3,366 |
| Less: Unamortized discount and premium | **(7)** | (6) |
| Less: Maturities due within one year | **(4)** | (152) |
| Long-term debt, net | **$ 3,673** | $ 3,208 |
| **CIPS:** | | |
| First mortgage bonds:[a] | | |
| 5.375% Senior secured notes due 2008[b] | **$ -** | $ 15 |
| 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: | | |
| 2004 Series due 2025[a][b][c][d] | **-** | 35 |
| 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** | 472 |
| Less: Unamortized discount and premium | **(1)** | (1) |
| Less: Maturities due within one year | **-** | (15) |
| Long-term debt, net | **$ 421** | $ 456 |
| | **2008** | **2007** |
| **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** | - |
| Total long-term debt, gross | **775** | 475 |
| Less: Unamortized discount and premium | **(1)** | (1) |
| Long-term debt, net | **$ 774** | $ 474 |
| **CILCORP (Parent):[f]** | | |
| Unsecured notes: | | |
| 8.70% Senior notes due 2009[g] | **$ 124** | $ 124 |
| 9.375% Senior bonds due 2029[g] | **210** | 210 |
| Fair-market value adjustments | **49** | 55 |
| Total long-term debt, gross | **383** | 389 |
| Less: Maturities due within one year | **(126)** | - |
| Long-term debt, net | **$ 257** | $ 389 |
| **CILCO:** | | |
| First mortgage bonds:[a] | | |
| 8.875% Senior secured notes due 2013[b] | **$ 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] | | |

| | | |
|---|---|---|
| Series 2004 due 2039[b][d] | - | 19 |
| 6.20% Series 1992B due 2012 | 1 | 1 |
| 5.90% Series 1993 due 2023 | 32 | 32 |
| Total long-term debt, gross | 279 | 148 |
| Less: Maturities due within one year | - | - |
| Long-term debt, net | $ 279 | $ 148 |
| CILCORP consolidated long-term debt, net | $ 536 | $ 537 |
| **IP**: | | |
| Mortgage bonds:[a] | | |
| 7.50% Series due 2009 | $ 250 | $ 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 | - |
| 9.750% Senior secured notes due 2018[b] | 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 |
| 1997 Series A, B and C due 2032[d] | - | 150 |
| Series 2001 Non-AMT due 2028[d] | - | 112 |
| Series 2001 AMT due 2017[d] | - | 75 |
| Fair-market value adjustments | 10 | 18 |
| Total long-term debt, gross | 1,410 | 1,018 |
| Less: Unamortized discount and premium | (10) | (4) |
| Less: Maturities due within one year | (250) | - |
| Long-term debt, net | $ 1,150 | $ 1,014 |
| Long-term debt payable to IP SPT: | | |
| 5.65% due 2008 A-7 | $ - | $ 86 |
| Less: Overfunded amount | - | (32) |
| Fair-market value adjustments | - | 2 |
| Total long-term debt payable to IP SPT | - | 56 |
| Less: Maturities due within one year | - | (56) |
| Long-term debt payable to IP SPT, net | $ - | $ - |
| Ameren consolidated long-term debt, net | $ 6,554 | $ 5,689 |

(a) At December 31, 2008, 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 102% of par, declining to 101% of par in October 2009 and 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 103.04% of par declining annually thereafter to 100% of par in June 2012) which, pursuant to a covenant contained in the 6.70% Series due 2036, may not be called in full prior to June 15, 2009; 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 - 7.50% Series due 2009, 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, 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 2008 and 2007 were as follows:

| | 2008 | 2007 | | 2008 | 2007 |
|---|---|---|---|---|---|
| UE 1991 Series | Retired | 3.66% | CIPS Series 2004 | Retired | 3.68% |
| UE 1992 Series | 3.66% | 3.72% | CIPS 1993 Series B-1 | 1.98% | 3.25% |
| UE 1998 Series A | 3.97% | 3.69% | CILCO Series 2004 | Retired | 3.68% |
| UE 1998 Series B | 3.71% | 3.66% | IP 1997 Series A | Retired | 3.93% |
| UE 1998 Series C | 4.06% | 3.66% | IP 1997 Series B | Retired | 3.89% |
| UE 2000 Series A | Retired | 3.55% | IP 1997 Series C | Retired | 3.84% |
| UE 2000 Series B | Retired | 3.55% | IP Series 2001 (AMT) | Retired | 3.89% |
| UE 2000 Series C | Retired | 3.56% | IP Series 2001 (Non-AMT) | Retired | 3.69% |

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

(f) CILCORP's long-term debt is secured by a pledge of the common stock of CILCO.

(g) These notes are subject to a revocable tender offer whereby holders may receive up to $1,057.50 and $1,230, respectively, for each $1,000 principal amount of 8.70% senior notes due 2009 and 9.375% senior bonds due 2029 tendered.

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

31, 2008:

| | UE | CIPS | Genco | CILCORP (Parent) | CILCO | IP | Ameren Consolidated |
|---|---|---|---|---|---|---|---|
| 2009 | $ 4 | $ - | $ - | $ 126[a] | $ - | $ 250 | $ 380 |
| 2010 | 4 | - | 200 | - | - | - | 204 |
| 2011 | 4 | 150 | - | - | - | - | 154 |
| 2012 | 178 | - | - | - | 1 | - | 179 |
| 2013 | 205 | - | - | - | 150 | - | 355 |
| Thereafter | 3,289 | 272 | 575 | 210 | 128 | 1,150 | 5,624 |
| Total | $ 3,684[b] | $ 422[b] | $ 775[b] | $ 336[c] | $ 279 | $ 1,400[b][d] | $ 6,896 |

(a) Includes $2 million of fair-market value adjustments related to CILCORP's current maturities of long-term debt.
(b) Excludes unamortized discount and premium of $7 million, $1 million, $1 million, and $10 million at UE, CIPS, Genco, and IP, respectively.
(c) Excludes $47 million related to CILCORP's long-term debt fair-market value adjustments.
(d) Excludes $10 million related to IP's long-term debt fair-market value adjustments.

All of the Ameren Companies expect to fund maturities of long-term debt, short-term debt and contractual obligations through a combination of cash flow from operations and external financing. See Note 4 - Short-term Borrowings and Liquidity for a discussion of external financing availability.

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, 2008:

| | Effective Date | Authorized Amount |
|---|---|---|
| Ameren[a] | November 2008 | Not limited |
| UE[b] | June 2008 | Not limited |
| CIPS[a] | November 2008 | Not limited |
| Genco[a] | November 2008 | Not limited |
| CILCO[a] | November 2008 | Not limited |
| IP[a] | November 2008 | Not limited |

(a) In November 2008, Ameren, as a well-known seasoned issuer, along with 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.
(b) In June 2008, UE, as a well-known seasoned issuer, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in June 2011.

**Ameren**

Ameren's acquisitions of CILCORP and IP resulted in fair value adjustments to long-term debt of $111 million and $195 million, respectively. The fair value adjustments are being amortized to interest expense over the remaining life or to the expected redemption date of each debt issuance. As of December 31, 2008, the remaining unamortized balance of the fair-market value adjustments for CILCORP and IP were $49 million and $10 million, respectively. At IP, the amortization of fair value adjustments is offset in interest expense by a related amortization of a regulatory asset. See Note 2 - Rate and Regulatory Matters for more information on the regulatory asset.

The following table presents the amortization of the CILCORP and IP fair value adjustments for the succeeding five years:

| | CILCORP | IP |
|---|---|---|
| 2009 | $ 5 | $ 5 |
| 2010 | 2 | (a) |
| 2011 | 2 | (a) |
| 2012 | 2 | (a) |
| 2013 | 2 | (a) |
| Thereafter | 36 | 4 |

(a) Amount is less than $1 million.

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 (including a subsidiary plan that has now been merged into the Ameren 401(k) plan), Ameren issued 4.0 million, 1.7 million, and 1.9 million shares of common stock in 2008, 2007, and 2006, respectively, which were valued at $154 million, $91 million, and $96 million for the respective years.

In February 2007, $100 million of Ameren's 5.70% notes matured and were retired.

In May 2007, $250 million of Ameren's senior notes matured and were retired.

**UE**

In June 2007, UE issued $425 million of 6.40% senior secured notes due June 15, 2017, with interest payable semi-annually on June 15 and December 15 of each year, beginning in December 2007. These notes are secured by first mortgage bonds. UE received net proceeds of $421 million, which were used to repay short-term debt.

In connection with UE's June 2007 issuance of $425 million of senior secured notes, UE agreed, that so long as those senior secured notes are outstanding, it will not, prior to June 15, 2012, optionally redeem, purchase or otherwise retire in full its outstanding first mortgage bonds not subject to release provisions, thus causing a first mortgage bond release date to occur. Such 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 ranking equally with any other outstanding senior unsecured indebtedness of UE. UE further agreed that the interest rate for these $425 million of senior secured notes will be subject to an increase of up to a maximum of 2.00% if such release date occurs between June 15, 2012, and June 15, 2017 (the maturity date of the $425 million senior secured notes), and if Moody's or S&P downgrades the rating assigned to these senior secured notes below investment grade as a result of the release within 30 days of such release (subject to extension if and for so long as the rating for such senior secured notes is under consideration for possible downgrade).

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 will 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 will 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 is used to fund capital expenditures, to repay short-term debt, and for general corporate purposes. Genco exchanged the outstanding unregistered unsecured notes for registered unsecured notes in July 2008.

**CILCORP**

As discussed above, in conjunction with Ameren's acquisition of CILCORP, CILCORP's long-term debt was increased to fair value by $111 million. Amortization related to fair-value adjustments was $6 million, $6 million, and $6 million for the years ended December 31, 2008, 2007, and 2006, respectively, and costs related to repayments were $- million, $- million , and $2 million for the years ended December 31, 2008, 2007, and 2006, respectively. These amounts were included in interest expense in the Consolidated Statements of Income of Ameren and CILCORP.

See Note 4 - Short-term Borrowings and Liquidity regarding CILCORP's pledge of the common stock of CILCO as security for its obligations under the 2006 $500 million credit facility and the 2007 $500 million credit facility.

In September 2008, CILCORP commenced a cash tender offer for any and all of its outstanding 8.70% senior notes due 2009 ($123.755 million aggregate principal amount) and its 9.375% senior bonds due 2029 ($210.565 million aggregate principal amount), collectively, the "notes." Concurrent with the tender offer, CILCORP solicited consents from the holders of the notes to certain proposed amendments to the indenture governing these securities. Any holder tendering securities as part of this offer is deemed to consent to the proposed amendments. No consents will be accepted separate from a tender of such holder's securities. The amendments would eliminate certain restrictive covenants in the indenture and the notes. The total consideration for each $1,000 principal amount of 2009 notes validly tendered on or prior to the current consent and expiration date, which has been extended to April 30, 2009, is $1,057.50. The total consideration includes a consent payment of $40 per $1,000 principal amount of such 2009 notes tendered on or prior to such date. The total consideration for each $1,000 principal amount of 2029 bonds validly tendered on or prior to the current April 30, 2009, consent and expiration date is $1,230, which includes a consent payment of $50 per $1,000 principal amount of such 2029 bonds tendered on or prior to such date. Holders validly tendering and not withdrawing notes on or before the extended consent and expiration date are eligible to receive the applicable total consideration. In addition, tenders of notes, including previously tendered notes, may be withdrawn (and related consents may be rescinded) at any time prior to April 30, 2009. As of January 28, 2009, CILCORP had received consents, net of those rescinded, from the holders of $121.3 million, or 98.0%, of its outstanding 2009 8.70% senior notes and $206.6 million, or 98.1%, of its outstanding 2029 bonds. Consummation of the tender offer and the consent solicitation is subject to a number of conditions, including the absence of certain adverse legal and market developments, as described in the offer to purchase. CILCORP has reserved the right to amend, further extend, terminate, or waive any conditions to the tender offer and the consent solicitation at any time. The impact on CILCORP's net income of the tender offer is expected to be approximately $3 million, if consummated.

**CILCO**

In July 2007, CILCO redeemed 11,000 shares of its 5.85% Class A preferred stock at a redemption price of $100 per share plus accrued and unpaid dividends. The redemption satisfied CILCO's mandatory sinking fund redemption requirement for this series of preferred stock for 2007.

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 debt. 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 will 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**

As discussed above, in conjunction with Ameren's acquisition of IP, IP's long-term debt was increased to fair value by $195 million. Amortization related to fair value adjustments was $13 million for the year ended December 31, 2006, and was included in interest expense in the consolidated statements of income of Ameren and IP. Beginning in 2007, the amortization related to fair value adjustments was recoverable in rates and a regulatory asset was established. See Note 2 - Rate and Regulatory Matters for more information.

In November 2007, IP issued and sold, with registration rights in a private placement, $250 million of 6.125% senior secured notes due November 15, 2017, with interest payable semiannually on May 15 and November 15 of each year, beginning in May 2008. These notes are secured by mortgage bonds, which are subject to fallaway provisions as defined in the related financing agreements. IP received net proceeds of $248 million, which were used to repay short-term debt. IP exchanged the outstanding unregistered secured notes for registered secured notes in April 2008.

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 will 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, as allowed under the Illinois Electric Utility Transition Funding Law.

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 will 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.

**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 the issuances of first mortgage bonds and preferred stock. UE, CIPS, CILCO and IP are required to meet certain ratios to issue first mortgage bonds and preferred stock. 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, 2008, 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 | 3.0 | $ 1,102 | ≥2.5 | 40.4 | $ 1,126 |
| CIPS | ≥2.0 | 2.1 | 33 | ≥1.5 | 1.4 | - |
| CILCO | ≥2.0[d] | 13.5 | 181 | ≥2.5 | 51.4 | 331[e] |
| IP | ≥2.0 | 2.0 | 296 | ≥1.5 | 1.0 | - |

(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 meeting required coverage ratios or unfunded property additions, whichever is more restrictive. The amounts shown also include bonds issuable based on retired bond capacity of $161 million, $18 million, $44 million and $286 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, 2008, CILCO had earnings equivalent to at least 31% of the principal amount of all mortgage bonds outstanding.

(e) See Note 4 - Short-term Borrowings and Liquidity for a discussion regarding a restriction on the issuance of preferred stock by CILCO under the 2006 $500 million credit facility and the 2007 $500 million credit facility.

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, 2008.

CILCO's articles of incorporation contain certain provisions that prohibit the payment of dividends on its common stock (1) from either paid-in surplus or any surplus created by a reduction of stated capital or capital stock, or (2) if at the time of dividend declaration, there shall not remain to the credit of earned surplus account (after deducting the amount of such dividends) an amount at least equal to two times the annual dividend requirement on all outstanding shares of CILCO's preferred stock.

Genco's and CILCORP's indentures include provisions that require the companies to maintain certain debt service coverage and/or debt-to-capital ratios in order for the companies 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, 2008:

| | Required Interest Coverage Ratio | Actual Interest Coverage Ratio | Required Debt-to-Capital Ratio | Actual Debt-to-Capital Ratio |
|---|---|---|---|---|
| Genco [(a)] | ≥1.75[(b)] | 6.9 | ≤60% | 51% |
| CILCORP[(c)] | ≥2.2 | 3.8 | ≤67% | 32% |

(a) Interest coverage ratio relates to covenants regarding 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 most recently ended four fiscal quarters.

(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.

(c) CILCORP must maintain the required interest coverage ratio and debt-to-capital ratio in order to make any payment of dividends or intercompany loans to affiliates other than direct or indirect subsidiaries.

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. Even if CILCORP is not in compliance with these restrictions, CILCORP may still make payments of dividends or intercompany loans if its senior long-term debt rating is at least BB+ from S&P, Baa2 from Moody's, and BBB from Fitch. At December 31, 2008, CILCORP's senior long-term debt ratings from S&P, Moody's and Fitch were BB+, Ba2, and BBB-, respectively. The common stock of CILCO is pledged as security to the holders of CILCORP's senior notes and bonds and credit facility obligations.

In order for the Ameren Companies to issue securities in the future, they will have to comply with any applicable tests in effect at the time of any such issuances.

**Off-Balance-Sheet Arrangements**

At December 31, 2008, 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, 2008, 2007 and 2006:

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| **Ameren:[(a)]** | | | |
| Miscellaneous income: | | | |

| | | | |
|---|---|---|---|
| Interest and dividend income | $ 15 | $ 27 | $ 10 |
| Interest income on industrial development revenue bonds | 28 | 28 | 28 |
| Allowance for equity funds used during construction | 28 | 5 | 4 |
| Other | 9 | 15 | 8 |
| Total miscellaneous income | $ 80 | $ 75 | $ 50 |
| Miscellaneous expense: | | | |
| Donations | $ (13) | $ (13) | $ (5) |
| Other | (18) | (12) | (14) |
| Total miscellaneous expense | $ (31) | $ (25) | $ (19) |

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| **UE:** | | | |
| Miscellaneous income: | | | |
| Interest and dividend income | $ 5 | $ 4 | $ 3 |
| Interest income on industrial development revenue bonds | 28 | 28 | 28 |
| Allowance for equity funds used during construction | 28 | 4 | 3 |
| Other | 1 | 2 | 4 |
| Total miscellaneous income | $ 62 | $ 38 | $ 38 |
| Miscellaneous expense: | | | |
| Donations | $ (3) | $ (2) | $ (2) |
| Other | (6) | (5) | (6) |
| Total miscellaneous expense | $ (9) | $ (7) | $ (8) |
| **CIPS:** | | | |
| Miscellaneous income: | | | |
| Interest and dividend income | $ 9 | $ 16 | $ 15 |
| Other | 2 | 1 | 2 |
| Total miscellaneous income | $ 11 | $ 17 | $ 17 |
| Miscellaneous expense: | | | |
| Donations | $ (2) | $ (2) | $ (1) |
| Other | (1) | (1) | (1) |
| Total miscellaneous expense | $ (3) | $ (3) | $ (2) |
| **Genco:** | | | |
| Miscellaneous income: | | | |
| Interest and dividend income | $ 1 | $ - | $ - |
| Total miscellaneous income | $ 1 | $ - | $ - |
| Miscellaneous expense: | | | |
| Other | $ (1) | $ - | $ - |
| Total miscellaneous expense | $ (1) | $ - | $ - |
| **CILCORP:** | | | |
| Miscellaneous income: | | | |
| Interest and dividend income | $ 1 | $ 4 | $ 2 |
| Other | 1 | 1 | - |
| Total miscellaneous income | $ 2 | $ 5 | $ 2 |
| Miscellaneous expense: | | | |
| Donations | $ (2) | $ (1) | $ (1) |
| Other | (3) | (4) | (3) |
| Total miscellaneous expense | $ (5) | $ (5) | $ (4) |
| **CILCO:** | | | |
| Miscellaneous income: | | | |
| Interest and dividend income | $ 1 | $ 4 | $ 1 |
| Other | 1 | 1 | - |
| Total miscellaneous income | $ 2 | $ 5 | $ 1 |
| Miscellaneous expense: | | | |
| Donations | $ (2) | $ (1) | $ (1) |
| Other | (3) | (5) | (3) |
| Total miscellaneous expense | $ (5) | $ (6) | $ (4) |
| **IP:** | | | |
| Miscellaneous income: | | | |
| Interest and dividend income | $ 5 | $ 8 | $ 4 |
| Other | 6 | 6 | 2 |
| Total miscellaneous income | $ 11 | $ 14 | $ 6 |
| Miscellaneous expense: | | | |
| Donations | $ (3) | $ (3) | $ (1) |
| Other | (2) | (2) | (3) |

| | | | |
|---|---|---|---|
| Total miscellaneous expense | **$ (5)** | $ (5) | $ (4) |

(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, fuel, electricity, and emission allowances. Price fluctuations in natural gas, fuel, and electricity may cause any of 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 fuel and natural gas inventories or purchased power that differ from the cost of those commodities in inventory; or
- 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.

Certain derivative contracts are entered into on a regular basis as part of our risk management program, but these do not qualify for hedge accounting or the normal purchase and normal sales exceptions under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended.

Accordingly, such contracts are recorded at fair value. Changes in the fair value are charged or credited to the income statement in the period in which the change occurs. Contracts we enter into as part of our risk management program may be settled financially, by physical delivery, or net settled with the counterparty.

### Cash Flow Hedges

Our risk management processes identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The mark-to-market value of cash flow hedges will continue to fluctuate with changes in market prices up to contract expiration.

We monitor and value derivative positions daily as part of our risk management processes. We use published sources for pricing when possible to mark positions to market. We rely on modeled valuations only when no other method exists.

The following table presents the pretax net gain (loss) for the years ended December 31, 2008, 2007 and 2006, of power hedges included in Operating Revenues - Electric. This pretax net gain (loss) represents the impact of discontinued cash flow hedges, the ineffective portion of cash flow hedges, and the reversal of amounts previously recorded in OCI for transactions that have since been delivered or settled:

| Gains (Losses) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Ameren | **$ 103** | $ 40 | $ 9 |
| UE | **7** | - | 11 |
| Genco | **-** | - | 2 |
| IP | **-** | - | (7) |

(a) Includes amounts from Ameren registrants and non-registrant subsidiaries.

### Other Derivatives

The following table represents the net change in market value for the years ended December 31, 2008, 2007 and 2006, of option and swap transactions used to manage our positions in $SO_2$ allowances, coal, heating oil, FTRs and power. Certain of these transactions are treated as nonhedge transactions under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended. The net changes in the market value of nonhedge power and gas transactions are recorded in Operating Revenues - Electric, and Operating Revenues - Gas, while the net changes in the market value of coal, heating oil, and $SO_2$ options and swaps is recorded as Operating Expenses - Fuel.

| Gains (Losses) | 2008 | 2007 | 2006 |
|---|---|---|---|
| **$SO_2$ options and swaps:** | | | |
| Ameren[a] | $ - | $ 8 | $ (2) |
| UE | - | 6 | 4 |
| Genco | - | 1 | (4) |
| **Coal options:** | | | |
| Ameren[a] | - | 2 | (2) |
| UE | - | 2 | (2) |
| **Heating oil options:** | | | |
| Ameren[a] | (53) | 6 | (2) |
| UE | (26) | 1 | - |
| Genco | (16) | 1 | - |
| CILCORP/CILCO | (3) | - | - |
| **FTRs:** | | | |
| Ameren[a] | 3 | - | - |
| UE | 2 | - | - |
| **Nonhedge power swaps and forwards:** | | | |
| Ameren[a] | 2 | (2) | - |
| **Gas forwards and swaps:** | | | |
| Ameren[a] | (12) | - | - |
| UE | (3) | - | - |
| CILCORP/CILCO | (6) | - | - |

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

During the third quarter ended September 30, 2008, UE entered into foreign currency forward contracts. These derivative instruments are intended to fix the amount of U.S. dollars UE will pay for future equipment deliveries denominated in euros as part of a firm commitment to purchase heavy forgings, which would be used in building a second nuclear unit. These forward contracts qualify as fair value hedges and, as a result, both the derivative positions and the foreign currency exposure on the firm commitment are recorded at fair value. Changes in the fair value of both the derivative instrument and the hedged item are recorded in earnings. For the year ended December 31, 2008, this hedging program was highly effective, resulting in no impact to net income.

The following table presents the carrying value of all derivative instruments and the amount of pretax net gains (losses) on derivative instruments in Accumulated OCI, regulatory assets, or regulatory liabilities, at December 31, 2008 and 2007:

| | Ameren[a] | UE | CIPS | Genco | CILCORP/ CILCO | IP |
|---|---|---|---|---|---|---|
| **2008:** | | | | | | |
| Derivative instruments carrying value: | | | | | | |
| Other current assets | $ 207 | $ 50 | $ - | $ - | $ - | $ - |
| Other assets | 47 | - | - | - | - | - |
| Other current liabilities | 155 | 24 | 31 | 1 | 29 | 56 |
| Other deferred credits and liabilities[b] | 79 | 10 | 53 | - | 30 | 78 |
| Gains (losses) deferred in Accumulated OCI: | | | | | | |
| Power forwards[c] | 84 | 40 | - | - | - | - |
| Interest rate swaps[d][e] | (11) | - | - | (11) | - | - |
| Gains (losses) deferred in regulatory assets or liabilities: | | | | | | |
| Gas forwards and futures contracts[f] | (118) | (16) | (27) | - | (25) | (50) |
| Financial contracts[g] | - | - | (56) | - | (29) | (85) |
| **2007:** | | | | | | |
| Derivative instruments carrying value: | | | | | | |
| Other current assets | $ 35 | $ 7 | $ 1 | $ 2 | $ 2 | $ 2 |
| Other assets | 9 | 1 | 38 | - | 20 | 61 |
| Other current liabilities | 24 | 1 | 1 | 6 | 1 | 8 |
| Other deferred credits and liabilities | 7 | - | - | - | - | - |
| Gains (losses) deferred in Accumulated OCI: | | | | | | |
| Power forwards | 15 | 4 | - | - | - | - |
| Interest rate swaps | (2) | - | - | (2) | - | - |
| Gas swaps and futures contracts | - | - | - | - | 1 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| Coal options | 1 | 1 | - | - | - | - |
| Gains (losses) deferred in regulatory assets or liabilities: | | | | | | |
| Gas forwards and futures contracts | (2) | 1 | (1) | - | - | (2) |
| Financial contracts(g) | - | - | 40 | - | 19 | 57 |

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Includes Ameren's and UE's carrying value of fair value foreign currency forward contracts.
(c) Represents the mark-to-market value for the hedged portion of electricity price exposure for periods of up to three years, including $123 million and $39 million in 2009 at Ameren and UE, respectively.
(d) Includes a gain associated with interest rate swaps at Genco that were a partial hedge of the interest rate on debt issued in June 2002. The swaps cover the first 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, 2008 was $2 million.
(e) Includes a loss 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 cumulative gain and loss on the interest rate swaps will be amortized over a 10-year period that began in April 2008. The carrying value at December 31, 2008, was $13 million.
(f) Represents gains associated with natural gas swaps and futures contracts. The swaps are a partial hedge of our natural gas requirements through October 2012 at UE, through March 2013 at CIPS and IP, and through March 2012 at CILCORP and CILCO.
(g) Current losses deferred as regulatory assets of $14 million at CIPS, $7 million at CILCO, and $21 million at IP that were recorded in other current assets at December 31, 2008. Current gains deferred as regulatory liabilities include $2 million at CIPS, $1 million at CILCO, and $2 million at IP that were recorded in other current liabilities at December 31, 2007.

As part of the Illinois electric settlement agreement, the Ameren Illinois Utilities entered into financial contracts with Marketing Company. These financial contracts are derivative instruments being accounted for as cash flow hedges at the Ameren Illinois Utilities and Marketing Company. 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. In Ameren's consolidated financial statements, all financial statement effects of the derivative instruments are eliminated. See Note 2 - Rate and Regulatory Matters for additional information on these financial contracts.

Derivative instruments are subject to various credit-related losses in the event of nonperformance by counterparties to the contracts. In order to mitigate these risks, collateral requirements are established. As of December 31, 2008, Ameren, UE, CIPS, CILCORP, CILCO and IP had collateral postings with external parties of $109 million, $15 million, $26 million, $16 million, $16 million, and $36 million, respectively. The amount of collateral external counterparties posted with Ameren was $7 million at December 31, 2008. The amounts of collateral external counterparties posted with UE, CIPS, CILCORP, CILCO, and IP were immaterial at December 31, 2008. See Note 14 - Related Party Transactions for information regarding collateral postings with affiliates.

On September 15, 2008, Lehman filed for protection under Chapter 11 of the federal Bankruptcy Code in the U.S. Bankruptcy Court in the Southern District of New York. On October 21, 2008, Ameren sent notice to Lehman Commodity Services terminating all transactions between Genco, UE, and Marketing Company and Lehman Commodity Services. As of December 31, 2008, Ameren's and its subsidiaries' direct exposure to Lehman Commodity Services, based on existing transactions and current market prices, was estimated to be less than $1 million before taxes, collectively.

**NOTE 8 - FAIR VALUE MEASUREMENTS**

SFAS No. 157 provides a framework for measuring fair value for all assets and liabilities that are measured and reported at fair value. The Ameren Companies adopted SFAS No. 157 as of the beginning of their 2008 fiscal year for financial assets and liabilities and as of the beginning of their 2009 fiscal year for nonfinancial assets and liabilities, except those already reported at fair value on a recurring basis. The impact of the adoption of SFAS No. 157 for financial assets and liabilities at January 1, 2008, and for nonfinancial assets and liabilities at January 1, 2009, was not material. SFAS No. 157 defines fair value 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 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. SFAS No. 157 also establishes 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 primarily include 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 as part of the Illinois electric settlement agreement. We value Level 3 instruments 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, a review 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 SFAS No. 157. 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.

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). SFAS No. 157 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 $5 million in losses in the fourth quarter of 2008 related to valuation adjustments for counterparty default risk. At December 31, 2008, the counterparty default risk valuation adjustment related to net derivative (assets) liabilities totaled $(1) million, $- million, $9 million, $6 million, and $16 million for Ameren, UE, CIPS, CILCORP/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, 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 |
| CIPS | Derivative assets[b] | - | - | - | - |
| Genco | Derivative assets[b] | - | - | - | - |
| CILCORP/CILCO | Derivative assets[b] | - | - | - | - |
| IP | Derivative assets[b] | - | - | - | - |
| **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 |
| CILCORP/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 of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 31, 2008:

| | | Beginning Balance at January 1, 2008 | Realized and Unrealized Gains (Losses) | | | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Included in Earnings[a] | Included In OCI | Included in Regulatory Assets/ Liabilities | | | | | |
| 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) | - |
| | CILCORP/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 | - |

(a) Net gains and losses on power options are recorded in Operating Revenues - Electric, while net gains and losses on coal, heating oil, and $SO_2$ options and swaps are recorded as Operating Expenses - Fuel.

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 compared with previous periods for the year ended December 31, 2008. 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.

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, 2008 and 2007:

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| **Ameren:[a]** | | | | |
| Long-term debt and capital lease obligations (including current portion) | **$ 6,934** | **$ 6,144** | $ 5,912 | $ 5,821 |
| Preferred stock | **195** | **100** | 211 | 147 |
| **UE:** | | | | |
| Long-term debt and capital lease obligations (including current portion) | **$ 3,677** | **$ 3,156** | $ 3,360 | $ 3,255 |
| Preferred stock | **113** | **62** | 113 | 85 |
| **CIPS:** | | | | |
| Long-term debt (including current portion) | **$ 421** | **$ 371** | $ 471 | $ 472 |
| Preferred stock | **50** | **22** | 50 | 27 |
| **Genco:** | | | | |
| Long-term debt (including current portion) | **$ 774** | **$ 661** | $ 474 | $ 510 |

| | | | | |
|---|---|---|---|---|
| **CILCORP:** | | | | |
| Long-term debt (including current portion) | **$ 662** | **$ 630** | $ 537 | $ 516 |
| Preferred stock | **19** | **10** | 35 | 27 |
| **CILCO:** | | | | |
| Long-term debt (including current portion) | **$ 279** | **$ 255** | $ 148 | $ 149 |
| Preferred stock | **19** | **10** | 35 | 27 |
| **IP:** | | | | |
| Long-term debt (including current portion) | **$ 1,400** | **$ 1,326** | $ 1,070 | $ 1,067 |
| Preferred stock | **46** | **24** | 46 | 32 |

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

## 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 further 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, 2008, and 2007.

Investments by the nuclear decommissioning trust fund have a target allocation of 60% to 70% in equity securities with the balance invested in fixed-income securities. Due to recent market conditions, the equity securities weighting was below 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 on those sales for the years ended December 31, 2008, 2007 and 2006:

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Proceeds from sales | **$ 497** | $ 128 | $ 98 |
| Gross realized gains | **5** | 4 | 2 |
| Gross realized losses | **8** | 3 | 2 |

Net realized and unrealized gains and losses are reflected in regulatory assets or regulatory liabilities on Ameren's and UE's Consolidated Balance Sheets. This reporting is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which we believe would 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, 2008 and 2007:

| Security Type | Cost | Gross Unrealized Gain | Gross Unrealized Loss | Fair Value |
|---|---|---|---|---|
| **2008:** | | | | |
| Debt securities | **$ 109** | **$ 5** | **$ 3** | **$ 111** |
| Equity securities | **123** | **40** | **29** | **134** |
| Cash | **2** | **-** | **-** | **2** |
| Other[a] | **(8)** | **-** | **-** | **(8)** |
| Total | **$ 226** | **$ 45** | **$ 32** | **$ 239** |
| **2007:** | | | | |
| Debt securities | $ 109 | $ 3 | $ 1 | $ 111 |
| Equity securities | 104 | 97 | 7 | 194 |
| Cash | 1 | - | - | 1 |
| Other[a] | 1 | - | - | 1 |
| Total | $ 215 | $ 100 | $ 8 | $ 307 |

(a) 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, 2008:

| | Cost | Fair Value |
|---|---|---|

| | | |
|---|---|---|
| Less than 5 years | $ 40 | $ 40 |
| 5 years to 10 years | 37 | 38 |
| Due after 10 years | 32 | 33 |
| Total | $ 109 | $ 111 |

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 with the NRC to extend its 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, 2008:

| | 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 | $ 20 | $ 2 | $ 7 | $ 1 | $ 27 | $ 3 |
| Equity securities | 30 | 16 | 6 | 13 | 36 | 29 |
| Total | $ 50 | $ 18 | $ 13 | $ 14 | $ 63 | $ 32 |

## NOTE 10 - STOCKHOLDER RIGHTS PLAN AND PREFERRED STOCK

### Stockholder Rights Plan

In 1998, Ameren's board of directors adopted a share purchase rights plan designed to assure stockholders of fair and equal treatment in the event of a proposed takeover. The rights were exercisable only if a person or group acquired 15% or more of Ameren's outstanding common stock or announced a tender offer that would result in ownership by a person or group of 15% or more of the Ameren common stock. Ameren's stockholder rights plan expired on October 9, 2008, and Ameren's Board of Directors decided not to renew it.

### Preferred Stock

All classes of UE's, CIPS', CILCO's and IP's preferred stock are entitled to cumulative dividends and have voting rights. Ameren has 100 million shares of $0.01 par value preferred stock authorized, with no shares outstanding. CIPS has 2.6 million shares of no par value preferred stock authorized, with no shares outstanding. UE has 7.5 million shares of $1 par value preference stock authorized and CILCO has 2 million shares of no par value preference stock authorized, with no such preference stock 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. No shares of preference stock have been issued by any of the Ameren Companies.

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 entitled to cumulative dividends and is redeemable, at the option of the issuer, at the prices presented as of December 31, 2008 and 2007:

| | | Redemption Price (per share) | 2008 | 2007 |
|---|---|---|---|---|
| **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 |
| $7.64 Series | 330,000 shares | 103.82[b] | **33** | 33 |
| Total | | | **$ 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) Declining to $100 per share in 2012.

## NOTE 11 - RETIREMENT BENEFITS

We offer defined benefit and postretirement benefit plans covering substantially all employees of UE, CIPS, CILCORP, 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.

We adopted the provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)," effective December 31, 2006. SFAS No. 158 requires employers to recognize the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, as an asset or liability in their balance sheets. Employers must also recognize as a component of OCI, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. Upon adoption of this provision, Ameren recorded the unfunded obligation of its defined benefit and postretirement benefit plans. The unfunded obligation is the difference between plan assets and the projected benefit obligation for defined benefit plans or accumulated postretirement benefit obligation for postretirement benefit plans. Ameren's adoption of SFAS No. 158 resulted in increases (decreases) to Ameren's, UE's, CIPS', Genco's, CILCORP's, CILCO's, and IP's accrued pension and other postretirement benefits of $406 million, $234 million, $95 million, $36 million, $(51) million, $55 million, and $(8) million, respectively. UE, CIPS, CILCO and IP recorded regulatory assets of $270 million, $108 million, $63 million, and $205 million, respectively, based on the expected recovery of these costs from ratepayers. The adoption of SFAS No. 158 had no material impact on accumulated other comprehensive income at Ameren. CILCORP and IP recognized gains in accumulated other comprehensive income of $29 million and $5 million, respectively, net of taxes, as a result of SFAS No. 158 obligations being reduced from those previously recognized. Genco and CILCO recorded a charge to accumulated other comprehensive income of $25 million and $2 million, respectively, net of taxes.

### Investment Strategy and Return on Asset Assumption

The primary objective of the Ameren retirement plan and postretirement benefit plans is to provide eligible employees with pension and postretirement health care benefits. Ameren manages plan assets in accordance with the "prudent investor" guidelines contained in ERISA. Ameren's goal is to earn the highest possible return on plan assets consistent with its tolerance for risk. Ameren delegates investment management to specialists in each asset class. Where appropriate, Ameren provides the investment manager with guidelines that specify allowable and prohibited investment types. Ameren regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Projected rates of return for each asset class were estimated after an analysis of historical experience, future expectations, and the volatility of the various asset classes. After considering the target asset allocation for each asset class, we adjusted the overall expected rate of return for the

portfolio for historical and expected experience of active portfolio management results compared with benchmark returns and for the effect of expenses paid from plan assets.

Pension benefits are based on the employees' years of service and compensation. Ameren's pension plans are funded in compliance with income tax regulations and to achieve federal funding or regulatory requirements. As a result, Ameren expects to fund its pension plans at a level equal to the greater of the pension expense or the legally required minimum contribution. Taking into consideration our assumptions at December 31, 2008, the investment performance in 2008, and our pension funding policy, Ameren expects to make annual contributions of $90 million to $200 million in each of the next five years. We expect UE's, CIPS', Genco's, CILCO's, and IP's portion of the future funding requirements to be 61%, 6%, 10%, 9%, and 14%, respectively. These amounts are estimates. They may change with actual investment performance, changes in interest rates, any pertinent changes in government regulations, and any voluntary contributions. Our 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 benefit liability recorded in the balance sheets of each of the Ameren Companies as of December 31, 2008:

| | 2008 |
|---|---|
| Ameren[a] | $ 1,499 |
| UE | 496 |
| CIPS | 79 |
| Genco | 67 |
| CILCORP | 216 |
| CILCO | 216 |
| IP | 314 |

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

The following table presents the funded status of our pension and postretirement benefit plans for the years ended December 31, 2008 and 2007:

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | Pension Benefits[a] | Postretirement Benefits[a] | Pension Benefits[a] | Postretirement Benefits[a] |
| Change in benefit obligation: | | | | |
| Net benefit obligation at beginning of year | $ 3,076 | $ 1,253 | $ 3,120 | $ 1,297 |
| Service cost | 60 | 18 | 63 | 21 |
| Interest cost | 186 | 70 | 180 | 72 |
| Plan amendments | 2 | - | 3 | - |
| Participant contributions | - | 14 | - | 12 |
| Actuarial (gain) loss | 145 | (105) | (126) | (83) |
| Reflection of Medicare Part D: | | | | |
| Benefits paid | (166) | (73) | (164) | (71) |
| Less federal subsidy on benefits paid | - | 5 | - | 5 |
| Net benefit obligation at end of year | 3,303 | 1,182 | 3,076 | 1,253 |
| Accumulated benefit obligation at end of year | 3,051 | (b) | 2,837 | (b) |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of year | 2,698 | 787 | 2,608 | 742 |
| Actual return on plan assets | (205) | (187) | 202 | 49 |
| Employer contributions | 66 | 47 | 52 | 51 |
| Federal subsidy on benefits paid | - | 5 | - | 4 |
| Participant contributions | - | 14 | - | 12 |
| Benefits paid | (166) | (73) | (164) | (71) |
| Fair value of plan assets at end of year | 2,393 | 593 | 2,698 | 787 |
| Funded status - deficiency | 910 | 589 | 378 | 466 |
| Accrued benefit cost at December 31 | $ 910 | $ 589 | $ 378 | $ 466 |
| Amounts recognized in the balance sheet consist of: | | | | |
| Current liability | $ 2 | $ 2 | $ 3 | $ 2 |
| Noncurrent liability | 908 | 587 | 375 | 464 |
| Total | $ 910 | $ 589 | $ 378 | $ 466 |

| | | | | |
|---|---|---|---|---|
| Amounts recognized in regulatory assets consist of: | | | | |
| Net actuarial loss | **$ 597** | **$ 327** | $ 142 | $ 233 |
| Prior service cost (credit) | **40** | **(40)** | 49 | (45) |
| Transition obligation | **-** | **12** | - | 16 |
| Amounts recognized in accumulated OCI consist of: | | | | |
| Net actuarial (gain) loss | **57** | **43** | (34) | 17 |
| Prior service cost (credit) | **10** | **(16)** | 10 | (20) |
| Transition obligation | **-** | **-** | - | - |
| Total | **$ 704** | **$ 326** | $ 167 | $ 201 |

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

Ameren's current reconciliation of funded status shows certain amounts that will be recognized as a benefit cost in future years. The unrecognized loss in postretirement benefits is largely a result of declining discount rates over the past several years and market losses on plan assets.

No plan assets are expected to be returned to Ameren during 2009.

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, resulting 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. Ameren's postretirement benefit plan did not have a similar interest rate hedge.

The following table presents the assumptions used to determine our benefit obligations at December 31, 2008 and 2007:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| Discount rate at measurement date | **5.75%** | 6.15% | **5.75%** | 6.05% |
| Increase in future compensation | **4.00** | 4.00 | **4.00** | 4.00 |
| Medical cost trend rate (initial) | **-** | - | **7.00** | 9.00 |
| Medical cost trend rate (ultimate) | **-** | - | **5.00** | 5.00 |
| Years to ultimate rate | **-** | - | **4 years** | 4 years |

The following table presents the cash contributions made to our defined benefit retirement plan qualified trusts and to our postretirement plans during 2008 and 2007:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| Ameren[(a)] | **$ 66** | $ 52 | **$ 47** | $ 51 |
| UE | **36** | 28 | **13** | 27 |
| CIPS | **5** | 5 | **2** | 4 |
| Genco | **5** | 4 | **-** | - |
| CILCORP | **7** | 4 | **8** | 13 |
| CILCO | **7** | 4 | **8** | 13 |
| IP | **11** | 9 | **24** | 7 |

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

Ameren determines the discount rate assumptions by using an interest rate yield curve to make judgments pursuant to EITF No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Postretirement Benefit Plans Other Than Pensions." The yield curve is based on the yields of more than 300 high-quality, noncallable 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.

In determining the current year market-related asset value, the prior-year market-related value of assets is adjusted by 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 following table presents our target allocations for 2009 and our pension and postretirement plan asset categories as of December 31, 2008 and 2007. Ameren's pension plan debt security weighting was at the high end of the target allocation range at the end of 2008. Due to current market conditions, Ameren expects the debt security weighting will remain near the high end of the target allocation range in 2009.

| Asset Category | Target Allocation 2009 | Percentage of Plan Assets at December 31, 2008 | 2007 |
|---|---|---|---|
| **Pension Plan:** | | | |
| Equity securities | 30 - 80% | **36%** | 52% |
| Debt securities | 25 - 60 | **56** | 40 |
| Real estate | 0 - 10 | **6** | 6 |
| Other | 0 - 10 | **2** | 2 |
| Total | | **100%** | 100% |
| **Postretirement Plan:** | | | |
| Equity securities | 30 - 80% | **51%** | 62% |
| Debt securities | 15 - 55 | **43** | 33 |
| Other | 0 - 15 | **6** | 5 |
| Total | | **100%** | 100% |

The following table presents the components of the net periodic benefit cost for our pension and postretirement benefit plans during 2008, 2007 and 2006:

| | Pension Benefits Ameren[a] | Postretirement Benefits Ameren[a] |
|---|---|---|
| **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 |
| **2006:** | | |
| Service cost | $ 63 | $ 22 |
| Interest cost | 173 | 72 |
| Expected return on plan assets | (198) | (50) |
| Amortization of: | | |
| Transition obligation | - | 2 |
| Prior service cost | 11 | (7) |
| Actuarial loss | 42 | 35 |
| Net periodic benefit cost | $ 91 | $ 74 |

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

The estimated amounts that will be amortized from regulatory assets and accumulated OCI into net periodic benefit cost in 2009 are as follows:

| | Pension Benefits | Postretirement Benefits |
|---|---|---|
| | Ameren[a] | Ameren[a] |
| Regulatory assets: | | |
| Net actuarial loss | $ 39 | $ 20 |
| Prior service cost (credit) | 8 | (4) |
| Transition obligation | - | 4 |
| Accumulated OCI: | | |
| Net actuarial loss | $ 1 | $ - |
| Prior service cost (credit) | 2 | (3) |
| Transition obligation | - | - |
| Total | $ 50 | $ 17 |

(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, CILCORP, CILCO and IP are responsible for their share of the pension and postretirement costs. The following table presents the pension costs and the postretirement benefit costs incurred for the years ended December 31, 2008, 2007 and 2006:

| | Pension Costs | | | Postretirement Costs | | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Ameren[a] | **$ 47** | $ 70 | $ 91 | **$ 33** | $ 58 | $ 74 |
| UE | **35** | 44 | 51 | **13** | 26 | 40 |
| CIPS | **7** | 10 | 11 | **3** | 6 | 9 |
| Genco | **5** | 7 | 9 | **2** | 3 | 3 |
| CILCORP | **(2)** | - | 10 | **1** | 8 | 9 |
| CILCO | **5** | 8 | 13 | **6** | 13 | 14 |
| IP | **(2)** | 4 | 9 | **14** | 13 | 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, 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 |
| 2009 | $ 192 | $ 3 | $ 83 | $ 2 | $ 5 |
| 2010 | 194 | 3 | 89 | 2 | 6 |
| 2011 | 200 | 3 | 94 | 3 | 6 |
| 2012 | 207 | 3 | 97 | 3 | 6 |
| 2013 | 213 | 2 | 100 | 3 | 6 |
| 2014 - 2018 | 1,183 | 10 | 530 | 13 | 33 |

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, 2008, 2007 and 2006:

| | Pension Benefits | | | Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| **Ameren, UE, CIPS , Genco, CILCORP, CILCO and IP:** | | | | | | |
| Discount rate at measurement date | **6.15%** | 5.85% | 5.60% | **6.05%** | 5.80% | 5.60% |
| Expected return on plan assets[a] | **8.25** | 8.50 | 8.50 | **8.25** | 8.50 | 8.50 |
| Increase in future compensation | **4.00** | 4.00 | 3.25 | **4.00** | 4.00 | 3.25 |
| Medical cost trend rate (initial) | **-** | - | - | **9.00** | 9.00 | 8.00 |
| Medical cost trend rate (ultimate) | **-** | - | - | **5.00** | 5.00 | 5.00 |
| Years to ultimate rate | **-** | - | - | **4 years** | 4 years | 3 years |

(a) The Ameren Companies will utilize an expected return on plan assets of 8% in 2009.

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 | $ 1 | $ 104 | $ - | $ 30 |
| 0.25% increase in salary scale | 2 | 13 | - | - |
| 1.00% increase in annual medical trend | - | - | 2 | 29 |
| 1.00% decrease in annual medical trend | - | - | (2) | (26) |

**Other**

Ameren sponsors a 401(k) plan for eligible employees. The Ameren plan covered all eligible employees of the Ameren Companies at December 31, 2008. 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 $23 million, $21 million, and $19 million in 2008, 2007, and 2006, respectively. Prior to February 1, 2008, CIPS employees represented by IBEW Local 702 were covered by a separate 401(k) plan. The CIPS-related 401(k) plan was merged into the Ameren plan effective February 1, 2008. CIPS' matching contributions to the CIPS-related 401(k) plan were less than $1 million annually in 2008, 2007 and 2006.

The following table presents the portion of the 401(k) matching contribution to the Ameren plan for each of the Ameren Companies for the years ended December 31, 2008, 2007 and 2006:

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Ameren[a] | **$ 23** | $ 21 | $ 19 |
| UE | **14** | 14 | 13 |
| CIPS | **2** | 1 | 1 |
| Genco | **2** | 1 | 1 |
| CILCORP | **2** | 2 | 2 |
| CILCO | **2** | 2 | 2 |
| IP | **2** | 3 | 2 |

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

**NOTE 12 - STOCK-BASED COMPENSATION**

Ameren's long-term incentive plan for eligible employees, called the Long-term Incentive Plan of 1998 (1998 Plan), was replaced prospectively by the 2006 Omnibus Incentive Compensation Plan (2006 Plan) effective May 2, 2006. The 2006 Plan provides for a maximum of 4 million common shares to be available for grant to eligible employees and directors. No new awards may be granted under the 1998 Plan; however, previously granted awards continue to vest or to be exercisable in accordance with their original terms and conditions. The 2006 Plan awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance share units, cash-based awards, and other stock-based awards.

A summary of nonvested shares as of December 31, 2008, and changes during the year ended December 31, 2008, under the 1998 Plan and the 2006 Plan are presented below:

| | Performance Share Units | | Restricted Shares | |
|---|---|---|---|---|
| | Shares | Weighted-average Fair Value Per Unit | Shares | Weighted-average Fair Value Per Share |
| Nonvested at January 1, 2008 | 669,403 | $ 57.88 | 316,768 | $ 46.23 |
| Granted[a] | 495,847 | 32.35 | - | - |
| Dividends | - | - | 13,364 | 38.91 |
| Unearned or forfeited[b] | (213,854) | 55.82 | (2,163) | 48.19 |
| Earned and vested[c] | (275,419) | 49.37 | (114,286) | 44.05 |
| Nonvested at December 31, 2008 | 675,977 | $ 43.28 | 213,683 | $ 47.46 |

(a) Includes performance share units (share units) granted to certain executive and nonexecutive officers and other eligible employees in February 2008 under the 2006 Plan.
(b) Includes share units granted in 2006 that were not earned based on performance provisions of the award grants.
(c) Includes share units granted in 2006 that vested as of December 31, 2008, 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 $22 million, $18 million, and $11 million for the years ended December 31, 2008, 2007, and 2006,

respectively, and a related tax benefit of $8 million, $7 million, and $4 million for the years ended December 31, 2008, 2007, and 2006, respectively. As of December 31, 2008, total compensation cost of $13 million related to nonvested awards not yet recognized is expected to be recognized over a weighted-average period of 19 months.

**Performance Share Units**

Performance share unit awards were granted under the 1998 Plan and the 2006 Plan from 2006 to 2008. With these awards, 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, Ameren has achieved certain performance goals 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. When a share unit awarded from 2006 to 2008 vests, Ameren will issue the related shares to the employee two years after vesting, but dividends on the shares will be paid to the employee at the same time they are paid to other shareholders.

The fair value of each share unit awarded in February 2008 under the 2006 Plan was determined to be $32.35, based on Ameren's closing common share price of $44.30 per share at the grant date and lattice simulations used to estimate expected share payout based on Ameren's attainment of certain financial measures relative to the designated peer group. 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 maintenance of its $2.54 annual dividend over the performance period.

The fair value of each share unit awarded in February 2007 under the 2006 Plan was determined to be $59.60. That figure was based on Ameren's closing common share price of $53.99 per share at the grant date and lattice simulations used to estimate expected share payout based on Ameren's attainment of certain financial measures relative to the designated peer group. The significant assumptions used to calculate fair value also included a three-year risk-free rate of 4.735%, dividend yields of 2.3% to 5.2% for the peer group, volatility of 12.91% to 18.33% for the peer group, and Ameren's maintenance of its $2.54 annual dividend over the performance period.

**Restricted Stock**

Restricted stock awards in 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**

*Ameren*

Options in 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 85,800 at December 31, 2008, expire on various dates through 2010. There is no expense from stock options for the years ended December 31, 2008, 2007 and 2006, 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, 2008, 2007 and 2006:

| | Ameren | UE | CIPS | Genco | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|---|
| **2008:** | | | | | | | |
| Statutory federal income tax rate: | 35% | 35% | 35% | 35% | 35% | 35% | 35% |
| Increases (decreases) from: | | | | | | | |
| Permanent items[a] | (1) | 1 | (1) | (2) | (3) | (1) | 7 |
| Depreciation differences | - | (1) | (2) | - | (1) | (1) | - |
| Amortization of investment tax credit | (1) | (1) | (10) | - | (1) | (1) | - |
| State tax | 4 | 3 | 5 | 5 | 4 | 5 | 5 |
| Reserve for uncertain tax positions | (1) | (1) | (1) | (1) | 1 | - | 2 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Other[b] | **(2)** | **-** | **(1)** | **(1)** | **(4)** | **(1)** | **1** |
| Effective income tax rate | **34%** | **36%** | **25%** | **36%** | **31%** | **36%** | **50%** |
| **2007:** | | | | | | | |
| Statutory federal income tax rate: | 35% | 35% | 35% | 35% | 35% | 35% | 35% |
| Increases (decreases) from: | | | | | | | |
| Permanent items[a] | (2) | (2) | 2 | (1) | (5) | (2) | 1 |
| Depreciation differences | - | - | 3 | - | (2) | (1) | (3) |
| Amortization of investment tax credit | (1) | (1) | (6) | (1) | (2) | (1) | - |
| State tax | 4 | 4 | 6 | 5 | 3 | 3 | 5 |
| Reserve for uncertain tax positions | (1) | (1) | - | - | - | - | - |
| Other[c] | (1) | (2) | (4) | - | 1 | - | (1) |
| Effective income tax rate | 34% | 33% | 36% | 38% | 30% | 34% | 37% |
| **2006:** | | | | | | | |
| Statutory federal income tax rate: | 35% | 35% | 35% | 35% | 35% | 35% | 35% |
| Increases (decreases) from: | | | | | | | |
| Permanent items[a] | (2) | (2) | - | (4) | (d) | (5) | 1 |
| Sales of noncore properties | (2) | - | - | - | (d) | (2) | - |
| Nondeductible expenses | 1 | 2 | - | - | (d) | - | - |
| Depreciation differences | 1 | 2 | (5) | - | (d) | (3) | - |
| Amortization of investment tax credit | (1) | (1) | (3) | (1) | (d) | (2) | - |
| State tax | 4 | 3 | 5 | 5 | (d) | 5 | 5 |
| Reserve for uncertain tax positions | (1) | - | (2) | (2) | (d) | (11) | - |
| Other[c] | (2) | (1) | (1) | (2) | (d) | - | (1) |
| Effective income tax rate | 33% | 38% | 29% | 31% | (d) | 17% | 40% |

(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, CILCORP and CILCO, company-owned life insurance for Ameren, CILCORP and CILCO, SFAS No. 106-2 Medicare Part D for Ameren, UE, Genco, CILCORP and CILCO, employee stock ownership plan dividends for Ameren, and nondeductible expenses for IP.

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

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

(d) The 2006 difference between the reported federal income tax benefit and income tax expense calculated using the statutory rate resulted primarily from tax benefits from permanent effects of company-owned life insurance ($1 million), Internal Revenue Code Section 199 production activity deductions ($1 million), plant-related depreciation differences ($2 million), investment tax credit amortization ($1 million), adjustments to reserves for uncertain tax positions ($6 million), reconciliation of tax return to accrual ($2 million), leveraged leases ($1 million) and state tax impact of $1 million.

The following table presents the components of income tax expense (benefit) for the years ended December 31, 2008, 2007 and 2006:

| | Ameren[a] | UE | CIPS | Genco | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|---|
| **2008:** | | | | | | | |
| Current taxes: | | | | | | | |
| Federal | **$ 165** | **$ 37** | **$ 4** | **$ 81** | **$ 15** | **$ 25** | **$ (11)** |
| State | **10** | **5** | **3** | **15** | **(9)** | **5** | **(11)** |
| Deferred taxes: | | | | | | | |
| Federal | **130** | **86** | **2** | **5** | **6** | **9** | **17** |
| State | **31** | **11** | **(2)** | **-** | **8** | **1** | **10** |
| Deferred investment tax credits, amortization | **(9)** | **(5)** | **(2)** | **(1)** | **(1)** | **(1)** | **-** |
| Total income tax expense | **$ 327** | **$ 134** | **$ 5** | **$ 100** | **$ 19** | **$ 39** | **$ 5** |

| | Ameren[a] | UE | CIPS | Genco | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|---|
| **2007:** | | | | | | | |
| Current taxes: | | | | | | | |
| Federal | $ 311 | $ 105 | $ 21 | $ 49 | $ 21 | $ 36 | $ 3 |
| State | 17 | 8 | 2 | 9 | 6 | 5 | (2) |
| Deferred taxes: | | | | | | | |
| Federal | 7 | 22 | (10) | 17 | 1 | 1 | 11 |
| State | 4 | 10 | (2) | 4 | (6) | (2) | 3 |
| Deferred investment tax credits, amortization | (9) | (5) | (2) | (1) | (1) | (1) | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Total income tax expense | $ 330 | $ 140 | $ 9 | $ 78 | $ 21 | $ 39 | $ 15 |
| **2006:** | | | | | | | |
| Current taxes: | | | | | | | |
| Federal | $ 179 | $ 123 | $ 21 | $ (6) | $ (16) | $ 3 | $ (33) |
| State | 33 | 22 | 7 | 4 | (3) | (1) | (3) |
| Deferred taxes: | | | | | | | |
| Federal | 80 | 52 | (7) | 20 | 4 | 2 | 63 |
| State | 2 | (7) | (4) | 5 | 5 | 7 | 10 |
| Deferred investment tax credits, amortization | (10) | (6) | (2) | (1) | (1) | (1) | - |
| Total income tax expense (benefit) | $ 284 | $ 184 | $ 15 | $ 22 | $ (11) | $ 10 | $ 37 |

(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, 2008 and 2007:

| | Ameren[a] | UE | CIPS | Genco | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|---|
| **2008:** | | | | | | | |
| Accumulated deferred income taxes, net liability (asset): | | | | | | | |
| Plant related | **$ 2,377** | **$ 1,427** | **$ 182** | **$ 289** | **$ 242** | **$ 242** | **$ 205** |
| Deferred intercompany tax gain/basis step-up | **4** | **(3)** | **90** | **(87)** | **-** | **-** | **-** |
| Regulatory assets (liabilities), net | **37** | **44** | **(4)** | **-** | **(3)** | **(3)** | **-** |
| Deferred benefit costs | **(281)** | **(92)** | **(5)** | **(32)** | **(54)** | **(59)** | **(1)** |
| Purchase accounting | **38** | **-** | **-** | **-** | **43** | **-** | **(33)** |
| Leveraged leases | **6** | **-** | **-** | **-** | **-** | **-** | **-** |
| Asset retirement obligation | **(27)** | **5** | **-** | **(21)** | **(11)** | **(11)** | **-** |
| Other | **(19)** | **(12)** | **(10)** | **2** | **(29)** | **(13)** | **(10)** |
| Total net accumulated deferred income tax liabilities[b] | **$ 2,135** | **$ 1,369** | **$ 253** | **$ 151** | **$ 188** | **$ 156** | **$ 161** |
| **2007:** | | | | | | | |
| Accumulated deferred income taxes, net liability (asset): | | | | | | | |
| Plant related | $ 2,186 | $ 1,355 | $ 171 | $ 276 | $ 224 | $ 224 | $ 149 |
| Deferred intercompany tax gain/basis step-up | 4 | (4) | 99 | (95) | - | - | - |
| Regulatory assets (liabilities), net | 36 | 42 | (2) | - | (3) | (3) | - |
| Deferred benefit costs | (209) | (91) | (8) | (11) | (60) | (54) | 30 |
| Purchase accounting | 33 | - | - | - | 45 | - | (42) |
| Leveraged leases | 7 | - | - | - | - | - | - |
| Asset retirement obligation | (35) | (11) | - | (14) | (9) | (9) | - |
| Other | (39) | (39) | (10) | 12 | (21) | (10) | (2) |
| Total net accumulated deferred income tax liabilities[c] | $ 1,983 | $ 1,252 | $ 250 | $ 168 | $ 176 | $ 148 | $ 135 |

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Includes $3 million, $5 million, $24 million, $15 million, and $15 million as current assets recorded in the balance sheets for UE, CIPS, CILCORP, CILCO, and IP, respectively. Includes $4 million and $15 million as current liabilities recorded in the balance sheets for Ameren and Genco, respectively.
(c) Includes $61 million, $21 million, $8 million, $17 million, $7 million and $13 million as current assets recorded in the balance sheets for Ameren, UE, CIPS, CILCORP, CILCO, and IP, respectively. Includes $7 million as current liabilities recorded in the balance sheet for Genco.

Ameren, CILCORP and IP have Illinois net operating loss carryforwards of $15 million, $11 million, and $4 million, respectively. These will begin to expire in 2019.

On February 20, 2009, the Illinois Supreme Court handed down its decision in *Exelon Corporation v. The Department of Revenue*, which concluded that an electric utility in Illinois qualifies for the Illinois investment tax credit. The decision in the case may have implications for the Ameren Companies' income, sales, and use taxes. The Ameren Companies are assessing the impact the decision may have on their results of operations, financial position or liquidity.

**FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of SFAS No. 109* (FIN 48)**

On January 1, 2007, the Ameren Companies adopted the provisions of FIN 48, which addresses 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 from January 1, 2007, to December 31, 2008, is as follows:

| | Ameren | UE | CIPS | Genco | CILCORP | CILCO | IP |
|---|---|---|---|---|---|---|---|
| Unrecognized tax benefits - January 1, 2007 | $ 155 | $ 58 | $ 15 | $ 36 | $ 18 | $ 18 | $ 12 |
| Increases based on tax positions prior to 2007 | 31 | 4 | - | 10 | 3 | 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 | 5 | - |
| Changes related to settlements with taxing authorities | (60) | (28) | (12) | (4) | (7) | (7) | (10) |
| Decreases related to the lapse of statute of limitations | (6) | (6) | - | - | - | - | - |
| Unrecognized tax benefits - December 31, 2007 | $ 116 | $ 26 | $ - | $ 40 | $ 19 | $ 19 | $ - |
| Increases based on tax positions prior to 2008 | **16** | **2** | **-** | **4** | **2** | **2** | **-** |
| Decreases based on tax positions prior to 2008 | **(46)** | **(13)** | **-** | **(9)** | **(4)** | **(4)** | **-** |
| Increases based on tax positions related to 2008 | **31** | **6** | **-** | **13** | **8** | **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** | **$ 25** | **$ -** |
| Total unrecognized tax benefits (detriments) that, if recognized, would impact the effective tax rates as of December 31, 2008 | **$ 12** | **$ 1** | **$ -** | **$ (2)** | **$ -** | **$ -** | **$ -** |

As of January 1, 2007, the Ameren Companies adopted a policy of recognizing interest expense (income) and penalties accrued on tax liabilities on a pretax basis as interest expense (income) or miscellaneous expense in the statements of income. Prior to January 1, 2007, the Ameren Companies recognized such items in the provision for taxes on a net-of-tax basis.

A reconciliation of the change in the liability (receivable) for interest on unrecognized tax benefits from January 1, 2007, to December 31, 2008, is as follows:

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

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

Ameren is currently under U.S. federal income tax examination by the Internal Revenue Service for years 2005, 2006, and 2007. 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 now 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.

### Illinois Electric Settlement Agreement

As part of the 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 providing $1 billion of funding for rate relief to certain Illinois electric customers, including customers of the Ameren Illinois Utilities. At December 31, 2008, CIPS, CILCO and IP had receivable balances from Genco for

reimbursement of customer rate relief of $1 million, less than $1 million, and $1 million, respectively. Also at December 31, 2008, CIPS, CILCO and IP had receivable balances from AERG for reimbursement of customer rate relief of less than $1 million, less than $1 million, and $1 million, respectively. During the year ended December 31, 2008, Genco incurred charges to earnings of $17 million for customer rate relief contributions and program funding reimbursements to the Ameren Illinois Utilities (CIPS - $6 million, CILCO - $3 million, IP - $8 million), and AERG incurred charges to earnings of $8 million (CIPS - $3 million, CILCO - $1 million, and IP - $4 million). The Ameren Illinois Utilities recorded most of the reimbursements received from Genco and AERG as electric revenue with an immaterial amount recorded as miscellaneous revenue.

Also as part of the 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. 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 being accounted for as cash flow hedges at the Ameren Illinois Utilities and Marketing Company. 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. Below are the contracted volumes and prices per megawatthour.

| Period | Volume | Price per Megawatthour |
|---|---|---|
| June 1, 2008 - December 31, 2008 | 400 MW | $ 47.45 |
| January 1, 2009 - May 31, 2009 | 400 MW | 49.47 |
| June 1, 2009 - December 31, 2009 | 800 MW | 49.47 |
| 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 |

**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, 2008, 2007, and 2006:

| | December 31, | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| Genco sales to Marketing Company[a] | **-** | - | 21,941 |
| Marketing Company sales to CIPS[a] | **-** | - | 12,593 |
| Genco sales to Marketing Company[b] | **16,551** | 17,425 | - |
| AERG sales to Marketing Company[b] | **6,677** | 5,316 | - |
| Marketing Company sales to CIPS[c] | **2,050** | 2,396 | - |
| Marketing Company sales to CILCO[c] | **909** | 1,167 | - |
| Marketing Company sales to IP[c] | **2,870** | 3,493 | - |

(a) These agreements expired or terminated on December 31, 2006.
(b) In December 2006, Genco and Marketing Company, and AERG and Marketing Company, entered into power supply agreements whereby Genco and AERG sell and Marketing Company purchases all the capacity available from Genco's and AERG's generation fleets and all the associated energy commencing on January 1, 2007.
(c) Marketing Company contracted with CIPS, CILCO, and IP to provide power based on the results of the Illinois reverse auction in September 2006. The values in this table reflect the physical sales volumes provided in that agreement.

In December 2006, Genco and Marketing Company entered into a new power supply agreement (Genco PSA) whereby Genco agreed to sell and Marketing Company agreed to purchase all of the capacity available from Genco's generation fleet and all the associated energy. On March 28, 2008, Genco and Marketing Company entered into an amendment of the Genco PSA. Under the amendment, Genco is 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 liability in such case will be for the positive difference, if any, between the market price of capacity and/or energy Genco does not deliver and the contract price under the Genco PSA for that capacity and/or energy. Genco has insurance with an affiliate company that covers many, but not all, of these situations, subject to deductibles and policy limits. An unplanned outage or derate that continues for one year or more is an event of default under the Genco PSA. In the event of Marketing Company's unexcused failure to receive energy under the Genco PSA, Marketing Company would be required to pay Genco the positive difference, if any, between the contract price and the price actually received by Genco, acting in a commercially reasonable manner, to resell the unreceived energy, less any reasonable related transmission, ancillary service, or brokerage costs.

Also in December 2006, AERG and Marketing Company entered into a power supply agreement (AERG PSA) whereby AERG agreed to sell and Marketing Company agreed to purchase all of the capacity available from AERG's generation fleet and all the associated energy. On March 28, 2008, AERG and Marketing Company entered into an amendment of the AERG PSA that is substantially identical to the amendment to the Genco PSA described above. Under the amendment, AERG is liable to Marketing Company in the event of an unplanned outage or derate due to sudden, unanticipated failure or accident within the generating plant site of one or more of its generating units. AERG's liability in such case will be for the positive difference, if any, between the market price of capacity and/or energy AERG does not deliver and the contract price under the AERG PSA for that capacity and/or energy. AERG has insurance with an affiliate company that covers many, but not all of these situations, subject to deductibles and policy limits. An unplanned outage or derate that continues for one year or more is an event of default under the AERG PSA. In the event of Marketing Company's unexcused failure to receive energy under the AERG PSA, Marketing Company would be required to pay AERG the positive difference, if any, between the contract price and the price actually received by AERG, acting in a commercially reasonable manner, to resell the unreceived energy, less any reasonable related transmission, ancillary service, or brokerage costs.

Both the Genco PSA and the AERG PSA 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.

One-third of the Ameren Illinois Utilities' supply contracts that served the load needs of their fixed-price residential and small commercial customers, and all of the supply contracts that served large commercial and industrial customers, expired on May 31, 2008. To replace these expired supply contracts, the Ameren Illinois Utilities used RFP processes in early 2008, pursuant to the Illinois electric settlement agreement, to contract for the necessary energy and capacity requirements 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 and capacity RFPs. Marketing Company entered into financial instruments that fixed the price that the Ameren Illinois Utilities will pay for about two million megawatthours at approximately $60 per megawatthour. 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.

Separately, the Ameren Illinois Utilities used an RFP process to procure ancillary services for 2007 and 2008 required to maintain reliable operation of their transmission systems. Both UE and Marketing Company were among the winning suppliers in both years' ancillary services RFPs. In January 2009, the Ameren Illinois Utilities began procuring ancillary services from the MISO ancillary services market.

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 are required to support the additional electric power upgrades being made at Genco's Coffeen power plant. Under the agreement, Genco will pay CIPS for the costs of the transmission upgrades. When the transmission assets are placed in service, CIPS will be required to repay Genco, with interest, for the costs of the transmission upgrades. At December 31, 2008, CIPS had recorded $2 million in Other Deferred Credits and Liabilities and Genco had recorded $2 million in Accounts Receivable - Affiliates. These transactions were eliminated in consolidation on Ameren's financial statements.

**Joint Dispatch Agreement**

Prior to December 31, 2006, UE and Genco dispatched electric generation under a joint dispatch agreement among UE, CIPS and Genco. UE and Genco had the option to serve their load requirements from their own generation first, and then each could give its affiliates access to any available generation at incremental cost. Any excess generation not used by UE or Genco to serve load requirements was sold to third parties on a short-term basis. To allocate power costs between UE and Genco, an intercompany sale was recorded by the company providing the power. By mutual consent of UE, CIPS, and Genco, the JDA was terminated on December 31, 2006.

The following table presents the amount of gigawatthour sales under the JDA during the year ended December 31, 2006:

| | 2006 |
|---|---|
| UE sales to Genco | 10,072 |
| Genco sales to UE | 3,917 |

The following table presents the short-term power sales margins under the JDA for UE and Genco during the year ended December 31, 2006:

| | 2006 |
|---|---|
| UE | $ 108 |
| Genco | 33 |
| Total | $ 141 |

**Support Services Agreements**

Costs of support services provided by Ameren Services, AFS, and Ameren Energy, Inc., until December 31, 2007, to their affiliates, including wages, employee benefits, professional services, and other expenses are based on, or are an allocation of, actual costs incurred. Ameren Energy, Inc. was dissolved on December 31, 2007.

**Executory Tolling, Gas Sales, and Transportation Agreements**

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.

**Transitional Funding Securitization Financing Agreement**

See Note 1 - Summary of Significant Accounting Policies for further information. In 2008, the TFNs were redeemed.

**Money Pools**

See Note 5 - Long-term Debt and Equity Financings for discussion of affiliate borrowing arrangements.

**Intercompany Borrowings**

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. 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 expense for this note recorded by CIPS and Genco, respectively, was $7 million, $10 million, and $12 million for the years ended December 31, 2008, 2007, and 2006, respectively.

CILCORP had outstanding borrowings directly from Ameren of $152 million and $2 million, at December 31, 2008 and 2007, respectively. The average interest rate on these borrowings was 3.6% for the year ended December 31, 2008 (2007 - 5.14%). CILCORP recorded interest expense of $1 million, less than $1 million, and $7 million for Ameren borrowings for the years ended December 31, 2008, 2007, and 2006, respectively.

UE had outstanding borrowings directly from Ameren of $92 million at December 31, 2008. The average interest rate on these borrowings was 3.6% for the year ended December 31, 2008. UE recorded interest expense of $1 million, $4 million, and $1 million for Ameren borrowings for the years ended December 31, 2008, 2007, and 2006, respectively.

At December 31, 2007, UE held a $30 million intercompany note receivable from its wholly owned subsidiary, Union Electric Development Corporation. This note was transferred to Ameren Development Company from Union Electric Development Corporation in connection with the merger discussed below under Intercompany Transfers. The note was paid off in November 2008. The average interest rate on this note while outstanding during 2008 was 5.17%. UE recorded interest revenue of $2 million for this note for the year ended December 31, 2008.

**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, cash 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, meaning that Marketing Company as the supplier is the only counterparty required to post collateral. At December 31, 2008, there were no collateral postings by Marketing Company related to the 2006 auction power supply agreements, and at December 31, 2007, Marketing Company had posted $1 million, less than $1 million, and $1 million for the benefit of CIPS, CILCO, and IP, respectively.

In addition, under the terms of the 2008 Illinois power procurement RFPs, cash collateral must be posted by Marketing Company and the Ameren Illinois Utilities under certain market conditions. The collateral postings are bilateral, meaning that either counterparty may 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.

**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. Genco recorded operating revenues from the lease agreement of $2 million, $11 million, and $11 million for the three years ended December 31, 2008, 2007, and 2006, respectively. 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.

**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 entire 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 now has an 80% ownership interest in EEI and consolidates it accordingly.

The following table presents the impact on UE, CIPS, Genco, CILCORP, CILCO, and IP of related party transactions for the years ended December 31, 2008, 2007 and 2006. It is based primarily on the agreements discussed above and the money pool arrangements discussed in Note

4 - Short-term Borrowings and Liquidity.

| Agreement | Income Statement Line Item | | UE | CIPS | Genco | CILCORP[a] | IP |
|---|---|---|---|---|---|---|---|
| Genco and AERG power supply agreements with Marketing Company | Operating Revenues | **2008** | **$ (b)** | **$ (b)** | **$ 893** | **$ 344** | **$ (b)** |
| | | 2007 | (b) | (b) | 831 | 279 | (b) |
| Ancillary services and capacity agreements with CIPS, CILCO and IP[c] | Operating Revenues | **2008** | **13** | **(b)** | **(b)** | **(b)** | **(b)** |
| | | 2007 | 18 | (b) | (b) | (b) | (b) |
| Power supply agreement with Marketing Company - expired December 31, 2006 | Operating Revenues | 2006 | (b) | (b) | 793 | 5 | (b) |
| UE and Genco gas transportation agreement | Operating Revenues | **2008** | **1** | **(b)** | **(b)** | **(b)** | **(b)** |
| | | 2007 | 1 | (b) | (b) | (b) | (b) |
| | | 2006 | 1 | (b) | (b) | (b) | (b) |
| JDA - terminated December 31, 2006 | Operating Revenues | 2006 | 196 | (b) | 97 | (b) | (b) |
| Genco gas sales to distribution companies | Operating Revenues | **2008** | **(b)** | **(b)** | **7** | **(b)** | **(b)** |
| **Total Operating Revenues** | | **2008** | **$ 14** | **$ (b)** | **$ 900** | **$ 344** | **$ (b)** |
| | | 2007 | 19 | (b) | 831 | 279 | (b) |
| | | 2006 | 197 | (b) | 890 | 5 | (b) |
| UE and Genco gas transportation agreement | Fuel | **2008** | **$ (b)** | **$ (b)** | **$ 1** | **$ (b)** | **$ (b)** |
| | | 2007 | (b) | (b) | 1 | (b) | (b) |
| | | 2006 | (b) | (b) | 1 | (b) | (b) |
| CIPS, CILCO and IP agreements with Marketing Company[d] | Purchased Power | **2008** | **$ (b)** | **$ 145** | **$ (b)** | **$ 65** | **$ 204** |
| | | 2007 | (b) | 157 | (b) | 76 | 227 |

| Agreement | Income Statement Line Item | | UE | CIPS | Genco | CILCORP[a] | IP |
|---|---|---|---|---|---|---|---|
| Ancillary services and capacity agreements with UE[c] | Purchased Power | **2008** | **(b)** | **4** | **(b)** | **2** | **7** |
| | | 2007 | (b) | 6 | (b) | 3 | 9 |
| Ancillary services agreement with Marketing Company | Purchased Power | **2008** | **(b)** | **6** | **(b)** | **3** | **8** |
| | | 2007 | (b) | 3 | (b) | 1 | 4 |
| JDA - terminated December 31, 2006 | Purchased Power | 2006 | 97 | (b) | 196 | (b) | (b) |
| Power supply agreement with Marketing Company - expired December 31, 2006 | Purchased Power | 2006 | (b) | 448 | (b) | 1 | (b) |
| Executory tolling agreement with Medina Valley | Purchased Power | **2008** | **(b)** | **(b)** | **(b)** | **39** | **(b)** |
| | | 2007 | (b) | (b) | (b) | 38 | (b) |
| | | 2006 | (b) | (b) | (b) | 39 | (b) |
| **Total Purchased Power** | | **2008** | **$ (b)** | **$ 155** | **$ (b)** | **$ 109** | **$ 219** |
| | | 2007 | (b) | 166 | (b) | 118 | 240 |
| | | 2006 | 97 | 448 | 196 | 40 | (b) |
| Insurance recoveries | Operating Revenues and Purchased Power | **2008** | **$ (e)** | **$ (b)** | **$ (11)** | **$ (4)** | **$ (b)** |
| | | 2007 | (12) | (b) | (2) | (7) | (b) |
| Gas purchases from Genco | Gas Purchased for Resale | **2008** | **$ (b)** | **$ (e)** | **$ (b)** | **$ 6** | **$ (b)** |
| Ameren Services support services agreement | Other Operations and Maintenance | **2008** | **$ 130** | **$ 50** | **$ 28** | **$ 51** | **$ 76** |
| | | 2007 | 137 | 47 | 24 | 49 | 73 |
| | | 2006 | 136 | 47 | 23 | 48 | 71 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Ameren Energy, Inc. support services agreement | Other Operations and Maintenance | **2008** | **(f)** | **(b)** | **(f)** | **(b)** | **(b)** |
| | | 2007 | 8 | (b) | (e) | (b) | (b) |
| | | 2006 | 7 | (b) | 2 | (b) | (b) |
| AFS support services agreement | Other Operations and Maintenance | **2008** | **7** | **2** | **3** | **2** | **2** |
| | | 2007 | 6 | 2 | 2 | 2 | 2 |
| | | 2006 | 5 | 1 | 2 | 2 | 2 |
| Insurance premiums(g) | Other Operations and Maintenance | **2008** | **8** | **(b)** | **4** | **3** | **(b)** |
| | | 2007 | 19 | (b) | 4 | 2 | (b) |
| **Total Other Operations and Maintenance Expenses** | | **2008** | **$ 145** | **$ 52** | **$ 35** | **$ 56** | **$ 78** |
| | | 2007 | 170 | 49 | 30 | 53 | 75 |
| | | 2006 | 148 | 48 | 27 | 50 | 73 |
| Money pool borrowings (advances) | Interest (Expense) Income | **2008** | **$ (e)** | **$ (e)** | **$ (e)** | **$ (e)** | **$ (e)** |
| | | 2007 | (e) | (e) | 8 | (e) | 1 |
| | | 2006 | (e) | 2 | 10 | 4 | 2 |

(a) Amounts represent CILCORP and CILCO activity.
(b) Not applicable.
(c) Represents ancillary services to the Ameren Illinois Utilities in 2007 and 2008 and capacity to the Ameren Illinois Utilities beginning in June 2008.
(d) Represents power supply costs under agreements entered into as part of the Illinois September 2006 auction and the 2008 energy and capacity RFPs.
(e) Amount less than $1 million.
(f) Ameren Energy, Inc. was eliminated December 31, 2007, through an internal reorganization.
(g) Represents insurance premiums paid to 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, 2008. 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 | 10,461 | 117.5(b) |
| | $ 10,761(c) | $ 117.5 |
| Property damage: | | |
| Nuclear Electric Insurance Ltd. | $ 2,750(d) | $ 21.6 |
| Replacement power: | | |
| Nuclear Electric Insurance Ltd | $ 490(e) | $ 8.5 |
| Energy Risk Assurance Company | $ 64(f) | $ - |

(a) Provided through mandatory participation in an industry-wide retrospective premium assessment program.
(b) Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended. This is subject to retrospective assessment with respect to a covered loss in excess of $300 million from an incident at any licensed U.S. commercial reactor, payable at $17.5 million per year.
(c) Limit of liability for each incident under Price-Anderson. This limit is subject to change to account for the effects of inflation and changes in the number of licensed reactors.
(d) Provides for $500 million in property damage and decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage.
(e) Provides the replacement power cost insurance in the event of a prolonged accidental outage at a nuclear plant. Weekly indemnity of $4.5 million for 52 weeks, which commences

after the first eight weeks of an outage, plus $3.6 million per week for 71.1 weeks thereafter.

(f) Provides the replacement power cost insurance in the event of a prolonged accidental outage at a 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, 2008:

| | Total | Less than 1 Year | 1 - 3 Years | 3 - 5 Years | After 5 Years |
|---|---|---|---|---|---|
| **Ameren:**[a] | | | | | |
| Capital lease payments[b] | $ 717 | $ 32 | $ 65 | $ 65 | $ 555 |
| Less amount representing interest | 395 | 28 | 56 | 55 | 256 |
| Present value of minimum capital lease payments | 322 | 4 | 9 | 10 | 299 |
| Operating leases[c] | 392 | 39 | 66 | 54 | 233 |
| Total lease obligations | $ 714 | $ 43 | $ 75 | $ 64 | $ 532 |
| **UE:** | | | | | |
| Capital lease payments[b] | $ 717 | $ 32 | $ 65 | $ 65 | $ 555 |
| Less amount representing interest | 395 | 28 | 56 | 55 | 256 |
| Present value of minimum capital lease payments | 322 | 4 | 9 | 10 | 299 |
| Operating leases[c] | 174 | 15 | 28 | 25 | 106 |
| Total lease obligations | $ 496 | $ 19 | $ 37 | $ 35 | $ 405 |

| | Total | Less than 1 Year | 1 - 3 Years | 3 - 5 Years | After 5 Years |
|---|---|---|---|---|---|
| **CIPS:** | | | | | |
| Operating leases[c] | $ 2 | $ - | $ 1 | $ 1 | $ - |
| **Genco:** | | | | | |
| Operating leases[c] | $ 143 | $ 9 | $ 17 | $ 17 | $ 100 |
| **CILCORP and CILCO:** | | | | | |
| Operating leases[c] | $ 18 | $ 1 | $ 3 | $ 2 | $ 12 |
| **IP:** | | | | | |
| Operating leases[c] | $ 8 | $ 3 | $ 4 | $ 1 | $ - |

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

(b) See Properties under Part I, Item 2 of this report for further 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 amount because that period is indefinite.

We lease various facilities, office equipment, plant equipment, and rail cars under operating leases. We also have capital leases relating to UE's Peno Creek and Audrain County CT facilities. The following table presents total rental expense, included in other operations and maintenance expenses, for the years ended December 31, 2008, 2007 and 2006:

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Ameren[a] | $ 19 | $ 15 | $ 15 |
| UE | 20 | 19 | 20 |
| CIPS | 9 | 9 | 9 |
| Genco | 2 | 2 | 2 |
| CILCORP and CILCO | 7 | 7 | 6 |
| IP | 13 | 12 | 11 |

(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, and nuclear fuel. We also have entered into various long-term commitments for the purchase of electricity and natural gas for distribution. The following table presents the estimated fuel, electric capacity, and natural gas commitments at December 31, 2008. In addition, the following table presents in the Other column minimum purchase commitments for heavy forgings contracts related to a potential second nuclear unit, meter reading contracts, and an Ameren tax credit obligation. Ameren's tax credit obligation is a $75 million note payable issued for an investment in a low-income real estate development partnership to acquire New Markets Tax Credits. This note payable was netted against the related investment in Other Assets at December 31, 2008, as Ameren has a legally enforceable right to offset it under FIN 39.

| | Coal | Gas | Nuclear | Electric Capacity | Other | Total |
|---|---|---|---|---|---|---|
| **Ameren:[a]** | | | | | | |
| 2009 | $ 728 | $ 486 | $ 68 | $ 14 | $ 63 | $ 1,359 |
| 2010 | 841 | 399 | 75 | - | 89 | 1,404 |
| 2011 | 652 | 268 | 53 | - | 79 | 1,052 |
| 2012 | 440 | 176 | 67 | - | 79 | 762 |
| 2013 | 31 | 82 | 59 | - | 40 | 212 |
| Thereafter[b] | - | 173 | 173 | - | 292 | 638 |
| Total | $ 2,692 | $ 1,584 | $ 495 | $ 14 | $ 642 | $ 5,427 |
| **UE:** | | | | | | |
| 2009 | $ 393 | $ 80 | $ 68 | $ 14 | $ 31 | $ 586 |
| 2010 | 429 | 67 | 75 | - | 57 | 628 |
| 2011 | 313 | 47 | 53 | - | 46 | 459 |
| 2012 | 136 | 32 | 67 | - | 46 | 281 |
| 2013 | - | 23 | 59 | - | 24 | 106 |
| Thereafter[b] | - | 38 | 173 | - | 168 | 379 |
| Total | $ 1,271 | $ 287 | $ 495 | $ 14 | $ 372 | $ 2,439 |
| **CIPS:** | | | | | | |
| 2009 | $ - | $ 106 | $ - | $ (c) | $ 4 | $ 110 |
| 2010 | - | 71 | - | - | 2 | 73 |
| 2011 | - | 60 | - | - | 2 | 62 |
| 2012 | - | 44 | - | - | 2 | 46 |
| 2013 | - | 30 | - | - | 2 | 32 |
| Thereafter[b] | - | 28 | - | - | 18 | 46 |
| Total | $ - | $ 339 | $ - | $ - | $ 30 | $ 369 |

| | Coal | Gas | Nuclear | Electric Capacity | Other | Total |
|---|---|---|---|---|---|---|
| **Genco:** | | | | | | |
| 2009 | $ 134 | $ 10 | $ - | $ - | $ - | $ 144 |
| 2010 | 185 | 8 | - | - | - | 193 |
| 2011 | 129 | 8 | - | - | - | 137 |
| 2012 | 112 | 5 | - | - | - | 117 |
| 2013 | - | 3 | - | - | - | 3 |
| Thereafter[b] | - | 8 | - | - | - | 8 |
| Total | $ 560 | $ 42 | $ - | $ - | $ - | $ 602 |
| **CILCORP and CILCO:** | | | | | | |
| 2009 | $ 62 | $ 113 | $ - | $ (c) | $ 3 | $ 178 |
| 2010 | 84 | 93 | - | - | 3 | 180 |
| 2011 | 85 | 64 | - | - | 3 | 152 |
| 2012 | 79 | 40 | - | - | 3 | 122 |
| 2013 | 31 | 15 | - | - | 3 | 49 |
| Thereafter[b] | - | 91 | - | - | 25 | 116 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total | $ 341 | $ 416 | $ - | $ - | $ 40 | $ 797 |
| **IP:** | | | | | | |
| 2009 | $ - | $ 162 | $ - | $ (c) | $ 11 | $ 173 |
| 2010 | - | 158 | - | - | 10 | 168 |
| 2011 | - | 88 | - | - | 11 | 99 |
| 2012 | - | 54 | - | - | 11 | 65 |
| 2013 | - | 11 | - | - | 11 | 22 |
| Thereafter(b) | - | 8 | - | - | 81 | 89 |
| Total | $ - | $ 481 | $ - | $ - | $ 135 | $ 616 |

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Commitments for natural gas and nuclear fuel are until 2021 and 2020, respectively.
(c) At December 31, 2008, less than $1 million of electric capacity contracts were executed for the Ameren Illinois Utilities for 2009 with approximately 33% of the capacity resources dedicated to CIPS, 17% to CILCO, and 50% to IP. For 2009, approximately one-third of the Ameren Illinois Utilities capacity was obtained through the Illinois power procurement auction. The IPA plans to go forward with RFPs to purchase capacity for the Ameren Illinois Utilities during the first half of 2009. See below for additional information.

*Ameren Illinois Utilities' Purchased Power Agreements*

Commencing 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.

One-third of the Ameren Illinois Utilities' supply contracts that served the load needs of their fixed-price residential and small commercial customers, and all of the supply contracts that served large commercial and industrial customers, expired on May 31, 2008. The Ameren Illinois Utilities used RFP processes in early 2008 to replace these expired supply contracts, pursuant to the Illinois electric settlement agreement. Specifically, the Ameren Illinois Utilities used RFPs to procure energy swaps, capacity, and renewable energy credits for the period June 1, 2008, through May 31, 2009. The Ameren Illinois Utilities contracted to purchase approximately two million megawatthours of energy swaps at an average price of $60 per megawatthour. As a result of a capacity RFP, the Ameren Illinois Utilities contracted to purchase about 1,800 megawatts of capacity at an average price of $50 per MW-day. A renewable energy credits RFP resulted in the Ameren Illinois Utilities contracting to purchase 415,000 credits at an average price of $17 per credit.

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 Ending** | |
|---|---|---|
| | **May 31, 2009** | **May 31, 2010** |
| **Term** | **29 Months** | **41 Months** |
| CIPS' load in megawatts(a) | 639 | 639 |
| CILCO's load in megawatts(a) | 328 | 328 |
| IP's load in megawatts(a) | 928 | 928 |
| Total load in megawatts(a) | 1,895 | 1,895 |
| Cost per megawatthour | $ 64.75 | $ 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.

*Illinois Electric Settlement Agreement*

The Illinois electric settlement agreement provides $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 will come from 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, 2008:

| | Ameren | CIPS | CILCO (Illinois Regulated) | IP | Genco | CILCO (AERG) |
|---|---|---|---|---|---|---|
| 2009[a] | $ 26.6 | $ 3.9 | $ 1.9 | $ 5.1 | $ 10.8 | $ 4.9 |
| 2010[a] | 1.9 | 0.3 | 0.1 | 0.4 | 0.8 | 0.3 |
| Total | $ 28.5 | $ 4.2 | $ 2.0 | $ 5.5 | $ 11.6 | $ 5.2 |

(a) Estimated.

Also as part of the 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 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 plants, 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 and water, protected and cultural resources (such as wetlands, endangered species, and archeological and historical resources), and chemical and waste handling. Our activities often require complex and lengthy processes as we 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, including Missouri and Illinois where our generating facilities are located, and the District of Columbia to participate in cap-and-trade programs to reduce annual $SO_2$ emissions, annual $NO_x$ emissions, and ozone season $NO_x$ emissions. The cap-and-trade program for both annual and ozone season $NO_x$ emissions went into effect on January 1, 2009. The $SO_2$ emissions cap-and-trade program 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 maximum available control technology requirements under the Clean Air Act. The EPA and a group representing the electric utility industry filed petitions for rehearing; however, the court denied those petitions in May 2008. A group representing the electric utility industry and the EPA both filed petitions for review of the U.S. Court of Appeals decision with the U.S. Supreme Court in September 2008 and October 2008, respectively. In February 2009, the EPA withdrew its petition to the U.S. Supreme Court. In February 2009, the U.S. Supreme Court denied the 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. The standard is expected to be available in draft form by mid to late 2009, and compliance is expected to be required in the 2013 to 2015 timeframe.

We are currently evaluating the impact that the court decision will have on our environmental compliance strategy. We are unable to predict the outcome of this legal proceeding, the actions the EPA or U.S. Congress may take in response to the court decision, or the timing of such actions. We also cannot predict at this time the ultimate impact the court decision and resulting regulatory actions will have on our estimated capital costs for compliance with 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 state of Missouri has adopted state 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 30% and $SO_2$ emissions 75% by 2015. As a result of the Missouri rules, UE will manage allowances and install pollution control equipment. Missouri also adopted state rules to implement the federal Clean Air Mercury Rule. However, those state 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. Under the MPS, 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. To comply with the rule, Genco, CILCO (AERG) and EEI have begun putting into service equipment designed to reduce mercury emissions. This rule, when fully implemented, is expected to reduce mercury emissions 90%, $NO_x$ emissions 50%, and $SO_2$ emissions 70% by 2015 in Illinois. As a result of the Illinois rules, Genco, AERG and EEI will need to procure allowances and install 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.

In October 2008, Genco, CILCO (AERG) and EEI submitted a request for a variance from the MPS to the Illinois Pollution Control Board. In preparing this request, Genco, CILCO (AERG) and EEI worked with the Illinois EPA and agreed to the installation of more stringent $SO_2$ and $NO_x$ controls at various stages between 2010 and 2020 in order to make the variance proposal "environmentally neutral." In January 2009, the Illinois Pollution Control Board denied the variance request on procedural grounds. Genco, CILCO (AERG) and EEI filed a motion for reconsideration in February 2009. With the Illinois EPA's concurrence, they now seek to amend the MPS within a pending rulemaking pertaining to technical amendments of the underlying mercury regulations. Revisions to the MPS within that rulemaking will require Illinois Pollution Control Board approval. If approved, this variance or rule amendment would allow Genco to defer approximately $375 million of environmental capital expenditures from the 2009-2012 timeframe to the 2013-2015 timeframe. This amount is reduced from the $500 million disclosed in Genco's Quarterly Report on Form 10-Q for the period ended September 30, 2008, because of revisions to the size and timing of projected environmental capital expenditures if no variance is granted. A decision is expected in 2009.

In March 2008, the EPA finalized regulations that will lower the ambient standard for ozone. States must submit their nonattainment plans in March 2009. A final action by the EPA to designate areas as nonattainment 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 the future state implementation plans. At this time, we are unable to determine the impact such state actions would have on our results of operations, financial position, or liquidity.

The table below presents estimated capital costs that are based on current technology, to comply with the federal Clean Air Interstate Rule and related state implementation plans through 2018, as well as federal ambient air quality standards including ozone and fine particulates, and the federal Clean Air Visibility rule. The estimates described below could change depending upon additional federal or state requirements, the requirements under a mercury MACT standard, whether the variance or rule amendment request with respect to the Illinois MPS discussed above is granted, new technology, variations in costs of material or labor, or alternative compliance strategies, among other reasons. 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.

| | 2009 | 2010 - 2013 | 2014 - 2018 | Total |
|---|---|---|---|---|
| UE[a] | $ 100 | $525 - $655 | $1,530 - $1,885 | $2,155 - $2,640 |
| Genco | 230 | 875 - 1,085 | 95 - 125 | 1,200 - 1,440 |
| CILCO | 55 | 365 - 455 | 60 - 80 | 480 - 590 |
| EEI | 15 | 120 - 155 | 530 - 660 | 665 - 830 |
| Ameren | $ 400 | $1,885 - $2,350 | $2,215 - $2,750 | $4,500 - $5,500 |

(a) UE's expenditures are expected to be recoverable in rates over time.

*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. If additional allowances are needed for new generating facilities, they can be purchased from facilities that have excess allowances or from allowance banks. In addition, the Illinois rules to implement the federal Clean Air Interstate Rule include an allowance set aside for new generating facilities. 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 carried as intangible assets as of December 31, 2008.

UE, Genco, CILCO and EEI expect to use a substantial portion of the $SO_2$ 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 $SO_2$ that is 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, 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. Both sets of allowances for the years 2009 through 2014 were issued by the Missouri Department of Natural Resources in December 2007. Allocations for UE's Missouri generating facilities 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. Both sets of allowances for the years 2009 through 2011 were issued by the Illinois EPA in April 2008.

Allocations for UE's, Genco's, AERG's, and EEI's Illinois generating facilities were 90, 3,442, 1,368, and 1,758 tons per ozone season, respectively, and 93, 8,300, 3,418, and 4,564 tons annually.

*Global Climate*

Future initiatives regarding greenhouse gas emissions and global warming are subject to active consideration in the U.S. Congress. In October 2008, the U.S. House of Representatives, Energy and Commerce Committee, Subcommittee on Energy and Air Quality issued a "discussion draft" of climate legislation, which proposed establishing an economy-wide cap-and-trade program. The overarching goal of such legislation is to reduce greenhouse gas emissions to a level that is 6% below 2005 levels by 2020 and 80% below 2005 levels by the year 2050. In addition, new leadership in the Energy and Commerce Committee is considering aggressive climate legislation.

President Obama supports an economy-wide cap-and- trade greenhouse gas reduction program that would reduce emissions to 1990 levels by 2020 and to 80% below 1990 levels by 2050. President Obama has also indicated support for auctioning 100% of the emission allowances to be distributed under the legislation. Although we cannot predict the date of enactment or the requirements of any global warming legislation, it is likely that some form of federal greenhouse gas legislation will become law during President Obama's administration.

Potential impacts from proposed legislation could vary, depending upon proposed $CO_2$ emission limits, the timing of implementation of those limits, the method of allocating allowances, and provisions for cost containment measures, such as a "safety valve" that provides a ceiling price for emission allowance purchases. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies among our generating facilities, but coal-fired power plants are significant sources of $CO_2$, a principal greenhouse gas. Ameren's current analysis shows that under some policy scenarios being considered in the U.S. Congress, household costs and rates for electricity could rise significantly. The burden could fall particularly hard on electricity consumers and the Midwest economy 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 electric generation also could affect the cost of heating for our utility customers and many industrial processes. Under some policy scenarios being considered by Congress, 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.

Future initiatives regarding greenhouse gas emissions and global warming may also be subject to the activities 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. It is expected that the advisory group to the Midwest governors will provide recommendations on the design of a greenhouse gas reduction program by the third quarter of 2009. However, it is uncertain whether legislation to implement the recommendations will be implemented or passed by any of the states, including Illinois.

With regard to greenhouse gas regulation under existing law, in April 2007, the U.S. Supreme Court issued a decision 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 was a result of a Bush Administration ruling denying a waiver request by the state of California to implement such regulations. The Supreme Court sent the case back to the EPA, which must conduct a rulemaking process to determine whether greenhouse gas emissions contribute to climate change "which may reasonably be anticipated to endanger public health or welfare." In July 2008, the EPA issued an advance notice of public rulemaking (ANPR) in response to the U.S. Supreme Court's directive. The ANPR solicited public comments on the benefits and ramifications of regulating greenhouse gases under the Clean Air Act, and that rulemaking has not been completed. On February 12, 2009, the EPA announced its intent to reconsider the decision under the Bush Administration denying the waiver to the state of California for regulating $CO_2$ emissions from automobiles. On February 17, 2009, the EPA also granted a petition for reconsideration filed by the Sierra Club to reexamine a December 2008 Bush Administration ruling that $CO_2$ should not be regulated under the Clean Air Act when issuing construction permits for power plants. These EPA actions will factor into the rulemaking process on the ANPR and could ultimately lead to regulation of $CO_2$ from power plants.

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. 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. 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, or liquidity.

Ameren has taken actions to address the global climate issue. These include:

- seeking partners to develop wind energy for our generation portfolio;
- participating in DOE-sponsored research into the feasibility of sequestering $CO_2$ underground in the Illinois basin, the Plains sequestration partnership, and a Missouri sequestration project to be conducted in Southwest Missouri;
- increasing the operating efficiency and capacity of our nuclear and hydroelectric plants to provide more energy to offset fossil generation;
- participating in the PowerTree Carbon Company, LLC, whose purpose is to reforest acreage in the lower Mississippi valley to sequester carbon;
- using coal combustion byproducts as a direct replacement for cement, thereby reducing carbon emissions at cement kilns;
- participating in a DOE and state of Missouri Department of Natural Resources project evaluating Missouri wind resources for the next generation of wind turbines;
- funding a project investigating opportunities to reduce nitrous oxide ($N_2O$), a potent greenhouse gas from agricultural usage, and tracking those reductions;
- participating in the Illinois Clean Energy Community Foundation, a program that supports energy efficiency, promotes renewable energy, and provides educational opportunities;
- establishing Pure Power, UE's voluntary renewable energy program that allows UE's electric customers to support development of wind farms

and other renewable energy facilities in the Midwest;

- purchasing Renewable Energy Credits, as when the Ameren Illinois Utilities purchased 415,000 renewable energy credits in April 2008; and
- participating in funding the new Consortium for Clean Coal Utilization research center at Washington University, which will investigate clean coal technologies, such as oxy-fuel combustion and $CO_2$ capture and storage.

The impact on us of future initiatives related to greenhouse gas emissions and global warming is unknown. Although compliance costs are unlikely in the near future, 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, or liquidity.

*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 us to install additional intake screens or 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 facilities. In January 2007, the U.S. Court of Appeals for the Second Circuit remanded many provisions of these rules to the EPA for revision. In April 2008, the U.S. Supreme Court agreed to hear an appeal of the lower court ruling. The U.S. Supreme Court heard the case in December 2008. The EPA is expected to reissue the rules early in 2009. Until a decision is issued by the Supreme Court and the new rules are adopted, and the studies on 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.

*New Source Review*

The EPA has been conducting an enforcement initiative to determine whether modifications at a number of coal-fired power plants owned by electric utilities in the United States are subject to New Source Review (NSR) requirements or New Source Performance Standards under the Clean Air Act. The EPA's inquiries focus on whether the best available emission control technology was or should have been used at such power plants when major maintenance or capital improvements were performed.

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 December 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. We are in the process of responding to this request. We are also currently in discussions with the EPA and the state of Illinois regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

In March 2008, Ameren received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act seeking detailed operating and maintenance history data with respect to UE's Labadie, Meramec, Rush Island, and Sioux facilities. All of these facilities are coal-fired power plants. The information request required UE to provide responses to specific EPA questions regarding certain projects and maintenance activities in order to determine UE's compliance with state and federal regulatory requirements. UE is complying with this information request, but we are unable to predict the outcome of this matter.

Resolution of these matters could have a material adverse impact on the future results of operations, financial position, or 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.

*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 for

remediation costs associated with preexisting environmental contamination at the transferred sites.

As of December 31, 2008, CIPS, CILCO and IP owned or were otherwise responsible for several former MGP sites in Illinois. CIPS has 14, CILCO 4, and IP 25. All of these sites are in various stages of investigation, evaluation and remediation. Under its current schedule, Ameren anticipates that remediation at these sites should be completed by 2015. 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, and costs are subject to annual reconciliation review by the ICC. As of December 31, 2008, estimated obligations were: CIPS - $17 million to $29 million, CILCO - $8 million to $13 million, IP - $74 million to $143 million. CIPS, CILCO and IP recorded liabilities of $17 million, $8 million, and $74 million, respectively, to represent estimated minimum obligations, as no other amount within the range was a better estimate.

CIPS is also responsible for the cleanup of a former landfill in Coffeen, Illinois. As of December 31, 2008, CIPS estimated its 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, 2008, IP recorded a liability of $1 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 in Iowa. UE does not currently have in effect in Missouri a rate rider mechanism that permits remediation costs associated with MGP sites to be recovered from utility customers. See Note 2 - Rate and Regulatory Matters for information on a Missouri law enabling the MoPSC to put in place environmental cost recovery mechanisms for Missouri utilities. 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, 2008, UE estimated its obligation at $3 million to $4 million. UE recorded a liability of $3 million 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 electric sites in Missouri that have corporate cleanup liability, most as a result of federal agency mandates.

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.

Sauget Area 2 investigations overseen by the EPA are largely completed, and the results will be submitted to the EPA in June 2009. Following this submission, the EPA will ultimately select a remedy alternative and begin negotiations with various PRPs to implement it. Over the last several years, numerous other parties have joined the PRP group and 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, 2008, UE estimated its obligation at $1 million to $10 million. UE recorded a liability of $1 million to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In March 2008, the EPA issued an administrative order requesting that CIPS participate in a portion of an environmental cleanup of a site within Sauget Area 2 previously occupied by Clayton Chemical Company. CIPS was formerly a customer of Clayton Chemical Company, which before its dissolution was a recycler of waste solvents and oil. Other former customers of Clayton Chemical Company were issued similar orders by the EPA. Pursuant to that order, CIPS and three other PRPs agreed to install an engineered barrier on portions of the Clayton Chemical Company site. This work is expected to be concluded in the first quarter of 2009. As of December 31, 2008, CIPS recorded a liability of $0.25 million to represent its best estimate of its obligation for this site.

In July 2008, the EPA issued an administrative order to UE pertaining to a former coal tar distillery operated by Koppers Company or its predecessor and successor companies. UE is the current owner of the site but did not conduct any of the manufacturing operations involving coal tar or its byproducts. UE is currently in negotiations with other PRPs concerning the scope of future site investigations. As of December 31, 2008, UE estimated its obligation at $2 million to $5 million. UE recorded a liability of $2 million to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In December 2004, AERG submitted a comprehensive package 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. CILCORP and CILCO both have a liability of $1.9 million at December 31, 2008, on their Consolidated Balance Sheets for the estimated cost of the remediation effort, which involves treating and discharging recycle-system water in order to address these groundwater and

surface water issues.

In addition, 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 the impact these actions may have on our results of operations, financial position, or liquidity.

*Ash Ponds*

In December 2008, an ash pond dike failed at a non-Ameren owned utility company releasing approximately one billion gallons of coal ash slurry. The ash was deposited primarily over 300 acres, destroying three homes. As a result of this incident, there has been increased activity at both the state and federal level to examine the need for additional regulation of utility ash pond facilities and coal-combustion wastes. It is anticipated that some form of additional regulation concerning the integrity of ash ponds and the handling and disposal of coal combustion waste may be forthcoming within the next two years. At this time, we are unable to predict the outcome any such regulations might have on our results of operations, financial position, or liquidity.

*Polychlorinated Biphenyls Information Request*

Polychlorinated biphenyls (PCBs) are a blend of chemical compounds that were historically used in a variety of industrial products because of their chemical and thermal stability. In natural gas systems, PCBs were used as a compressor lubricant and a valve sealant before their sale for these applications was banned by the EPA in 1979. During the third quarter of 2007, the Ameren Illinois Utilities received requests from the Illinois attorney general and from the EPA for information regarding their experiences with PCBs in their gas distribution systems. The Ameren Illinois Utilities responded to these information requests.

The Ameren Illinois Utilities have evaluated their gas distribution systems for the presence of PCBs. They believe that the presence of PCBs is limited to discrete areas and is not widespread throughout their service territories. We cannot predict whether any further actions will be required on the part of the Ameren Illinois Utilities regarding this matter or what the ultimate outcome will be.

**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 has settled with FERC and the state of Missouri all issues associated with the December 2005 Taum Sauk incident. In addition, UE received approval from FERC to rebuild the upper reservoir at its Taum Sauk plant and has begun rebuilding the facility. The estimated cost to rebuild the upper reservoir is in the range of $480 million. UE expects the Taum Sauk plant to be out of service through early 2010.

In December 2006, 11 business owners filed a lawsuit regarding the Taum Sauk breach. The suit, which was filed in the Missouri Circuit Court of Reynolds County and remains pending, contains allegations of negligence, violations of the Missouri Clean Water Act, and various other statutory and common law claims. It seeks damages relating to business losses, lost profit, and unspecified punitive damages. UE has filed a motion to dismiss the lawsuit, arguing that Missouri law does not permit the plaintiffs to recover purely economic losses under theories of negligence and strict liability. This motion is currently pending.

In December 2008, the Department of the Army, Corps of Engineers filed a lawsuit regarding the Taum Sauk breach. The suit, which was filed in the U.S. District Court in Cape Girardeau, Missouri, and remains pending, claims that Clearwater Lake in southeast Missouri was damaged by sediment from the Taum Sauk breach. This litigation is in its early stages, and we are evaluating the merits of the allegations. We are unable to predict the timing or outcome of this litigation, or its possible effect on UE's results of operations, financial position, or liquidity.

At this time, UE believes that substantially all damages and liabilities caused by the breach, including costs related to the settlement agreement with the state of Missouri, the cost of rebuilding the plant, and the cost of replacement power, up to $8 million annually, will be covered by insurance. Insurance will 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 reservoir, will range from $200 million to $220 million. As of December 31, 2008, UE had paid $181 million, including costs resulting from the FERC-approved stipulation and consent agreement. UE accrued a $18 million liability while expensing $33 million and recording a $166 million receivable due from insurance companies. As of December 31, 2008, UE had received $85 million from insurance companies, which

reduced the insurance receivable balance to $81 million.

As of December 31, 2008, UE had recorded a $332 million receivable due from insurance companies related to the rebuilding of the facility and the reimbursement of replacement power costs. As of December 31, 2008, UE had received $158 million from insurance companies, which reduced the insurance receivable balance as of December 31, 2008, to $174 million.

Under UE's insurance policies, all claims by or against UE are subject to review by its insurance carriers.

Until litigation has been resolved and the insurance review is completed, among other things, we are unable to determine the total impact the breach may have on Ameren's and UE's results of operations, financial position, or liquidity beyond those amounts already recognized.

**Mechanics' Liens**

In November 2007, the primary subcontractor on a 2007 maintenance outage at AERG's Duck Creek facility filed a complaint for foreclosure of its mechanic's lien of $19 million plus interest against AERG. That action was filed in the Circuit Court of Fulton County, Illinois. Subsequently, various second-tier subcontractors of the primary subcontractor also filed for foreclosure of their mechanics' lien claims against AERG in the Circuit Court of Fulton County, Illinois, in addition to filing their claims against the primary subcontractor. Approximately 13 mechanics' liens claiming $23 million plus interest in the aggregate were filed as of December 31, 2008, against AERG for labor or material for the 2007 maintenance outage. These claims were primarily based on additional work outside of the original contract scope. Effective as of December 17, 2008, AERG entered into a Settlement and Release Agreement with the primary contractor. It provides that in exchange for AERG's payment of $19 million to the primary contractor, the primary contractor will, among other things, release Ameren from any existing or future claims they may have, pay off and obtain full releases of all mechanics' liens filed against AERG and dismiss all mechanics' lien claims against AERG in the Fulton County litigation made by the primary subcontractor and all second-tier subcontractors', and indemnify, defend and hold AERG harmless from all such claims by these parties. The resolution of these liens and lawsuits did not have a material impact on CILCO's results of operations, financial position, or liquidity.

**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 161 parties are named in some pending cases and as few as six in others. However, in the cases pending as of December 31, 2008, the average number of parties was 68.

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, 2008:

| Specifically Named as Defendant | | | | | | |
|---|---|---|---|---|---|---|
| Ameren | UE | CIPS | Genco | CILCO | IP | Total[a] |
| 3 | 25 | 31 | - | 10 | 36 | 67 |

(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, 2008, six 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.

IP has a tariff rider to recover the costs of asbestos-related litigation claims, subject to the following terms. Beginning in 2007, 90% of cash expenditures in excess of the amount included in base electric rates are recoverable by IP from a trust fund established by IP. At December 31, 2008, the trust fund balance was $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 is not expected to have its permanent storage facility for spent fuel available before 2020. 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.

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. UE intends to submit a license extension application with the NRC to extend its Callaway nuclear plant's operating license to 2044. It is assumed that the Callaway nuclear plant site will be decommissioned based on the immediate dismantlement method and removal 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. See Note 1 - Summary of Significant Accounting Policies for additional information on asset retirement obligations. Decommissioning costs are charged to the costs of service used to establish electric rates for UE's customers. These costs amounted to $7 million in each of the years 2008, 2007 and 2006. 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 study was filed in September 2008. The 2008 study included the minor tritium contamination discovered on the Callaway nuclear plant site, which did not result in a significant increase in the decommissioning cost estimate. 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 and UE's Consolidated Balance Sheets. This amount is legally restricted. It 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 and to a regulatory asset or regulatory liability, as appropriate.

See Note 2 - Rate and Regulatory Matters for information on the COLA filed by UE with the NRC for a potential new nuclear unit and Note 9 - Nuclear Decommissioning Trust Fund Investments.

**NOTE 17 - SEGMENT INFORMATION**

Ameren has three reportable segments: Missouri Regulated, Illinois Regulated, and Non-rate-regulated 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) and other non-rate-regulated activities, which are in Other. 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. The Non-rate-regulated Generation segment for Ameren consists primarily of the operations or activities of Genco, the CILCORP parent company, AERG, EEI, and Marketing Company. The category called Other primarily includes Ameren parent company activities and the leasing activities of CILCORP, AERG, Resources Company, and CIPSCO Investment Company. CIPSCO Investment Company was eliminated on March 31, 2008, through an internal reorganization.

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 and other non-rate-regulated activities, which are included in Other.

CILCORP and CILCO have two reportable segments: Illinois Regulated and Non-rate-regulated Generation. The Illinois Regulated segment for

CILCORP and CILCO consists of the regulated electric and gas transmission and distribution businesses of CILCO. The Non-rate-regulated Generation segment for CILCORP and CILCO consists of the generation business of AERG. For CILCORP and CILCO, Other comprises leveraged lease investments, parent company activity, and minor activities not reported in the Illinois Regulated or Non-rate-regulated Generation segments for CILCORP.

The following tables present information about the reported revenues and specified items included in net income of Ameren, UE, CILCORP, and CILCO for the years ended December 31, 2008, 2007 and 2006, and total assets as of December 31, 2008, 2007 and 2006.

**Ameren**

| | Missouri Regulated | Illinois Regulated | Non-rate-regulated Generation | Other | Intersegment Eliminations | Consolidated |
|---|---|---|---|---|---|---|
| **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 expense | **193** | **144** | **99** | **44** | **(40)** | **440** |
| Income taxes (benefit) | **134** | **16** | **217** | **(40)** | **-** | **327** |
| Net income (loss)[a] | **234** | **32** | **352** | **(13)** | **-** | **605** |
| Capital expenditures | **874** | **359** | **611** | **52** | **-** | **1,896** |
| Total assets[b] | **11,524** | **7,079** | **4,622** | **1,227** | **(1,795)** | **22,657** |
| **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 expense | 194 | 132 | 107 | 29 | (39) | 423 |
| Income taxes (benefit) | 143 | 25 | 182 | (20) | - | 330 |
| Net income[a] | 281 | 47 | 281 | 9 | - | 618 |
| Capital expenditures | 625 | 321 | 395 | 40 | - | 1,381 |
| Total assets[b] | 10,852 | 6,385 | 4,027 | 965 | (1,501) | 20,728 |
| **2006** | | | | | | |
| External revenues | $ 2,584 | $ 3,338 | $ 926 | $ 47 | $ - | $ 6,895 |
| Intersegment revenues | 227 | 15 | 788 | 27 | (1,057) | - |
| Depreciation and amortization | 335 | 192 | 106 | 28 | - | 661 |
| Interest and dividend income | 33 | 20 | 1 | 34 | (50) | 38 |
| Interest expense | 171 | 95 | 103 | 29 | (48) | 350 |
| Income taxes (benefit) | 184 | 65 | 78 | (43) | - | 284 |
| Net income[a] | 267 | 115 | 138 | 27 | - | 547 |
| Capital expenditures | 782 | 314 | 160 | 28 | - | 1,284 |
| Total assets[b] | 10,254 | 6,280 | 3,612 | 1,161 | (1,672) | 19,635 |

(a) Represents net income available to common stockholders; 100% of CILCO's preferred stock dividends are included in the Illinois Regulated segment.
(b) Total assets for Illinois Regulated included an allocation of goodwill and other purchase accounting amounts related to CILCO that are recorded at CILCORP (parent company).

**UE**

| | Missouri Regulated | Other[a] | Consolidated UE |
|---|---|---|---|
| **2008** | | | |
| Revenues | **$ 2,960** | **$ -** | **$ 2,960** |
| Depreciation and amortization | **329** | **-** | **329** |
| Interest expense | **193** | **-** | **193** |
| Income taxes | **134** | **-** | **134** |
| Net income[b] | **234** | **11** | **245** |
| Capital expenditures | **874** | **-** | **874** |
| Total assets | **11,524** | **-** | **11,524** |

| | Missouri Regulated | Other[a] | Consolidated UE |
|---|---|---|---|

| | | | |
|---|---|---|---|
| **2007** | | | |
| Revenues | $ 2,961 | $ - | $ 2,961 |
| Depreciation and amortization | 333 | - | 333 |
| Interest expense | 194 | - | 194 |
| Income taxes (benefit) | 143 | (3) | 140 |
| Net income(b) | 281 | 55 | 336 |
| Capital expenditures | 625 | - | 625 |
| Total assets | 10,852 | 51 | 10,903 |
| **2006** | | | |
| Revenues | $ 2,811 | $ 12 | $ 2,823 |
| Depreciation and amortization | 335 | - | 335 |
| Interest expense | 171 | - | 171 |
| Income taxes | 184 | - | 184 |
| Net income(b) | 267 | 76 | 343 |
| Capital expenditures | 782 | - | 782 |
| Total assets | 10,254 | 36 | 10,290 |

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

## CILCORP

| | Illinois Regulated | Non-rate-regulated Generation | Other | Intersegment Eliminations | Consolidated CILCORP |
|---|---|---|---|---|---|
| **2008** | | | | | |
| External revenues | **$ 805** | **$ 342** | **$ -** | **$ -** | **$ 1,147** |
| Intersegment revenues | **3** | **-** | **-** | **(3)** | **-** |
| Depreciation and amortization | **50** | **31** | **-** | **-** | **81** |
| Interest expense | **16** | **39** | **-** | **-** | **55** |
| Income taxes | **5** | **14** | **-** | **-** | **19** |
| Net income (loss)(a) | **16** | **27** | **(1)** | **-** | **42** |
| Capital expenditures | **61** | **258** | **-** | **-** | **319** |
| Total assets(b) | **1,402** | **1,680** | **2** | **(219)** | **2,865** |
| **2007** | | | | | |
| External revenues | $ 732 | $ 279 | $ - | $ - | $ 1,011 |
| Intersegment revenues | - | 4 | - | (4) | - |
| Depreciation and amortization | 54 | 24 | - | - | 78 |
| Interest expense | 18 | 46 | - | - | 64 |
| Income taxes | - | 21 | - | - | 21 |
| Net income(a) | 9 | 38 | - | - | 47 |
| Capital expenditures | 64 | 190 | - | - | 254 |
| Total assets(b) | 1,202 | 1,455 | 1 | (199) | 2,459 |
| **2006** | | | | | |
| External revenues | $ 713 | $ 34 | $ - | $ - | $ 747 |
| Intersegment revenues | - | 181 | - | (181) | - |
| Depreciation and amortization | 53 | 22 | - | - | 75 |
| Interest expense | 15 | 37 | - | - | 52 |
| Income taxes (benefit) | 12 | (19) | (4) | - | (11) |
| Net income (loss)(a) | 25 | (3) | (3) | - | 19 |
| Capital expenditures | 53 | 66 | - | - | 119 |
| Total assets(b) | 1,217 | 1,246 | 4 | (217) | 2,250 |

(a) Represents net income available to the common stockholders (Ameren); 100% of CILCO's preferred stock dividends are included in the Illinois Regulated segment.
(b) Total assets for Illinois Regulated and Non-rate-regulated Generation include an allocation of goodwill and other purchase accounting amounts related to CILCO that are recorded at CILCORP (parent company).

## CILCO

| | Illinois Regulated | Non-rate-regulated Generation | Other | Intersegment Eliminations | Consolidated CILCO |
|---|---|---|---|---|---|
| **2008** | | | | | |
| External revenues | **$ 805** | **$ 342** | **$ -** | **$ -** | **$ 1,147** |

| | | | | | |
|---|---|---|---|---|---|
| Intersegment revenues | **3** | **-** | **-** | **(3)** | **-** |
| Depreciation and amortization | **50** | **27** | **-** | **-** | **77** |
| Interest expense | **16** | **5** | **-** | **-** | **21** |

| | Illinois Regulated | Non-rate-regulated Generation | Other | Intersegment Eliminations | Consolidated CILCO |
|---|---|---|---|---|---|
| Income taxes | **5** | **34** | **-** | **-** | **39** |
| Net income[a] | **16** | **52** | **-** | **-** | **68** |
| Capital expenditures | **61** | **258** | **-** | **-** | **319** |
| Total assets | **1,212** | **1,081** | **-** | **1** | **2,294** |
| **2007** | | | | | |
| External revenues | $ 732 | $ 279 | $ - | $ - | $ 1,011 |
| Intersegment revenues | - | 4 | - | (4) | - |
| Depreciation and amortization | 54 | 19 | - | - | 73 |
| Interest expense | 18 | 8 | 1 | - | 27 |
| Income taxes | - | 39 | - | - | 39 |
| Net income[a] | 9 | 65 | - | - | 74 |
| Capital expenditures | 64 | 190 | - | - | 254 |
| Total assets | 1,012 | 859 | - | (9) | 1,862 |
| **2006** | | | | | |
| External revenues | $ 713 | $ 34 | $ - | $ - | $ 747 |
| Intersegment revenues | - | 181 | - | (181) | - |
| Depreciation and amortization | 53 | 17 | - | - | 70 |
| Interest expense | 15 | 3 | - | - | 18 |
| Income taxes (benefit) | 12 | 2 | (4) | - | 10 |
| Net income (loss)[a] | 25 | 23 | (3) | - | 45 |
| Capital expenditures | 53 | 66 | - | - | 119 |
| Total assets | 1,029 | 642 | 1 | (22) | 1,650 |

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

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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, 2008:

| | |
|---|---|
| Cash and Cash Equivalents at End of Period | $ 136,855 |
| Related amounts on the Balance Sheet: | |
| Line 35 – Cash | $ 135,655 |
| Line 37 – Working Fund | 1,200 |
| Line 38 – Temp Cash Investments | - |
| | $ 136,855 |

Amount of interest paid (net of amounts capitalized) = $19,246,321

Amount of income taxes paid, net = ($7,706,293)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

| Line No. | Item<br>(a) | Unrealized Gains and Losses on Available-for-Sale Securities<br>(b) | Minimum Pension Liability adjustment (net amount)<br>(c) | Foreign Currency Hedges<br>(d) | Other Adjustments<br>(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 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 Futures and Options (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 | | 3,655,449 | 3,655,449 | | |
| 2 | | ( 2,250,921) | ( 2,250,921) | | |
| 3 | | ( 812,576) | ( 812,576) | | |
| 4 | | ( 3,063,497) | ( 3,063,497) | 75,983,503 | 72,920,006 |
| 5 | | 591,952 | 591,952 | | |
| 6 | | 591,952 | 591,952 | | |
| 7 | | ( 784,864) | ( 784,864) | | |
| 8 | | 192,912 | 192,912 | | |
| 9 | | ( 591,952) | ( 591,952) | 69,638,345 | 69,046,393 |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 (f) 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) | 1,458,052,611 | 953,929,029 |
| 4 | Property Under Capital Leases | | |
| 5 | Plant Purchased or Sold | | |
| 6 | Completed Construction not Classified | | |
| 7 | Experimental Plant Unclassified | | |
| 8 | Total (3 thru 7) | 1,458,052,611 | 953,929,029 |
| 9 | Leased to Others | | |
| 10 | Held for Future Use | 133,638 | 133,638 |
| 11 | Construction Work in Progress | 12,207,611 | 10,914,369 |
| 12 | Acquisition Adjustments | | |
| 13 | Total Utility Plant (8 thru 12) | 1,470,393,860 | 964,977,036 |
| 14 | Accum Prov for Depr, Amort, & Depl | 914,934,143 | 550,203,572 |
| 15 | Net Utility Plant (13 less 14) | 555,459,717 | 414,773,464 |
| 16 | Detail of Accum Prov for Depr, Amort & Depl | | |
| 17 | In Service: | | |
| 18 | Depreciation | 914,784,264 | 550,192,910 |
| 19 | Amort & Depl of Producing Nat Gas Land/Land Right | | |
| 20 | Amort of Underground Storage Land/Land Rights | | |
| 21 | Amort of Other Utility Plant | 149,879 | 10,662 |
| 22 | Total In Service (18 thru 21) | 914,934,143 | 550,203,572 |
| 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) | 914,934,143 | 550,203,572 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 |
| 504,123,582 | | | | | 3 |
| | | | | | 4 |
| | | | | | 5 |
| | | | | | 6 |
| | | | | | 7 |
| 504,123,582 | | | | | 8 |
| | | | | | 9 |
| | | | | | 10 |
| 1,293,242 | | | | | 11 |
| | | | | | 12 |
| 505,416,824 | | | | | 13 |
| 364,730,571 | | | | | 14 |
| 140,686,253 | | | | | 15 |
| | | | | | 16 |
| | | | | | 17 |
| 364,591,354 | | | | | 18 |
| | | | | | 19 |
| | | | | | 20 |
| 139,217 | | | | | 21 |
| 364,730,571 | | | | | 22 |
| | | | | | 23 |
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| | | | | | 31 |
| | | | | | 32 |
| 364,730,571 | | | | | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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) | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

| Changes during Year | | Balance End of Year (f) | Line No. |
|---|---|---|---|
| Amortization (d) | Other Reductions (Explain in a footnote) (e) | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 7,897 | 18,759 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 7,897 | 18,759 |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 4,919,187 | 3,490 |
| 49 | (352) Structures and Improvements | 5,376,025 | |
| 50 | (353) Station Equipment | 42,650,413 | 1,857,534 |
| 51 | (354) Towers and Fixtures | 16,245,898 | 405,918 |
| 52 | (355) Poles and Fixtures | 12,186,814 | 311,965 |
| 53 | (356) Overhead Conductors and Devices | 20,513,342 | 337,614 |
| 54 | (357) Underground Conduit | 234,658 | |
| 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) | 102,868,971 | 2,916,521 |
| 59 | 4. DISTRIBUTION PLANT | | |
| 60 | (360) Land and Land Rights | 3,026,481 | 110,616 |
| 61 | (361) Structures and Improvements | 7,207,736 | 15,900 |
| 62 | (362) Station Equipment | 103,874,885 | 6,992,789 |
| 63 | (363) Storage Battery Equipment | | |
| 64 | (364) Poles, Towers, and Fixtures | 153,349,998 | 6,697,292 |
| 65 | (365) Overhead Conductors and Devices | 138,542,946 | 6,882,939 |
| 66 | (366) Underground Conduit | 58,236,369 | 2,717,732 |
| 67 | (367) Underground Conductors and Devices | 132,729,849 | 6,756,273 |
| 68 | (368) Line Transformers | 83,743,218 | 3,379,079 |
| 69 | (369) Services | 55,243,003 | 3,083,464 |
| 70 | (370) Meters | 22,734,931 | 1,218,229 |
| 71 | (371) Installations on Customer Premises | | |
| 72 | (372) Leased Property on Customer Premises | | |
| 73 | (373) Street Lighting and Signal Systems | 12,243,111 | 708,249 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | | |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 770,932,527 | 38,562,562 |
| 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 | 841,077 | |
| 87 | (390) Structures and Improvements | 20,598,996 | 1,096,566 |
| 88 | (391) Office Furniture and Equipment | 3,539,989 | 460,579 |
| 89 | (392) Transportation Equipment | 13,321,033 | 1,996,988 |
| 90 | (393) Stores Equipment | 265,566 | 108,158 |
| 91 | (394) Tools, Shop and Garage Equipment | 3,640,215 | 181,529 |
| 92 | (395) Laboratory Equipment | 575,666 | 77,005 |
| 93 | (396) Power Operated Equipment | 1,437,356 | 331,657 |
| 94 | (397) Communication Equipment | 2,671,727 | 2,838,094 |
| 95 | (398) Miscellaneous Equipment | 24,294 | 1,269 |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 46,915,919 | 7,091,845 |
| 97 | (399) Other Tangible Property | | |
| 98 | (399.1) Asset Retirement Costs for General Plant | 225,378 | |
| 99 | TOTAL General Plant (Enter Total of lines 96, 97 and 98) | 47,141,297 | 7,091,845 |
| 100 | TOTAL (Accounts 101 and 106) | 920,950,692 | 48,589,687 |
| 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) | 920,950,692 | 48,589,687 |

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 |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 |
| | | | 4,922,677 | | 48 |
| | | | 5,376,025 | | 49 |
| | | | 44,507,947 | | 50 |
| | | | 16,651,816 | | 51 |
| | | | 12,498,779 | | 52 |
| 1,032 | | -1,134 | 20,848,790 | | 53 |
| | | 1,134 | 235,792 | | 54 |
| | | | 713,442 | | 55 |
| | | | 29,192 | | 56 |
| | | | | | 57 |
| 1,032 | | | 105,784,460 | | 58 |
| | | | | | 59 |
| | | | 3,137,097 | | 60 |
| | | -5,821 | 7,217,815 | | 61 |
| | | 1,317 | 110,868,991 | | 62 |
| | | 4,504 | 4,504 | | 63 |
| 353,251 | | | 159,694,039 | | 64 |
| 794,967 | | | 144,630,918 | | 65 |
| 66,046 | | | 60,888,055 | | 66 |
| 1,738,754 | | | 137,747,368 | | 67 |
| 629,576 | | 63,163 | 86,555,884 | | 68 |
| 7,560,969 | | | 50,765,498 | | 69 |
| 1,450,352 | | -1,254,780 | 21,248,028 | | 70 |
| | | | | | 71 |
| | | | | | 72 |
| 362,068 | | | 12,589,292 | | 73 |
| | | | | | 74 |
| 12,955,983 | | -1,191,617 | 795,347,489 | | 75 |
| | | | | | 76 |
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| | | | | | 84 |
| | | | | | 85 |
| 2,484 | | | 838,593 | | 86 |
| 74,582 | | -16,263 | 21,604,717 | | 87 |
| 230,141 | | | 3,770,427 | | 88 |
| 348,631 | | -214,088 | 14,755,302 | | 89 |
| | | | 373,724 | | 90 |
| 110,688 | | | 3,711,056 | | 91 |
| 65,535 | | | 587,136 | | 92 |
| 189,682 | | -19,971 | 1,559,360 | | 93 |
| 205,890 | | 15,237 | 5,319,168 | | 94 |
| | | | 25,563 | | 95 |
| 1,227,633 | | -235,085 | 52,545,046 | | 96 |
| | | | | | 97 |
| | | | 225,378 | | 98 |
| 1,227,633 | | -235,085 | 52,770,424 | | 99 |
| 14,184,648 | | -1,426,702 | 953,929,029 | | 100 |
| | | | | | 101 |
| | | | | | 102 |
| | | | | | 103 |
| 14,184,648 | | -1,426,702 | 953,929,029 | | 104 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | | | | |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | | 133,638 |
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| 21 | Other Property: | | | |
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| 45 | | | | |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 $100,000, whichever is less) may be grouped.

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | East Springfield - 3rd 138-34kV Transformer | 2,868,450 |
| 2 | San Jose Rail Switching Station - Network Upgrade | 1,634,706 |
| 3 | Capacitor Bank Program year 3 | 576,077 |
| 4 | Alta Road Rebuild - Phase 1 | 500,218 |
| 5 | Lincoln-Kickapoo 3 Rebuild | 398,226 |
| 6 | Duck Creek - Replace 345kV Breaker #4552 | 393,058 |
| 7 | Peoria General Office Building - Replace Curtain Wall | 388,491 |
| 8 | Mansfield 4 Reconductoring - Phase 2 | 353,581 |
| 9 | San Jose Rail Switching Station - Interconnection Customer Facility | 345,621 |
| 10 | Radnor 2 Rebuild | 334,133 |
| 11 | Lincoln-Heyworth 3 Rebuild | 322,806 |
| 12 | San Jose Rail-In-Out Tap-G515 | 273,061 |
| 13 | Salem - Sectionalize - L6972 | 223,335 |
| 14 | Bradley - Install Sectionalizing Setup | 211,281 |
| 15 | Lincoln-Limit 18 Rebuuild | 194,020 |
| 16 | Bush - Add Pilot Relays to 6959 | 179,166 |
| 17 | Sheridan - Add Pilot Relays to 6959 | 172,695 |
| 18 | Edwards - Add Pilot Relays to 6959 | 168,859 |
| 19 | Lincoln-McGrath 2 Rebuild | 161,907 |
| 20 | Northwoods Mall Cable Replacement | 158,266 |
| 21 | CILCO Road Tractor | 148,853 |
| 22 | Radnor 7 Reconductor | 138,994 |
| 23 | Fieldstone Subdivision | 136,151 |
| 24 | Tazewell - Replace 6975 and 6951 Relays | 131,646 |
| 25 | Allen - Install 69kV Auto Throw Over Scheme | 103,794 |
| 26 | Minor Projects | 396,974 |
| 27 | | |
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| 42 | | |
| 43 | TOTAL | 10,914,369 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 534,765,845 | 534,765,845 | | |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 30,535,637 | 30,535,637 | | |
| 4 | (403.1) Depreciation Expense for Asset Retirement Costs | | | | |
| 5 | (413) Exp. of Elec. Plt. Leas. to Others | | | | |
| 6 | Transportation Expenses-Clearing | 1,275,461 | 1,275,461 | | |
| 7 | Other Clearing Accounts | 146,039 | 146,039 | | |
| 8 | Other Accounts (Specify, details in footnote): | 280,193 | 280,193 | | |
| 9 | | | | | |
| 10 | TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9) | 32,237,330 | 32,237,330 | | |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | 14,184,648 | 14,184,648 | | |
| 13 | Cost of Removal | 2,427,378 | 2,427,378 | | |
| 14 | Salvage (Credit) | 210,712 | 210,712 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | 16,401,314 | 16,401,314 | | |
| 16 | Other Debit or Cr. Items (Describe, details in footnote): | -408,951 | -408,951 | | |
| 17 | Net Credit (See Page 219A) | | | | |
| 18 | Book Cost or Asset Retirement Costs Retired | | | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 550,192,910 | 550,192,910 | | |
| | **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 | 61,014,153 | 61,014,153 | | |
| 26 | Distribution | 460,998,343 | 460,998,343 | | |
| 27 | Regional Transmission and Market Operation | | | | |
| 28 | General | 28,180,414 | 28,180,414 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 550,192,910 | 550,192,910 | | |

FOOTNOTE DATA

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

Other Accounts shown on Page 219, Line 8

| | | |
|---|---|---|
| (1) Depreciation apportioned from electric | $ | 276,513 |
| (2) Asset Retirement Obligation charged to Account 182 | | 3,680 |
| Total Other Account on Page 219, Line 8 | $ | 280,193 |

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

Other debit or credit items shown on Page 219, Line 16

| | | |
|---|---|---|
| Electric Plant Transfers | $ | (408,951) |
| Total Other debit or credit items on Page 219, Line 16 | $ | (408,951) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | 384,897,590 |
| 2 | Equity in Undistributed Earnings | | | |
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| 41 | | | | |
| 42 | Total Cost of Account 123.1 $ 0 | | TOTAL | 384,897,590 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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. |
|---|---|---|---|---|
| 52,594,611 | | 437,492,201 | | 1 |
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| 52,594,611 | | 437,492,201 | | 42 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | 38,825 | 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) | 246,177 | 264,142 | Electric |
| 9 | Distribution Plant (Estimated) | 4,817,564 | 5,178,981 | Electric |
| 10 | Regional Transmission and Market Operation Plant (Estimated) | | | |
| 11 | Assigned to - Other (provide details in footnote) | 2,071,437 | 2,119,920 | Gas |
| 12 | TOTAL Account 154 (Enter Total of lines 5 thru 11) | 7,135,178 | 7,563,043 | |
| 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) | 377,589 | 327,844 | Electric & Gas |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | TOTAL Materials and Supplies (Per Balance Sheet) | 7,551,592 | 7,925,501 | |

FOOTNOTE DATA

***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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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. | Allowances Inventory (Account 158.1) (a) | Current Year | | 2009 | |
|---|---|---|---|---|---|
| | | No. (b) | Amt. (c) | No. (d) | 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 | | | | | |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

| 2010 | | 2011 | | Future Years | | Totals | | Line |
|---|---|---|---|---|---|---|---|---|
| No. (f) | Amt. (g) | No. (h) | Amt. (i) | No. (j) | Amt. (k) | No. (l) | Amt. (m) | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| | | | | Account Charged (d) | Amount (e) | |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) |
|---|---|---|---|---|---|---|
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| 49 | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

## 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** | | | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 $50,000 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 | | Balance at end of Current Quarter/Year |
|---|---|---|---|---|---|---|
| | | | | Written off During the Quarter/Year Account Charged | Written off During the Period Amount | |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | FAS 158 Other Post Employment Benefits | 12,931,125 | 19,277,572 | 182, 234, | 8,345,448 | 23,863,249 |
| 2 | | | | 253 | | |
| 3 | FAS 158 Pensions | 6,372,915 | 99,237,297 | 182, 234, | 4,456,043 | 101,154,169 |
| 4 | | | | 253 | | |
| 5 | FAS 109 Temporary Differences | 502,130 | 9,283 | 410 | 174,454 | 336,959 |
| 6 | | | | | | |
| 7 | Illinois Gas Rate Case Expenses | 169,667 | | 928 | 169,667 | |
| 8 | Amortization period of 5 years starting | | | | | |
| 9 | October 2003 | | | | | |
| 10 | | | | | | |
| 11 | Electric Post 2006 Rate Case | 574,752 | | 407, 928 | 287,376 | 287,376 |
| 12 | Amortization period of 3 years starting | | | | | |
| 13 | January 2007 | | | | | |
| 14 | | | | | | |
| 15 | Asset Retirement Obligation - Regulated Asset | 894,640 | 63,798 | | | 958,438 |
| 16 | | | | | | |
| 17 | Illinois Electric and Gas Rate Cases | 316,678 | 1,526,493 | 182, 928 | 617,772 | 1,225,399 |
| 18 | Expenses - 2007 | | | | | |
| 19 | Amortization period of 3 years starting | | | | | |
| 20 | October 2008 | | | | | |
| 21 | | | | | | |
| 22 | FAS 133 Regulatory Asset - Current | | 429,858 | 245 | 429,858 | |
| 23 | | | | | | |
| 24 | Illinois Swap | | 92,506,603 | 245 | 63,253,068 | 29,253,535 |
| 25 | | | | | | |
| 26 | Auction Improvement/2008 Auction Design | | 81,674 | 407 | 6,797 | 74,877 |
| 27 | Costs | | | | | |
| 28 | | | | | | |
| 29 | | | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
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| 33 | | | | | | |
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| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | TOTAL | 21,761,907 | 213,132,578 | | 77,740,483 | 157,154,002 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 $50,000, 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 | Deferred OPEB Expense | 67,444 | | 926 | 67,444 | |
| 2 | | | | | | |
| 3 | Work in Progress | 17,874 | 122,899 | Various | 29,643 | 111,130 |
| 4 | | | | | | |
| 5 | Deferred Pension Expense | 3,722,271 | | 926 | 3,722,271 | |
| 6 | | | | | | |
| 7 | Coal Tar Rider | 5,303,130 | 7,607,991 | 925 | 4,294,180 | 8,616,941 |
| 8 | | | | | | |
| 9 | Margin for Natural Gas Futures | 1,162,333 | 15,000,962 | 131 | 10,012,312 | 6,150,983 |
| 10 | | | | | | |
| 11 | Electric Energy Efficiency & | | | | | |
| 12 | Demand Response Programs | 8,923 | 594,691 | 920 | 1,295,843 | -692,229 |
| 13 | | | | | | |
| 14 | Gas Energy Efficiency | | 57,537 | 928 | 11,186 | 46,351 |
| 15 | | | | | | |
| 16 | IBNR Workers Compensation | | | 925 | 37,536 | -37,536 |
| 17 | | | | | | |
| 18 | 2008/2009 Electric/Gas | | | | | |
| 19 | Rate Case | | 18,113 | 928 | | 18,113 |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
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| 44 | | | | | | |
| 45 | | | | | | |
| 46 | | | | | | |
| 47 | Misc. Work in Progress | | | | | |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 10,281,975 | | | | 14,213,753 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | SFAS No. 109 ADIT Unamortized Investment Tax Credit | 1,310,131 | 1,020,305 |
| 3 | Other Non-property temporary differences | 38,380,944 | 37,941,441 |
| 4 | | | |
| 5 | | | |
| 6 | | | |
| 7 | Other | | |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 39,691,075 | 38,961,746 |
| 9 | Gas | | |
| 10 | SFAS No. 109 ADIT Unamortized Investment Tax Credit | 1,335,312 | 1,173,744 |
| 11 | Other Non-property temporary differences | 12,521,491 | 12,718,687 |
| 12 | | | |
| 13 | | | |
| 14 | | | |
| 15 | Other | | |
| 16 | TOTAL Gas (Enter Total of lines 10 thru 15 | 13,856,803 | 13,892,431 |
| 17 | Other (Specify) | -406,636 | |
| 18 | TOTAL (Acct 190) (Total of lines 8, 16 and 17) | 53,141,242 | 52,854,177 |

Notes

FOOTNOTE DATA

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

| | | |
|---|---|---|
| Total Electric Account 190 | $ | 39,691,075 |
| SFAS No. 109 Unamortized Investment Tax Credit | | 1,310,131 |
| Electric Account 190 Excluding SFAS No. 109 ITC | $ | 38,380,944 |

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

| | |
|---|---|
| Production | 0.04% |
| Transmission | 3.53% |
| Distribution | 66.70% |
| General | 29.73% |

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

| | | |
|---|---|---|
| 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.: 17 Column: a***

Other includes deferrals related to Other Income and Deductions.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | 2,000,000 | | |
| 14 | Total Preferred | 7,000,000 | | |
| 15 | | | | |
| 16 | | | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 227,913,330 |
| 9 | | |
| 10 | Capital contribution related to Ameren Corp tax benefit for 2006 | 254,000 |
| 11 | | |
| 12 | Equity Infusion from CILCORP in 2007 | 15,000,000 |
| 13 | | |
| 14 | Subtotal (Account 211) | 243,167,330 |
| 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 | | |
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| 36 | | |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | TOTAL | 243,167,330 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | None | |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |
| 6 | | |
| 7 | | |
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| 18 | | |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 1,057,232 |
| 8 | | | 4,500 D |
| 9 | ACCOUNT 221 - Bonds - Pollution Control | | |
| 10 | Refunding G 6.20% 2012 | 1,000,000 | 78,823 |
| 11 | | | 5,820 D |
| 12 | Refunding H 5.90% 2023 | 32,000,000 | 400,765 |
| 13 | | | |
| 14 | Refunding I 7 day variable % 2039 | 14,200,000 | 409,965 |
| 15 | | | |
| 16 | Refunding I 7 day variable % 2026 | 5,000,000 | 139,231 |
| 17 | | | |
| 18 | | | |
| 19 | | | |
| 20 | | | |
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| 22 | | | |
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| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 298,200,000 | 3,681,804 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | 776,563 | 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 |
| 11/19/04 | 10/01/39 | 12/01/04 | 10/01/39 | | 315,360 | 14 |
| | | | | | | 15 |
| 11/19/04 | 10/01/26 | 12/01/04 | 10/01/26 | | 105,120 | 16 |
| | | | | | | 17 |
| | | | | | | 18 |
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| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 279,000,000 | 9,309,043 | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | 69,638,345 |
| 2 | | |
| 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 | 5,388,487 |
| 11 | Deferred Income Taxes | -2,120,452 |
| 12 | Plant Temporary Differences | 12,011,526 |
| 13 | | |
| 14 | Income Recorded on Books Not Included in Return | |
| 15 | Equity in Earnings of Subsidiaries | 52,594,611 |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | Deductions on Return Not Charged Against Book Income | |
| 20 | Plant Temporary Differences | 18,640,852 |
| 21 | Other* | 9,303,665 |
| 22 | | |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | Federal Tax Net Income | 4,378,778 |
| 28 | Show Computation of Tax: | |
| 29 | Federal Income Tax | 1,532,572 |
| 30 | Adjustments | 3,855,915 |
| 31 | | |
| 32 | Total Federal Income Tax | 5,388,487 |
| 33 | | |
| 34 | *See Attached Notes | |
| 35 | | |
| 36 | | |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | | |
| 44 | | |

***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 | (11,766,674 |
| Ameren Energy Development Company | (140,799) |
| Ameren Energy Resources, LLC | (550,003) |
| Ameren Energy Fuels and Services Company | (1,290,985) |
| CLC Aircraft Leasing Company | 303,068 |
| Ameren Corporation | (8,974,964) |
| Ameren Services | 4,561,732 |
| AmerenEnergy Resources Generation Company | 13,837,773 |
| CILCorp | (9,733,540) |
| CIM Energy Investment, Inc. | - |
| CIPSCO Investment Company | - |
| Central Illinois Light Company | 5,388,487 |
| Central Illinois Public Service Company | 4,367,370 |
| CIPSCO Leasing Company | 1,021,374 |
| Coffeen and Western Railroad | (51,781) |
| Electric Energy Inc. | 58,825,670 |
| Energy Risk Assurance Company | (1,731,874) |
| ESE Land Corporation | - |
| Ameren Energy Generating | 73,387,448 |
| Ameren Energy Marketing | (2,393,058) |
| Ameren Energy Resources | (434,283) |
| Illinois Material Supply Company | 83,243 |
| Illinois Power Company | (11,097,618) |
| Illinois Transmission Company | 470,301 |
| CLC Leasing Company A | - |
| Missouri Central Railroad | (106,924) |
| Midwest Electric Power, Inc. | 157,496 |
| Met-South, Inc. | 351,350 |
| Missouri Risk Assurance | 520,829 |
| Medina Valley CoGen, LLC | 1,947,435 |
| QST Enterprises, Inc. | 280,809 |
| Union Electric Development Company | - |
| Union Electric Company | 39,052,556 |
| Total | 156,284,438 |

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

Deductions Recorded on Books Not Deducted for Return – Other

| | | |
|---|---|---|
| Disallowance of Meals | $ | 7,063 |
| Lobbying Expenses | $ | 767,716 |
| Penalties Expenses | $ | 20,067 |
| Active VEBA | $ | 253,816 |
| Change in Legal Expense Reserve | $ | 93,723 |
| Change in Uncollectible Accounts | $ | 235,096 |
| Tax Reserve Interest – Current | $ | 610,140 |
| Tax Reserve Interest – Noncurrent | $ | 3,243 |
| Asset Retirement Obligation | $ | 1,143,582 |

FOOTNOTE DATA

| | | | |
|---|---|---|---|
| Environmental Remediation | $ | 16,920 | |
| FAS 133 Transactions | $ | 5,728,583 | |
| Gas Storage Fields | $ | 2,022,532 | |
| Manufactured Gas Clean-up | $ | 155,727 | |
| Purchased Gas Adj. | $ | 303,873 | |
| State Income Tax Adjustment | $ | 649,445 | |
| TOTAL Deductions Recorded on Books Not Deductible for Return – Other | $ | | 12,011,526 |

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

Deductions on Return Not Charged Against Book Income

| | | | |
|---|---|---|---|
| Company Owned Life Insurance | $ | 4,272,138 | |
| FAS 106-2 Medicare Prescription Drug | $ | 1,452,000 | |
| Federal Tax Exempt Interest | $ | 19,384 | |
| Preferred Dividend Paid Credit | $ | 200,275 | |
| Change in Injuries & Damages | $ | 1,187,692 | |
| Deferred Compensation | $ | 541,186 | |
| FAS 106 Book/Tax (OPEB) | $ | 591,989 | |
| IBNR | $ | 35,497 | |
| Pension Expense Allowed/Disallowed | $ | 412,305 | |
| Book/Tax Loss on Reacquired Debt | $ | 139,524 | |
| Rate Case Expenses | $ | 451,675 | |
| TOTAL Deductions on Return Not Charged Against Book Income – Other | $ | | 9,303,665 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 220,599 | | 5,388,487 | -1,393,415 | |
| 3 | State | | | | | |
| 4 | Illinois | -498,638 | | 2,162,306 | 821,000 | |
| 5 | Kansas | | | 3,995 | 3,995 | |
| 6 | Missouri | | | -104,383 | -104,383 | |
| 7 | Total Income Taxes | -278,039 | | 7,450,405 | -672,803 | |
| 8 | | | | | | |
| 9 | Other Taxes: | | | | | |
| 10 | Payroll Taxes: | | | | | |
| 11 | SS & Medicare-2007 | | | | | |
| 12 | SS & Medicare-2008 | | | 2,331,999 | 2,331,999 | |
| 13 | Federal Unemployment-2007 | | | 81 | 81 | |
| 14 | Federal Unemployment-2008 | | | 23,027 | 23,027 | |
| 15 | Illinois Unemployment - 2007 | | | 588 | 588 | |
| 16 | Illinois Unemployment - 2008 | | | 73,635 | 73,635 | |
| 17 | Subtotal Payroll Taxes | | | 2,429,330 | 2,429,330 | |
| 18 | | | | | | |
| 19 | Property Taxes: | | | | | |
| 20 | IL Electric Distrib-2005 | | | -667,391 | -667,391 | |
| 21 | IL Electric Distrib-2006 | | | -69,433 | -69,433 | |
| 22 | IL Electric Distrib-2007 | 221,312 | | -221,312 | | |
| 23 | IL Electric Distrib-2008 | | | 6,000,000 | 5,753,272 | |
| 24 | IL Invested Capital-2007 | -232,760 | | 232,760 | | |
| 25 | IL Invested Capital-2008 | | | 1,150,000 | 1,057,164 | |
| 26 | Illinois Real Estate-2007 | 622,770 | | 6,690 | 629,460 | |
| 27 | Illinois Real Estate-2008 | | | 655,000 | 2,230 | |
| 28 | Oklahoma Pers Prop-2008 | | | 11,989 | 11,989 | |
| 29 | Subtotal Property Taxes | 611,322 | | 7,098,303 | 6,717,291 | |
| 30 | Gross Recipts Taxes | | | | | |
| 31 | IL Assistance Charges-2007 | 372,469 | | -12,111 | 360,358 | |
| 32 | IL Assistance Charges-2008 | | | 4,388,459 | 4,019,684 | |
| 33 | ICC Gross Revenue - 2007 | | | 2,515 | 2,515 | |
| 34 | ICC Gross Revenue - 2008 | | | 339,175 | 339,175 | |
| 35 | IL Gross | 756,204 | | 132,473 | | |
| 36 | Illinois Gas Revenue - 2007 | -69,363 | | 64,766 | -4,597 | |
| 37 | Illinois Gas Revenue - 2008 | | | 7,108,762 | 6,675,945 | |
| 38 | IL Municipal Taxes-2007 | 68,467 | | -5,128 | 63,339 | |
| 39 | IL Municipal Taxes-2008 | | | 676,820 | 594,480 | |
| 40 | Subtotal Gross Receipts | 1,127,777 | | 12,695,731 | 12,050,899 | |
| 41 | TOTAL | 1,461,060 | | 30,076,293 | 20,927,241 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | | | | | |
| 2 | Franchise & Misc. Taxes: | | | | | |
| 3 | Federal Excise Tax - 2008 | | | 188 | 188 | |
| 4 | IL Corporate Franchise-2008 | | | 402,336 | 402,336 | |
| 5 | SubTotal Francise & Misc Tax | | | 402,524 | 402,524 | |
| 6 | | | | | | |
| 7 | Total Other Taxes: | 1,739,099 | | 22,625,888 | 21,600,044 | |
| 8 | | | | | | |
| 9 | Summary by Jurisdiction - | | | | | |
| 10 | See footnote | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
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| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 1,461,060 | | 30,076,293 | 20,927,241 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 |
| 7,002,501 | | 842,351 | | | 4,546,136 | 2 |
| | | | | | | 3 |
| 842,668 | | 748,610 | | | 1,413,696 | 4 |
| | | 3,995 | | | | 5 |
| | | -104,383 | | | | 6 |
| 7,845,169 | | 1,490,573 | | | 5,959,832 | 7 |
| | | | | | | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| | | 954,739 | | | 1,377,260 | 12 |
| | | -2,419 | | | 2,500 | 13 |
| | | 10,187 | | | 12,840 | 14 |
| | | -16,277 | | | 16,865 | 15 |
| | | -15,713 | | | 89,348 | 16 |
| | | 930,517 | | | 1,498,813 | 17 |
| | | | | | | 18 |
| | | | | | | 19 |
| | | -667,391 | | | | 20 |
| | | -69,433 | | | | 21 |
| | | -221,312 | | | | 22 |
| 246,728 | | 6,000,000 | | | | 23 |
| | | | | | 232,760 | 24 |
| 92,836 | | | | | 1,150,000 | 25 |
| | | 5,169 | | | 1,521 | 26 |
| 652,770 | | 539,470 | | | 115,530 | 27 |
| | | | | | 11,989 | 28 |
| 992,334 | | 5,586,503 | | | 1,511,800 | 29 |
| | | | | | | 30 |
| | | -3,427 | | | -8,684 | 31 |
| 368,775 | | 2,405,036 | | | 1,983,423 | 32 |
| | | | | | 2,515 | 33 |
| | | | | | 339,175 | 34 |
| 888,677 | | | | | 132,473 | 35 |
| | | | | | 64,766 | 36 |
| 432,817 | | | | | 7,108,762 | 37 |
| | | | | | -5,128 | 38 |
| 82,340 | | | | | 676,820 | 39 |
| 1,772,609 | | 2,401,609 | | | 10,294,122 | 40 |
| 10,610,112 | | 10,670,537 | | | 19,405,756 | 41 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 |
| | | | | | | 2 |
| | | 188 | | | | 3 |
| | | 261,147 | | | 141,189 | 4 |
| | | 261,335 | | | 141,189 | 5 |
| | | | | | | 6 |
| 2,764,943 | | 9,179,964 | | | 13,445,924 | 7 |
| | | | | | | 8 |
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| | | | | | | 39 |
| | | | | | | 40 |
| 10,610,112 | | 10,670,537 | | | 19,405,756 | 41 |

FOOTNOTE DATA

***Schedule Page: 262.1 Line No.: 9 Column: a***

| Kind of Tax | Taxes Accrued | Taxes Charged During Year | Taxes Paid During Year | Adjust | Taxes Accrued | Electric | Other |
|---|---|---|---|---|---|---|---|
| Federal Taxes | 220,599 | 7,743,782 | 961,880 | 0 | 7,002,502 | 1,805,046 | 5,938,736 |
| Illinois Taxes | 1,171,994 | 21,749,218 | 19,395,941 | 0 | 3,525,271 | 8,965,879 | 12,783,339 |
| Illinois Municipal Taxes | 68,467 | 671,692 | 657,819 | 0 | 82,340 | 0 | 671,692 |
| Kansas Taxes | 0 | 3,995 | 3,995 | 0 | 0 | 3,995 | 0 |
| Missouri Taxes | 0 | (104,383) | (104,383) | 0 | 0 | (104,383) | 0 |
| Oklahoma Taxes | 0 | 11,989 | 11,989 | 0 | 0 | 0 | 11,989 |
| | 1,461,060 | 30,076,293 | 20,927,241 | 0 | 10,610,112 | 10,670,537 | 19,405,756 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | | Allocations to Current Year's Income | | Adjustments (g) |
|---|---|---|---|---|---|---|---|
| | | | Account No. (c) | Amount (d) | Account No. (e) | Amount (f) | |
| 1 | Electric Utility | | | | | | |
| 2 | 3% | | | | | | |
| 3 | 4% | 7,919 | | | 411.5 | 7,250 | |
| 4 | 7% | | | | | | |
| 5 | 10% | 1,982,027 | | | 411.5 | 432,962 | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | TOTAL | 1,989,946 | | | | 440,212 | |
| 9 | Other (List separately and show 3%, 4%, 7%, 10% and TOTAL) | | | | | | |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | 3% | | | | | | |
| 13 | 4% | 10,286 | | | 411.5 | 8,207 | |
| 14 | 7% | 27,908 | | | 411.5 | 22,003 | |
| 15 | 10% | 1,990,001 | | | 411.5 | 215,194 | |
| 16 | | | | | | | |
| 17 | TOTAL | 2,028,195 | | | | 245,404 | |
| 18 | | | | | | | |
| 19 | | | | | | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 |
| 669 | 32 Years | | 3 |
| | | | 4 |
| 1,549,065 | 32 Years | | 5 |
| | | | 6 |
| | | | 7 |
| 1,549,734 | | | 8 |
| | | | 9 |
| | | | 10 |
| | | | 11 |
| | | | 12 |
| 2,079 | 35 Years | | 13 |
| 5,905 | 35 Years | | 14 |
| 1,774,807 | 35 Years | | 15 |
| | | | 16 |
| 1,782,791 | | | 17 |
| | | | 18 |
| | | | 19 |
| | | | 20 |
| | | | 21 |
| | | | 22 |
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FOOTNOTE DATA

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

Functionalization of Account 255 Total Electric Balance Beginning of Year

| | |
|---|---|
| Production | 0.00% |
| Transmission | 11.14% |
| Distribution | 83.40% |
| General | 5.46% |

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

Functionalization of Account 255 Total Electric End of Year

| | |
|---|---|
| Production | 0.00% |
| Transmission | 11.29% |
| Distribution | 82.90% |
| General | 5.81% |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 $10,000, 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 | 5,370,000 | 186 | 1,930,000 | 4,510,000 | 7,950,000 |
| 2 | | | | | | |
| 3 | FAS 87 Accrued Pension Liability | 26,835,910 | 926 | 14,948,765 | 7,200,494 | 19,087,639 |
| 4 | | | | | | |
| 5 | Deferred Compensation | 2,205,695 | 926 | 131,470 | 56,870 | 2,131,095 |
| 6 | | | | | | |
| 7 | Deferred Compensation- | 4,343,256 | 926 | 497,305 | 617,000 | 4,462,951 |
| 8 | Supplemental | | | | | |
| 9 | Deferred Earnings | 6,966,394 | various | 468,503 | 4,629 | 6,502,520 |
| 10 | | | | | | |
| 11 | Environmental Liability | 1,650,000 | 215 | 1,650,000 | | |
| 12 | | | | | | |
| 13 | FAS 158 Adjustment for Pension | 3,747,834 | 182 | 3,423,694 | 88,384,270 | 88,708,410 |
| 14 | | | | | | |
| 15 | Other Deferred Credit Deposit | | | | | |
| 16 | Requests | 1,803,728 | 142 | 4,704,902 | 4,807,797 | 1,906,623 |
| 17 | | | | | | |
| 18 | Post Retirement Benefits | 62,887,761 | 926 | 9,022,518 | 7,959,044 | 61,824,287 |
| 19 | | | | | | |
| 20 | Post Retirement Benefits-Part D | -1,020,804 | 926 | 1,573,917 | 525,958 | -2,068,763 |
| 21 | | | | | | |
| 22 | FAS 158 Adjustment for Other Post | | | | | |
| 23 | Retirement Benefits | 19,828,043 | 182 | 7,125,472 | 14,288,905 | 26,991,476 |
| 24 | | | | | | |
| 25 | FAS 158 Adjustment for Other Post | | | | | |
| 26 | Retirement Benefits, Medicare | | | | | |
| 27 | Part D | -9,734,000 | 182 | 1,047,527 | 1,548,527 | -9,233,000 |
| 28 | | | | | | |
| 29 | Tax Interest Accrual | 7,581 | 431 | | 3,243 | 10,824 |
| 30 | | | | | | |
| 31 | Auction Margins | 267,073 | 557 | 1,511,014 | 1,243,941 | |
| 32 | | | | | | |
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| 45 | | | | | | |
| 46 | | | | | | |
| 47 | TOTAL | 125,158,471 | | 48,035,087 | 131,150,678 | 208,274,062 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | 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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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. |
|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | |
| Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | (k) | |
| | | | | | | | 1 |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | Amounts Credited to Account 411.1 (d) |
| 1 | Account 282 | | | |
| 2 | Electric | 71,314,186 | 4,471,298 | 427,461 |
| 3 | Gas | 7,704,717 | 1,569,756 | 847,504 |
| 4 | Other Income and Deductions | -5,558,477 | | |
| 5 | TOTAL (Enter Total of lines 2 thru 4) | 73,460,426 | 6,041,054 | 1,274,965 |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Account 282 (Enter Total of lines 5 thru | 73,460,426 | 6,041,054 | 1,274,965 |
| 10 | Classification of TOTAL | | | |
| 11 | Federal Income Tax | 60,415,562 | 5,347,228 | 942,618 |
| 12 | State Income Tax | 13,044,864 | 693,826 | 332,347 |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 399,104 | 282 | 160,003 | 75,118,922 | 2 |
| | | 282 | 17,717 | 282 | 16,656 | 8,425,908 | 3 |
| 1,970,535 | 389,532 | 282 | 5,489,493 | 282 | 5,729,655 | -3,737,312 | 4 |
| 1,970,535 | 389,532 | | 5,906,314 | | 5,906,314 | 79,807,518 | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| 1,970,535 | 389,532 | | 5,906,314 | | 5,906,314 | 79,807,518 | 9 |
| | | | | | | | 10 |
| 1,898,622 | 337,977 | | 5,489,493 | | 5,489,493 | 66,380,817 | 11 |
| 71,913 | 51,555 | | 416,821 | | 416,821 | 13,426,701 | 12 |
| | | | | | | | 13 |

NOTES (Continued)

FOOTNOTE DATA

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

| | | |
|---|---|---|
| Electric Account 282 | $ | 71,314,186 |
| FASB No. 109 | | 308,638 |
| Account 282 Excluding FASB No. 109 | $ | 71,005,548 |

Functionalization of Account 282 Total Electric Balance Beginning of Year

| | |
|---|---|
| Production | 0.00% |
| Transmission | 11.14% |
| Distribution | 83.40% |
| General | 5.46% |

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

| | | |
|---|---|---|
| Electric Account 282 | $ | 75,118,922 |
| FASB No. 109 | | - |
| Account 282 Excluding FASB No. 109 | $ | 75,118,922 |

Functionalization of Account 282 Total Electric Balance End of Year

| | |
|---|---|
| Production | 0.00% |
| Transmission | 11.29% |
| Distribution | 82.90% |
| General | 5.81% |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | -2,845,937 | 453,245 | 4,183,534 |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Electric (Total of lines 3 thru 8) | -2,845,937 | 453,245 | 4,183,534 |
| 10 | Gas | | | |
| 11 | | -2,348,352 | 4,901,842 | 7,441,708 |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | TOTAL Gas (Total of lines 11 thru 16) | -2,348,352 | 4,901,842 | 7,441,708 |
| 18 | Other Income and Deductions | 650,997 | | |
| 19 | TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18) | -4,543,292 | 5,355,087 | 11,625,242 |
| 20 | Classification of TOTAL | | | |
| 21 | Federal Income Tax | -3,563,959 | 4,370,399 | 9,487,653 |
| 22 | State Income Tax | -979,333 | 984,688 | 2,137,589 |
| 23 | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | | | | Balance at End of Year | Line No. |
|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | |
| Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | (k) | |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | 283 | 2 | 283 | 2 | -6,576,226 | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | 2 | | 2 | -6,576,226 | 9 |
| | | | | | | | 10 |
| | | | | 190 | 1 | -4,888,217 | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| | | | | | | | 15 |
| | | | | | | | 16 |
| | | | | | 1 | -4,888,217 | 17 |
| 2,274,248 | 2,300,766 | 190283 | 138,299 | 190283 | 155,297 | 641,477 | 18 |
| 2,274,248 | 2,300,766 | | 138,301 | | 155,300 | -10,822,966 | 19 |
| | | | | | | | 20 |
| 1,856,061 | 1,877,703 | | 112,854 | | 129,851 | -8,685,858 | 21 |
| 418,187 | 423,063 | | 25,447 | | 25,449 | -2,137,108 | 22 |
| | | | | | | | 23 |

NOTES (Continued)

FOOTNOTE DATA

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

| | | |
|---|---|---|
| Electric Account 283 | $ | (2,845,937) |
| FASB No. 109 | | - |
| Account 283 Excluding FASB No. 109 | $ | (2,845,937) |

Functionalization of Account 283 Total Electric Balance Beginning of Year

| | |
|---|---|
| Production | 0.00% |
| Transmission | 11.43% |
| Distribution | 83.28% |
| General | 5.29% |

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

| | | |
|---|---|---|
| Electric Account 283 | $ | (6,576,226) |
| FASB No. 109 | | - |
| Account 283 Excluding FASB No. 109 | $ | (6,576,226) |

Functionalization of Account 283 Total Electric Balance End of Year

| | |
|---|---|
| Production | 0.00% |
| Transmission | 11.04% |
| Distribution | 82.75% |
| General | 6.21% |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 $50,000 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 | Balance at Begining of Current Quarter/Year | DEBITS | | Credits | Balance at End of Current Quarter/Year |
|---|---|---|---|---|---|---|
| | | | Account Credited | Amount | | |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | SFAS No. 109 - Unamortized Investment Tax Credits | 2,645,443 | 411 | 451,393 | | 2,194,050 |
| 2 | | | | | | |
| 3 | SFAS No. 109 - Excess Deferred Depreciation | 5,142,118 | 411 | 1,568,414 | 5,438 | 3,579,142 |
| 4 | | | | | | |
| 5 | FAS 133 Regulatory Liability | | 176 | 84,399 | 84,399 | |
| 6 | | | | | | |
| 7 | FAS 133 Asset/Liability Cumulative Gain or Loss | 80,455 | various | 70,329,922 | 45,503,504 | -24,745,963 |
| 8 | | | | | | |
| 9 | Regulatory Liability - Tax Effect of | | | | | |
| 10 | FAS 158 Pension and OPEB Adjustment | 6,408,620 | 190 | 732,113 | 402,267 | 6,078,774 |
| 11 | | | | | | |
| 12 | Illinois Swap | 19,351,563 | 176, 182 | 109,112,538 | 89,760,975 | |
| 13 | | | | | | |
| 14 | | | | | | |
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 33,628,199 | | 182,278,779 | 135,756,583 | -12,893,997 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

| 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 | 196,162,409 | 180,545,361 |
| 3 | (442) Commercial and Industrial Sales | | |
| 4 | Small (or Comm.) (See Instr. 4) | 106,636,898 | 116,651,792 |
| 5 | Large (or Ind.) (See Instr. 4) | 77,953,164 | 33,183,822 |
| 6 | (444) Public Street and Highway Lighting | 2,388,645 | 2,453,060 |
| 7 | (445) Other Sales to Public Authorities | -24,883 | 26,122 |
| 8 | (446) Sales to Railroads and Railways | | |
| 9 | (448) Interdepartmental Sales | | |
| 10 | TOTAL Sales to Ultimate Consumers | 383,116,233 | 332,860,157 |
| 11 | (447) Sales for Resale | 28,645 | -48,948 |
| 12 | TOTAL Sales of Electricity | 383,144,878 | 332,811,209 |
| 13 | (Less) (449.1) Provision for Rate Refunds | 7,287,451 | 3,391,926 |
| 14 | TOTAL Revenues Net of Prov. for Refunds | 375,857,427 | 329,419,283 |
| 15 | Other Operating Revenues | | |
| 16 | (450) Forfeited Discounts | 2,410,659 | 1,279,674 |
| 17 | (451) Miscellaneous Service Revenues | 19,548 | 24,994 |
| 18 | (453) Sales of Water and Water Power | | |
| 19 | (454) Rent from Electric Property | 1,860,522 | 2,152,476 |
| 20 | (455) Interdepartmental Rents | | |
| 21 | (456) Other Electric Revenues | 30,398,926 | 47,764,770 |
| 22 | (456.1) Revenues from Transmission of Electricity of Others | 6,486,849 | 6,560,437 |
| 23 | (457.1) Regional Control Service Revenues | | |
| 24 | (457.2) Miscellaneous Revenues | | |
| 25 | | | |
| 26 | TOTAL Other Operating Revenues | 41,176,504 | 57,782,351 |
| 27 | TOTAL Electric Operating Revenues | 417,033,931 | 387,201,634 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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 |
| 2,065,882 | 2,043,903 | 188,770 | 185,147 | 2 |
| | | | | 3 |
| 1,988,261 | 1,938,173 | 24,865 | 24,335 | 4 |
| 2,436,254 | 2,382,747 | 155 | 147 | 5 |
| 24,408 | 25,783 | 544 | 541 | 6 |
| -604 | 1,015 | 9 | 8 | 7 |
| | | | | 8 |
| | | | | 9 |
| 6,514,201 | 6,391,621 | 214,343 | 210,178 | 10 |
| | 2,918 | | | 11 |
| 6,514,201 | 6,394,539 | 214,343 | 210,178 | 12 |
| | | | | 13 |
| 6,514,201 | 6,394,539 | 214,343 | 210,178 | 14 |

Line 12, column (b) includes $ 6,090,000 of unbilled revenues.

Line 12, column (d) includes 22,391 MWH relating to unbilled revenues

FOOTNOTE DATA

***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 |
|---|---|---|
| (442) Small or Commercial | 1,081,927 | 827,771 |
| (442) Large or Industrial | 1,982,998 | 2,041,070 |
| | 2,474,925 | 2,868,841 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) |
|---|---|---|---|---|---|
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | -30 | -2,175 | | | 0.0725 |
| 2 | Outdoor Protective Lighting | | -34 | | | |
| 3 | Total (440) Residential Sales | -30 | -2,209 | | | 0.0736 |
| 4 | | | | | | |
| 5 | Commercial General Service | -3 | -1,926 | | | 0.6420 |
| 6 | Outdoor Protective Lighting | -3 | -1,449 | | | 0.4830 |
| 7 | Limited Off-Peak Service | -14 | -436 | | | 0.0311 |
| 8 | Total Commercial | -20 | -3,811 | | | 0.1906 |
| 9 | | | | | | |
| 10 | Industrial | 263,664 | 23,599,970 | 1 | 263,664,000 | 0.0895 |
| 11 | Unbilled | 20,778 | 980,000 | | | 0.0472 |
| 12 | Total Industrial | 284,442 | 24,579,970 | 1 | 284,442,000 | 0.0864 |
| 13 | | | | | | |
| 14 | Residential BGS-1 | 2,020,415 | 116,373,970 | 188,530 | 10,717 | 0.0576 |
| 15 | Residential BGS-1-Unbilled | 42,865 | 2,586,000 | | | 0.0603 |
| 16 | Total Residential BGS-1 | 2,063,280 | 118,959,970 | 188,530 | 10,944 | 0.0577 |
| 17 | | | | | | |
| 18 | Residential DS-1 | | 76,119,377 | | | |
| 19 | Residential DS-1-Unbilled | | 946,000 | | | |
| 20 | Total Residential DS-1 | | 77,065,377 | | | |
| 21 | | | | | | |
| 22 | Residential RTP-1 | 2,632 | 139,271 | 240 | 10,967 | 0.0529 |
| 23 | Total Residential RTP-1 | 2,632 | 139,271 | 240 | 10,967 | 0.0529 |
| 24 | | | | | | |
| 25 | Commercial BGS-2 | 656,136 | 51,446,872 | 21,926 | 29,925 | 0.0784 |
| 26 | Commercial BGS-2-Unbilled | 13,210 | 1,027,000 | | | 0.0777 |
| 27 | | | | | | |
| 28 | Commercial BGS-3 | 237,143 | 16,691,049 | 316 | 750,453 | 0.0704 |
| 29 | Commercial BGS-3-Unbilled | -4,067 | -309,000 | | | 0.0760 |
| 30 | | | | | | |
| 31 | Commercial BGS-4 | 5,303 | 485,756 | 1 | 5,303,000 | 0.0916 |
| 32 | Commercial BGS-4-Unbilled | -17,233 | -1,543,000 | | | 0.0895 |
| 33 | Total Commercial BGS | 890,492 | 67,798,677 | 22,243 | 40,035 | 0.0761 |
| 34 | | | | | | |
| 35 | Commercial DS-2 | | 22,917,620 | | | |
| 36 | Commercial DS-2-Unbilled | | -32,000 | | | |
| 37 | | | | | | |
| 38 | Commercial DS-3 | | 12,600,831 | | | |
| 39 | Commercial DS-3-Unbilled | | -513,000 | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed | 6,491,810 | 377,026,233 | 214,343 | 30,287 | 0.0581 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 22,391 | 6,090,000 | 0 | 0 | 0.2720 |
| 43 | TOTAL | 6,514,201 | 383,116,233 | 214,343 | 30,391 | 0.0588 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | 2,567,327 | | | |
| 2 | Commercial DS-4-Unbilled | | 596,000 | | | |
| 3 | Total Commercial DS | | 38,136,778 | | | |
| 4 | | | | | | |
| 5 | Commercial RTP-2 | 2,911 | 146,674 | 97 | 30,010 | 0.0504 |
| 6 | | | | | | |
| 7 | Commercial RTP-3 | 7,065 | 427,536 | 4 | 1,766,250 | 0.0605 |
| 8 | | | | | | |
| 9 | Commercial RTP-L | 7,770 | 498,044 | 4 | 1,942,500 | 0.0641 |
| 10 | Commercial BGS RTP-L-Unbilled | -1,884 | -367,000 | | | 0.1948 |
| 11 | Total Commercial RTP-L | 15,862 | 705,254 | 105 | 151,067 | 0.0445 |
| 12 | | | | | | |
| 13 | Industrial BGS-2 | 3,978 | 310,670 | 52 | 76,500 | 0.0781 |
| 14 | Industrial BGS-2-Unbilled | -333 | -24,000 | | | 0.0721 |
| 15 | | | | | | |
| 16 | Industrial BGS-3 | 28,179 | 1,979,021 | 19 | 1,483,105 | 0.0702 |
| 17 | Industrial BGS-3-Unbilled | -11 | -4,000 | | | 0.3636 |
| 18 | | | | | | |
| 19 | Industrial BGS-4 | | | | | |
| 20 | Industrial BGS-4-Unbilled | -3,007 | -272,000 | | | 0.0905 |
| 21 | Total Industrial BGS | 28,806 | 1,989,691 | 71 | 405,718 | 0.0691 |
| 22 | | | | | | |
| 23 | Industrial DS-2 | | 141,943 | | | |
| 24 | Industrial DS-2-Unbilled | | -1,000 | | | |
| 25 | | | | | | |
| 26 | Industrial DS-3 | | 1,160,316 | | | |
| 27 | Industrial DS-3-Unbilled | | -2,000 | | | |
| 28 | | | | | | |
| 29 | Industrial DS-4 | | 5,107,819 | | | |
| 30 | Industrial DS-4-Unbilled | | -125,000 | | | |
| 31 | Total Industrial DS | | 6,282,078 | | | |
| 32 | | | | | | |
| 33 | Industrial RTP-L | 722,117 | 41,918,425 | 11 | 65,647,000 | 0.0580 |
| 34 | Industrial RTP-L-Unbilled | 7,891 | 3,183,000 | | | 0.4034 |
| 35 | Total Industrial RTP-L | 730,008 | 45,101,425 | 11 | 66,364,364 | 0.0618 |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | Street Lighting BGS | 24,484 | 934,453 | 544 | 45,007 | 0.0382 |
| 39 | Street Lighting BGS-Unbilled | -76 | -2,000 | | | 0.0263 |
| 40 | Total Street Lighting BGS | 24,408 | 932,453 | 544 | 44,868 | 0.0382 |
| | | | | | | |
| 41 | TOTAL Billed | 6,491,810 | 377,026,233 | 214,343 | 30,287 | 0.0581 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 22,391 | 6,090,000 | 0 | 0 | 0.2720 |
| 43 | TOTAL | 6,514,201 | 383,116,233 | 214,343 | 30,391 | 0.0588 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | 1,464,192 | | | |
| 3 | Street Lighting DS-Unbilled | | -8,000 | | | |
| 4 | Total Street Lighting DS | | 1,456,192 | | | |
| 5 | | | | | | |
| 6 | Public Authority BGS | 205 | 1,292 | 9 | 22,778 | 0.0063 |
| 7 | Public Authority BGS-Unbilled | -809 | -21,000 | | | 0.0260 |
| 8 | Total Public Authority BGS | -604 | -19,708 | 9 | -67,111 | 0.0326 |
| 9 | | | | | | |
| 10 | Public Authority DS | | -175 | | | |
| 11 | Public Authority DS-Unbilled | | -5,000 | | | |
| 12 | Total Public Authority DS | | -5,175 | | | |
| 13 | | | | | | |
| 14 | ARES Commercial | 1,065,275 | | 2,517 | 423,232 | |
| 15 | ARES Commercial-Unbilled | 16,652 | | | | |
| 16 | Total ARES commercial | 1,081,927 | | 2,517 | 429,848 | |
| 17 | | | | | | |
| 18 | ARES Industrial | 1,444,583 | | 72 | 20,063,653 | |
| 19 | ARES Industrial-Unbilled | -51,585 | | | | |
| 20 | Total ARES Industrial | 1,392,998 | | 72 | 19,347,194 | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
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| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed | 6,491,810 | 377,026,233 | 214,343 | 30,287 | 0.0581 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 22,391 | 6,090,000 | 0 | 0 | 0.2720 |
| 43 | TOTAL | 6,514,201 | 383,116,233 | 214,343 | 30,391 | 0.0588 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | Statistical Classifi-cation | FERC Rate Schedule or Tariff Number | Average Monthly Billing Demand (MW) | Actual Demand (MW) | |
|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Midwest Independent System Operator | OS | CST1 | N/A | N/A | N/A |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
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| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

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. |
|---|---|---|---|---|---|
| | | 29,158 | -513 | 28,645 | 1 |
| | | | | | 2 |
| | | | | | 3 |
| | | | | | 4 |
| | | | | | 5 |
| | | | | | 6 |
| | | | | | 7 |
| | | | | | 8 |
| | | | | | 9 |
| | | | | | 10 |
| | | | | | 11 |
| | | | | | 12 |
| | | | | | 13 |
| | | | | | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 0 | 0 | 29,158 | -513 | 28,645 | |
| **0** | **0** | **29,158** | **-513** | **28,645** | |

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 | $ 364 |
| Market Settlement | (877) |
| Total | $(513) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 2,413 |
| 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 | 2,413 |
| 21 | TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20) | -2,213 | 2,413 |
| 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) | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) |
|---|---|---|---|
| 60 | D. Other Power Generation | | |
| 61 | Operation | | |
| 62 | (546) Operation Supervision and Engineering | | 10,127 |
| 63 | (547) Fuel | 27,516 | 914 |
| 64 | (548) Generation Expenses | | |
| 65 | (549) Miscellaneous Other Power Generation Expenses | | -1,000 |
| 66 | (550) Rents | | |
| 67 | TOTAL Operation (Enter Total of lines 62 thru 66) | 27,516 | 10,041 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | | |
| 70 | (552) Maintenance of Structures | 64,811 | 93,911 |
| 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) | 64,811 | 93,911 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73) | 92,327 | 103,952 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 273,053,574 | 254,955,684 |
| 77 | (556) System Control and Load Dispatching | | |
| 78 | (557) Other Expenses | 3,610,108 | 1,501,759 |
| 79 | TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78) | 276,663,682 | 256,457,443 |
| 80 | TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79) | 276,753,796 | 256,563,808 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 156,671 | 168,259 |
| 84 | (561) Load Dispatching | 63,692 | 100,860 |
| 85 | (561.1) Load Dispatch-Reliability | | |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 208,734 | 172,685 |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | | |
| 88 | (561.4) Scheduling, System Control and Dispatch Services | 639,396 | 261,013 |
| 89 | (561.5) Reliability, Planning and Standards Development | 43,065 | 50,175 |
| 90 | (561.6) Transmission Service Studies | 8 | 1,397 |
| 91 | (561.7) Generation Interconnection Studies | 73 | 11,845 |
| 92 | (561.8) Reliability, Planning and Standards Development Services | 42,974 | 16,755 |
| 93 | (562) Station Expenses | | 22,405 |
| 94 | (563) Overhead Lines Expenses | | 8,825 |
| 95 | (564) Underground Lines Expenses | | |
| 96 | (565) Transmission of Electricity by Others | 757,464 | 6,619,907 |
| 97 | (566) Miscellaneous Transmission Expenses | -123,224 | 462,469 |
| 98 | (567) Rents | | |
| 99 | TOTAL Operation (Enter Total of lines 83 thru 98) | 1,788,853 | 7,896,595 |
| 100 | Maintenance | | |
| 101 | (568) Maintenance Supervision and Engineering | 23,844 | 32,358 |
| 102 | (569) Maintenance of Structures | 59,355 | 77,953 |
| 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 | 206,268 | 360,913 |
| 108 | (571) Maintenance of Overhead Lines | 890,473 | 861,256 |
| 109 | (572) Maintenance of Underground Lines | | |
| 110 | (573) Maintenance of Miscellaneous Transmission Plant | 51,336 | 25,406 |
| 111 | TOTAL Maintenance (Total of lines 101 thru 110) | 1,231,276 | 1,357,886 |
| 112 | TOTAL Transmission Expenses (Total of lines 99 and 111) | 3,020,129 | 9,254,481 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 143,511 | 25,361 |
| 122 | (575.8) Rents | | |
| 123 | Total Operation (Lines 115 thru 122) | 143,511 | 25,361 |
| 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) | 143,511 | 25,361 |
| 132 | 4. DISTRIBUTION EXPENSES | | |
| 133 | Operation | | |
| 134 | (580) Operation Supervision and Engineering | 1,262,842 | 1,428,435 |
| 135 | (581) Load Dispatching | 1,349,246 | 996,806 |
| 136 | (582) Station Expenses | 228,413 | 424,751 |
| 137 | (583) Overhead Line Expenses | 1,178,910 | 959,643 |
| 138 | (584) Underground Line Expenses | 463,497 | 361,166 |
| 139 | (585) Street Lighting and Signal System Expenses | 303,492 | 237,952 |
| 140 | (586) Meter Expenses | 1,772,148 | 1,499,890 |
| 141 | (587) Customer Installations Expenses | 298,184 | 519,903 |
| 142 | (588) Miscellaneous Expenses | 5,375,303 | 5,366,971 |
| 143 | (589) Rents | 287,926 | 265,026 |
| 144 | TOTAL Operation (Enter Total of lines 134 thru 143) | 12,519,961 | 12,060,543 |
| 145 | Maintenance | | |
| 146 | (590) Maintenance Supervision and Engineering | 364,236 | 631,439 |
| 147 | (591) Maintenance of Structures | 473,031 | 319,112 |
| 148 | (592) Maintenance of Station Equipment | 2,337,974 | 1,887,807 |
| 149 | (593) Maintenance of Overhead Lines | 14,175,987 | 7,469,631 |
| 150 | (594) Maintenance of Underground Lines | 971,873 | 937,029 |
| 151 | (595) Maintenance of Line Transformers | 70,718 | 35,798 |
| 152 | (596) Maintenance of Street Lighting and Signal Systems | 333,642 | 272,912 |
| 153 | (597) Maintenance of Meters | 4,228 | 3,880 |
| 154 | (598) Maintenance of Miscellaneous Distribution Plant | 772,484 | 590,884 |
| 155 | TOTAL Maintenance (Total of lines 146 thru 154) | 19,504,173 | 12,148,492 |
| 156 | TOTAL Distribution Expenses (Total of lines 144 and 155) | 32,024,134 | 24,209,035 |
| 157 | 5. CUSTOMER ACCOUNTS EXPENSES | | |
| 158 | Operation | | |
| 159 | (901) Supervision | 8,009 | 2,001 |
| 160 | (902) Meter Reading Expenses | 1,922,600 | 1,890,408 |
| 161 | (903) Customer Records and Collection Expenses | 5,468,977 | 5,596,991 |
| 162 | (904) Uncollectible Accounts | 3,330,000 | 4,378,000 |
| 163 | (905) Miscellaneous Customer Accounts Expenses | 228,479 | 223,985 |
| 164 | TOTAL Customer Accounts Expenses (Total of lines 159 thru 163) | 10,958,065 | 12,091,385 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 78,553 | 33,737 |
| 168 | (908) Customer Assistance Expenses | 250,764 | 102,709 |
| 169 | (909) Informational and Instructional Expenses | 588,955 | 303,021 |
| 170 | (910) Miscellaneous Customer Service and Informational Expenses | 160,012 | 434,334 |
| 171 | TOTAL Customer Service and Information Expenses (Total 167 thru 170) | 1,078,284 | 873,801 |
| 172 | 7. SALES EXPENSES | | |
| 173 | Operation | | |
| 174 | (911) Supervision | | |
| 175 | (912) Demonstrating and Selling Expenses | 127,059 | 188,406 |
| 176 | (913) Advertising Expenses | | |
| 177 | (916) Miscellaneous Sales Expenses | 6,415 | 8,463 |
| 178 | TOTAL Sales Expenses (Enter Total of lines 174 thru 177) | 133,474 | 196,869 |
| 179 | 8. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 180 | Operation | | |
| 181 | (920) Administrative and General Salaries | 9,741,330 | 7,571,716 |
| 182 | (921) Office Supplies and Expenses | 3,011,952 | 2,818,838 |
| 183 | (Less) (922) Administrative Expenses Transferred-Credit | 329,807 | 287,781 |
| 184 | (923) Outside Services Employed | 4,612,902 | 5,382,076 |
| 185 | (924) Property Insurance | 566,007 | 545,882 |
| 186 | (925) Injuries and Damages | 780,617 | 2,737,756 |
| 187 | (926) Employee Pensions and Benefits | 3,980,881 | 8,354,060 |
| 188 | (927) Franchise Requirements | 1,443,177 | 1,504,396 |
| 189 | (928) Regulatory Commission Expenses | 1,374,550 | 1,271,724 |
| 190 | (929) (Less) Duplicate Charges-Cr. | 1,391,421 | 1,385,983 |
| 191 | (930.1) General Advertising Expenses | 302,502 | 404,625 |
| 192 | (930.2) Miscellaneous General Expenses | 653,327 | 358,083 |
| 193 | (931) Rents | 2,481,683 | 2,474,871 |
| 194 | TOTAL Operation (Enter Total of lines 181 thru 193) | 27,227,700 | 31,750,263 |
| 195 | Maintenance | | |
| 196 | (935) Maintenance of General Plant | 382,547 | 286,977 |
| 197 | TOTAL Administrative & General Expenses (Total of lines 194 and 196) | 27,610,247 | 32,037,240 |
| 198 | TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197) | 351,721,640 | 335,251,980 |

FOOTNOTE DATA

***Schedule Page: 320 Line No.: 84 Column: b***

Account 561 includes 561.BA cost of $63,692.

***Schedule Page: 320 Line No.: 84 Column: c***

Account 561 includes 561.BA cost of $83,449.

***Schedule Page: 320 Line No.: 96 Column: c***

The amount reported for account 565 reconciles to quarterly amounts reported on page 332 as follows:

| | |
|---|---|
| 1st quarter page 332 as reported | $ 3,128,923 |
| 2nd quarter page 332 as reported | 1,669,130 |
| 3rd quarter page 332 as reported | 2,219,439 |
| 4th quarter page 332 as reported | 795,325 |
| 1st quarter adjustment discovered in third quarter (see below) | (1,192,910) |
| TOTAL account 565 | $6,619,907 |

During the third quarter of 2007, we identified a misallocation of first quarter 2007 expense among Ameren subsidiaries. The error resulted in an overstatement of Central Illinois Light Co. expense of $1,192,910 during the three months ended March 31, 2007. In the third quarter of 2007 the correcting entry was booked. The third quarter Form 1 page 332 was prepared excluding this entry in order to present amounts that were actually applicable to the third quarter; therefore, the amount of the entry is a reconciling item on this footnote.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

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 | American Electric Power Service | OS | | | | |
| 2 | Central Illinois Public Service Co. | OS | | | | |
| 3 | CMS Energy Management | OS | | | | |
| 4 | Constellation Energy Commodities | OS | | | | |
| 5 | Dynegy Power Marketing | OS | | | | |
| 6 | DTE Energy | OS | | | | |
| 7 | Exelon Generation | OS | | | | |
| 8 | Ameren Energy Marketing | OS | | | | |
| 9 | Great River Energy | OS | | | | |
| 10 | Illinois Power Company | OS | | | | |
| 11 | J. Aron and Company | OS | | | | |
| 12 | JP Morgan Ventures Energy Corp | OS | | | | |
| 13 | City Water Light and Power | OS | | | | |
| 14 | Commonwealth Edison | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

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) | Average Monthly CP Demand (f) |
| 1 | Midwest Independent System Operator | OS | | | | |
| 2 | Minnesota Municipal Power Agency | OS | | | | |
| 3 | Morgan Stanley Capital Group | OS | | | | |
| 4 | Medina Valley | OS | | | | |
| 5 | City of Peru, Illinois | OS | | | | |
| 6 | Reliant Energy Services | OS | | | | |
| 7 | Resource Technology Services | OS | | | | |
| 8 | Sterling Plant | OS | | | | |
| 9 | Union Electric Company | OS | | | | |
| 10 | Wisconsin Public Service | OS | | | | |
| 11 | Dave Driscoll | OS | | | | |
| 12 | John Albers | OS | | | | |
| 13 | John Endress | OS | | | | |
| 14 | Metamora High School | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

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) | Average Monthly CP Demand (f) |
| 1 | Ralph E. Dorr | OS | | | | |
| 2 | Resource Technology Services | OS | | | | |
| 3 | Tazewell Company Landfill Gas Plant | OS | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| | Total | | | | | |

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) | |
| 1,798 | | | | 154,790 | | 154,790 | 1 |
| | | | -144,176 | -431,111 | | -575,287 | 2 |
| | | | 231,142 | | | 231,142 | 3 |
| 790,216 | | | | 52,732,986 | | 52,732,986 | 4 |
| 369,507 | | | 1,924,918 | 24,120,944 | 1,509,743 | 27,555,605 | 5 |
| 83,510 | | | 1,048 | 5,500,334 | | 5,501,382 | 6 |
| 8,992 | | | | 773,951 | | 773,951 | 7 |
| 908,631 | | | 1,007,713 | 63,767,659 | 3,133,030 | 67,908,402 | 8 |
| | | | 1,116 | 15,190 | | 16,306 | 9 |
| | | | -114,728 | -249,462 | | -364,190 | 10 |
| 53,783 | | | | 3,530,061 | | 3,530,061 | 11 |
| 194,856 | | | | 12,559,136 | | 12,559,136 | 12 |
| | | | | 244,319 | | 244,319 | 13 |
| | | | | 23,575 | | 23,575 | 14 |
| 4,141,614 | | | 8,965,174 | 257,375,575 | 7,002,384 | 273,343,133 | |

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 ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 1,476,439 | | | | 74,851,150 | 135,777 | 74,986,927 | 1 |
| | | | 40,152 | | | 40,152 | 2 |
| 2,698 | | | | 232,185 | | 232,185 | 3 |
| 226,362 | | | 4,387,200 | 18,088,658 | | 22,475,858 | 4 |
| | | | | 66,099 | | 66,099 | 5 |
| | | | 1,240,424 | | | 1,240,424 | 6 |
| 5,138 | | | | 240,221 | | 240,221 | 7 |
| | | | | 109,804 | | 109,804 | 8 |
| | | | 132,835 | | 2,067,212 | 2,200,047 | 9 |
| | | | 257,530 | | 156,622 | 414,152 | 10 |
| | | | | 34 | | 34 | 11 |
| | | | | 12 | | 12 | 12 |
| | | | | 447 | | 447 | 13 |
| | | | | 51 | | 51 | 14 |
| 4,141,614 | | | 8,965,174 | 257,375,575 | 7,002,384 | 273,343,133 | |

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) | |
| 1 | | | | 3 | | 3 | 1 |
| 1,622 | | | | 94,862 | | 94,862 | 2 |
| 18,061 | | | | 949,677 | | 949,677 | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| 4,141,614 | | | 8,965,174 | 257,375,575 | 7,002,384 | 273,343,133 | |

***Schedule Page: 326 Line No.: 2 Column: a***

Affiliate

***Schedule Page: 326 Line No.: 5 Column: l***

Amount represents Illinois Auction Ancillary Charges.

***Schedule Page: 326 Line No.: 8 Column: a***

Affiliate

***Schedule Page: 326 Line No.: 8 Column: l***

Amount represents Illinois Auction Ancillary Charges.

***Schedule Page: 326 Line No.: 10 Column: a***

Affiliate

***Schedule Page: 326.1 Line No.: 1 Column: l***

Detail of the Other Charges are as follows:

| | |
|---|---|
| MISO Activities | 462,474 |
| Inadvertent Energy | 5,342 |
| Energy Losses | (459,971) |
| Revenue Neutrality Uplift | 293,997 |
| Revenue Sufficiency Guarantees | 197,798 |
| Auction Revenue Rights | (363,863) |
| Total | 135,777 |

***Schedule Page: 326.1 Line No.: 9 Column: a***

Affiliate

***Schedule Page: 326.1 Line No.: 9 Column: l***

Amount represents Illinois Auction Ancillary Charges.

***Schedule Page: 326.1 Line No.: 10 Column: l***

Amount represents Illinois Auction Ancillary Charges.

***Schedule Page: 326.2 Line No.: 3 Column: m***

This note applies to the total of column M.

Total Purchased Power (Account 555) per this page (327, total colum M) will not agree to Purchased Power on page 321 (line 76B) as the purchased power number per this page does not include the MISO RSG Resettlement Accrual recorded as of 12/31/2008.

| | |
|---|---|
| Purchased Power page 327, Total Column M | 273,343,133 |
| MISO RSG Resettlement Accrual | 289,559 |
| Purchased Power page 321, line 76B | 273,053,574 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | Midwest Independent System Operator | Various | Various | LFP |
| 2 | Network Transmission System | Various | Various | OS |
| 3 | Auction Supplier System | Various | Various | OS |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | Line No. |
|---|---|---|---|---|---|---|
| | | | | MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | |
| | CILCO | MISO | | 5,248,198 | 5,248,198 | 1 |
| | CILCO | Various | | 2,363,213 | 2,363,213 | 2 |
| | CILCO | Various | | | | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
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| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | **0** | **7,611,411** | **7,611,411** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 (I), 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. |
|---|---|---|---|---|
| | 1,446,696 | 500,725 | 1,947,421 | 1 |
| | 5,040,153 | 3,033,509 | 8,073,662 | 2 |
| | | 3,366,684 | 3,366,684 | 3 |
| | | | | 4 |
| | | | | 5 |
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| | | | | 34 |
| **0** | **6,486,849** | **6,900,918** | **13,387,767** | |

FOOTNOTE DATA

***Schedule Page: 328 Line No.: 1 Column: a***

Central Illinois Lighting 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 services sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

***Schedule Page: 328 Line No.: 1 Column: d***

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:

| | |
|---|---|
| $ 441,744 | Scheduling System Control & Dispatch Service |
| 58,981 | Seams Elimination Charge |
| $ 500,725 | |

***Schedule Page: 328 Line No.: 2 Column: m***

The other charges listed in this column include:

| | |
|---|---|
| $ 1,962,236 | Regulation and Frequency Response Service |
| 159,410 | Facility Use |
| 821,355 | Spinning Reserve |
| 90,508 | Supplemental Reserve |
| $ 3,033,509 | |

***Schedule Page: 328 Line No.: 3 Column: m***

The Other Charges listed in this column include Ancillary Services.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | | | | |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Magawatt-hours Received (c) | Magawatt-hours Delivered (d) | Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
| 1 | Midwest Indep Oper Sys | FNS | 4,083,090 | 4,083,090 | | 757,464 | | 757,464 |
| 2 | | | | | | | | |
| 3 | | | | | | | | |
| 4 | | | | | | | | |
| 5 | | | | | | | | |
| 6 | | | | | | | | |
| 7 | | | | | | | | |
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| 12 | | | | | | | | |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| | TOTAL | | 4,083,090 | 4,083,090 | | 757,464 | | 757,464 |

FOOTNOTE DATA

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 1 | Industry Association Dues | 295,409 |
| 2 | Nuclear Power Research Expenses | |
| 3 | Other Experimental and General Research Expenses | 16,853 |
| 4 | Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities | 473,546 |
| 5 | Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000 | |
| 6 | Public Relations Expenses: | |
| 7 | Items less than $5,000 | 126,799 |
| 8 | D & B Sales | 5,614 |
| 9 | Image Element | 6,740 |
| 10 | | |
| 11 | Other Miscellaneous General Expenses: | |
| 12 | Standard & Poors | 70,500 |
| 13 | Items less than $5,000 | 26,928 |
| 14 | | |
| 15 | Trade Assoc, Public Service Org, & Chamber of | |
| 16 | Commerce Dues | |
| 17 | Items less than $5,000 | 90 |
| 18 | | |
| 19 | Apportioned to Gas Departments | -426,993 |
| 20 | | |
| 21 | Labor allocations from Service Company | 57,841 |
| 22 | | |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | | |
| 28 | | |
| 29 | | |
| 30 | | |
| 31 | | |
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| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | | |
| 44 | | |
| 45 | | |
| 46 | TOTAL | 653,327 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | | 9,083 | | 9,083 |
| 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 | 2,277,886 | | | | 2,277,886 |
| 8 | Distribution Plant | 27,027,449 | | | | 27,027,449 |
| 9 | Regional Transmission and Market Operation | | | | | |
| 10 | General Plant | 1,230,302 | | | | 1,230,302 |
| 11 | Common Plant-Electric | | | | | |
| 12 | TOTAL | 30,535,637 | | 9,083 | | 30,544,720 |

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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 350 | 1,756 | 75.00 | | 1.54 | R4 | 46.70 |
| 13 | 352 | 5,376 | 50.00 | -0.09 | 1.84 | R4 | 36.30 |
| 14 | 353 | 44,508 | 40.00 | -308.00 | 1.60 | R1 | 26.30 |
| 15 | 354 | 16,652 | 60.00 | -0.19 | 1.16 | S2 | 29.50 |
| 16 | 355 | 12,497 | 45.00 | -0.28 | 1.69 | S2 | 29.40 |
| 17 | 356 | 20,852 | 50.00 | -0.41 | 2.48 | S4 | 33.70 |
| 18 | 357 | 235 | 50.00 | -0.08 | 1.63 | R2.5 | 25.40 |
| 19 | 358 | 713 | 35.00 | -0.14 | 2.90 | R2.5 | 11.80 |
| 20 | 359 | 29 | 60.00 | | 1.12 | R4 | 29.30 |
| 21 | | | | | | | |
| 22 | | | | | | | |
| 23 | | | | | | | |
| 24 | | | | | | | |
| 25 | 361 | 7,218 | 45.00 | -0.22 | 2.37 | R2.5 | 26.50 |
| 26 | 362 | 110,869 | 40.00 | -0.09 | 1.87 | R1 | 27.40 |
| 27 | 364 | 159,699 | 40.00 | -0.88 | 2.84 | R2 | 25.00 |
| 28 | 365 | 144,631 | 40.00 | -0.63 | 2.72 | R1.5 | 25.70 |
| 29 | 366 | 60,888 | 45.00 | -0.17 | 1.91 | R2.5 | 30.40 |
| 30 | 367 | 137,747 | 35.00 | -0.21 | 2.28 | R1.5 | 24.40 |
| 31 | 368 | 86,556 | 30.00 | -0.15 | 3.17 | R1 | 18.40 |
| 32 | 369 | 50,765 | 35.00 | -0.83 | 3.60 | R3 | 20.40 |
| 33 | 370 | 21,248 | 25.00 | -0.16 | 3.45 | R0.5 | 16.30 |
| 34 | 373 | 12,589 | 25.00 | -0.54 | 3.26 | L0 | 18.20 |
| 35 | | | | | | | |
| 36 | | | | | | | |
| 37 | | | | | | | |
| 38 | | | | | | | |
| 39 | 390 | 21,605 | 50.00 | | 1.48 | R4 | 28.30 |
| 40 | 391 | 2,102 | 15.00 | | 6.67 | SQ | 8.40 |
| 41 | 391.01 | 30 | 5.00 | | 6.69 | SQ | 2.00 |
| 42 | 391.02 | 1,639 | 5.00 | | 20.00 | SQ | 1.50 |
| 43 | 392 | 14,755 | 11.00 | 1.82 | 7.27 | L0.5 | 7.60 |
| 44 | 393 | 374 | 20.00 | | 5.00 | SQ | 17.90 |
| 45 | 394 | 3,711 | 20.00 | | 4.60 | SQ | 9.70 |
| 46 | 395 | 587 | 20.00 | | 5.00 | SQ | 7.40 |
| 47 | 396 | 1,560 | 10.00 | 1.00 | 9.00 | L0 | 6.40 |
| 48 | 394 | 5,319 | 15.00 | | 6.67 | SQ | 11.20 |
| 49 | 398 | 26 | 20.00 | | 5.00 | SQ | 12.60 |
| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 183,177 | | 183,177 | |
| 2 | Operator-FERC Cost Recovery Adder | | | | |
| 3 | | | | | |
| 4 | Public Utility Fund Base Maintenance | 263,943 | | 263,943 | |
| 5 | Contribution-IL Commerce Commission | | | | |
| 6 | | | | | |
| 7 | Annual pro rata share for the Energy | 80,295 | | 80,295 | |
| 8 | Efficiency Program-IL Commerce Commission | | | | |
| 9 | | | | | |
| 10 | Professional services in connection with | | 835,040 | 835,040 | |
| 11 | regulatory matters - Electric | | | | |
| 12 | | | | | |
| 13 | Miscellaneous - Electric | | 12,095 | 12,095 | |
| 14 | | | | | |
| 15 | Professional services in connection with | | 320,462 | 320,462 | |
| 16 | regulatory matters - Gas | | | | |
| 17 | | | | | |
| 18 | Miscellaneous - Gas | | 181 | 181 | |
| 19 | | | | | |
| 20 | | | | | |
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| 45 | | | | | |
| 46 | TOTAL | 527,415 | 1,167,778 | 1,695,193 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | | Deferred to Account 182.3 | Contra Account | Amount | Deferred in Account 182.3 End of Year | Line No. |
| Department (f) | Account No. (g) | Amount (h) | (i) | (j) | (k) | (l) | |
| Electric | 928 | 183,177 | | | | | 1 |
| | | | | | | | 2 |
| | | | | | | | 3 |
| Electric | 928 | 263,943 | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| Electric | 928 | 80,295 | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| Electric | 928 | 835,040 | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| Electric | 928 | 12,095 | | | | | 13 |
| | | | | | | | 14 |
| Gas | 928 | 320,462 | | | | | 15 |
| | | | | | | | 16 |
| | | | | | | | 17 |
| Gas | 928 | 181 | | | | | 18 |
| | | | | | | | 19 |
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| | | | | | | | 44 |
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| | | 1,695,193 | | | | | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 $5,000.)
- (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 (4) | University of Missouri - Rolla |
| 2 | B (4) | University of Missouri - Columbia |
| 3 | A (6) | General RD&D Expenses |
| 4 | B (4) | NEETRAC Research Activities |
| 5 | Various | Minor Items (3) |
| 6 | | |
| 7 | Totals | |
| 8 | | |
| 9 | | |
| 10 | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 $5,000 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 $5,000 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) | | |
| | 6,937 | 930 | 6,937 | | 1 |
| | 5,202 | 930 | 5,202 | | 2 |
| 3,670 | | 930 | 3,670 | | 3 |
| | 15,774 | 588 | 15,774 | | 4 |
| 4 | 2,601 | Various | 2,605 | | 5 |
| | | | | | 6 |
| 3,674 | 30,514 | | 34,188 | | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 443,018 | | |
| 5 | Regional Market | | | |
| 6 | Distribution | 6,868,641 | | |
| 7 | Customer Accounts | 3,001,449 | | |
| 8 | Customer Service and Informational | 229,721 | | |
| 9 | Sales | 66,662 | | |
| 10 | Administrative and General | 6,483,518 | | |
| 11 | TOTAL Operation (Enter Total of lines 3 thru 10) | 17,093,009 | | |
| 12 | Maintenance | | | |
| 13 | Production | | | |
| 14 | Transmission | 171,065 | | |
| 15 | Regional Market | | | |
| 16 | Distribution | 6,130,805 | | |
| 17 | Administrative and General | 52,598 | | |
| 18 | TOTAL Maintenance (Total of lines 13 thru 17) | 6,354,468 | | |
| 19 | Total Operation and Maintenance | | | |
| 20 | Production (Enter Total of lines 3 and 13) | | | |
| 21 | Transmission (Enter Total of lines 4 and 14) | 614,083 | | |
| 22 | Regional Market (Enter Total of Lines 5 and 15) | | | |
| 23 | Distribution (Enter Total of lines 6 and 16) | 12,999,446 | | |
| 24 | Customer Accounts (Transcribe from line 7) | 3,001,449 | | |
| 25 | Customer Service and Informational (Transcribe from line 8) | 229,721 | | |
| 26 | Sales (Transcribe from line 9) | 66,662 | | |
| 27 | Administrative and General (Enter Total of lines 10 and 17) | 6,536,116 | | |
| 28 | TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 23,447,477 | 969,879 | 24,417,356 |
| 29 | Gas | | | |
| 30 | Operation | | | |
| 31 | Production-Manufactured Gas | 857,407 | | |
| 32 | Production-Nat. Gas (Including Expl. and Dev.) | | | |
| 33 | Other Gas Supply | | | |
| 34 | Storage, LNG Terminaling and Processing | | | |
| 35 | Transmission | 247,007 | | |
| 36 | Distribution | 5,116,354 | | |
| 37 | Customer Accounts | 2,899,863 | | |
| 38 | Customer Service and Informational | 130,384 | | |
| 39 | Sales | 7,462 | | |
| 40 | Administrative and General | 1,565,753 | | |
| 41 | TOTAL Operation (Enter Total of lines 31 thru 40) | 10,824,230 | | |
| 42 | Maintenance | | | |
| 43 | Production-Manufactured Gas | 136,544 | | |
| 44 | Production-Natural Gas (Including Exploration and Development) | | | |
| 45 | Other Gas Supply | | | |
| 46 | Storage, LNG Terminaling and Processing | | | |
| 47 | Transmission | 109,502 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | 3,054,031 | | |
| 49 | Administrative and General | 35,286 | | |
| 50 | TOTAL Maint. (Enter Total of lines 43 thru 49) | 3,335,363 | | |
| 51 | Total Operation and Maintenance | | | |
| 52 | Production-Manufactured Gas (Enter Total of lines 31 and 43) | 993,951 | | |
| 53 | Production-Natural Gas (Including Expl. and Dev.) (Total lines 32, | | | |
| 54 | Other Gas Supply (Enter Total of lines 33 and 45) | | | |
| 55 | Storage, LNG Terminaling and Processing (Total of lines 31 thru | | | |
| 56 | Transmission (Lines 35 and 47) | 356,509 | | |
| 57 | Distribution (Lines 36 and 48) | 8,170,385 | | |
| 58 | Customer Accounts (Line 37) | 2,899,863 | | |
| 59 | Customer Service and Informational (Line 38) | 130,384 | | |
| 60 | Sales (Line 39) | 7,462 | | |
| 61 | Administrative and General (Lines 40 and 49) | 1,601,039 | | |
| 62 | TOTAL Operation and Maint. (Total of lines 52 thru 61) | 14,159,593 | 415,281 | 14,574,874 |
| 63 | Other Utility Departments | | | |
| 64 | Operation and Maintenance | | | |
| 65 | TOTAL All Utility Dept. (Total of lines 28, 62, and 64) | 37,607,070 | 1,385,160 | 38,992,230 |
| 66 | Utility Plant | | | |
| 67 | Construction (By Utility Departments) | | | |
| 68 | Electric Plant | 9,032,642 | 773,557 | 9,806,199 |
| 69 | Gas Plant | 5,195,393 | 444,934 | 5,640,327 |
| 70 | Other (provide details in footnote): | | | |
| 71 | TOTAL Construction (Total of lines 68 thru 70) | 14,228,035 | 1,218,491 | 15,446,526 |
| 72 | Plant Removal (By Utility Departments) | | | |
| 73 | Electric Plant | 571,671 | 11,705 | 583,376 |
| 74 | Gas Plant | 38,124 | 781 | 38,905 |
| 75 | Other (provide details in footnote): | | | |
| 76 | TOTAL Plant Removal (Total of lines 73 thru 75) | 609,795 | 12,486 | 622,281 |
| 77 | Other Accounts (Specify, provide details in footnote): | | | |
| 78 | | | | |
| 79 | Other Work in Progress | 60,943 | 1,780 | 62,723 |
| 80 | | | | |
| 81 | Other Income & Deductions | 217,769 | | 217,769 |
| 82 | | | | |
| 83 | | | | |
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| 92 | | | | |
| 93 | | | | |
| 94 | | | | |
| 95 | TOTAL Other Accounts | 278,712 | 1,780 | 280,492 |
| 96 | TOTAL SALARIES AND WAGES | 52,723,612 | 2,617,917 | 55,341,529 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | 11,864,735 | 27,242,185 | 57,103,958 | 74,790,983 |
| 3 | Net Sales (Account 447) | | ( 90) | ( 16,881) | ( 29,158) |
| 4 | Transmission Rights | | | | |
| 5 | Ancillary Services | | | | |
| 6 | Other Items (list separately) | | | | |
| 7 | Inadvertent Distribution (Account 447) | | | | ( 364) |
| 8 | Inadvertent Distribution (Account 555) | | 905 | 3,273 | 5,342 |
| 9 | Revenue Sufficiency Guarantee (a/c 555) | | 42,712 | 146,693 | 197,798 |
| 10 | Deviation (Account 555) | | | | |
| 11 | Losses (Account 555) | | ( 67,591) | ( 315,069) | ( 459,971) |
| 12 | Revenue Neutrality Uplift (Account 555) | | 106,147 | 205,194 | 293,997 |
| 13 | Unaccounted for Energy (Account 555) | | | | |
| 14 | Other Energy Adjustments (Account 555) | ( 93) | 416,414 | 243,421 | 98,610 |
| 15 | RTP Non-Energy (Account 447) | | | | |
| 16 | RTP Non-Energy (Account 555) | 53,866 | 60,566 | 61,046 | 61,046 |
| 17 | Revenue Sufficiency Guarantee (a/c 447) | | | | |
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| 45 | | | | | |
| 46 | TOTAL | 11,918,508 | 27,801,248 | 57,431,635 | 74,958,283 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | | | -21 | | KWH | -441,744 |
| 2 | Reactive Supply and Voltage | | | | | KWH | |
| 3 | Regulation and Frequency Response | | | | | KWH | -1,962,236 |
| 4 | Energy Imbalance | | | | | KWH | |
| 5 | Operating Reserve - Spinning | | | | | KWH | -821,355 |
| 6 | Operating Reserve - Supplement | | | | | KWH | -90,509 |
| 7 | Other | | | 7,479,188 | | KWH | -3,366,685 |
| 8 | Total (Lines 1 thru 7) | | | 7,479,167 | | | -6,682,529 |

FOOTNOTE DATA

***Schedule Page: 398 Line No.: 1 Column: b***

Central Illinois Light Co. is a transmission owning member of the MISO RTO. CIL is not a transmission provider. CIL does not sell transmission services or ancillary services directly. Instead, CIL receives revenues from transmission services and ancillary services sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

***Schedule Page: 398 Line No.: 7 Column: d***

Amount represents Ancillary Auction charges.

***Schedule Page: 398 Line No.: 7 Column: g***

Amount represents Ancillary Auction 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 Light 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 | 952 | 2 | 19 | 515 | 335 | 32 | | 28 | 43 |
| 2 | February | 949 | 11 | 19 | 506 | 344 | 32 | | 33 | 34 |
| 3 | March | 872 | 3 | 19 | 419 | 344 | 32 | | 27 | 49 |
| 4 | Total for Quarter 1 | 2,773 | | | 1,440 | 1,023 | 96 | | 88 | 126 |
| 5 | April | 768 | 2 | 8 | 230 | 338 | 32 | | 46 | 123 |
| 6 | May | 802 | 30 | 15 | 304 | 288 | 27 | | 92 | 92 |
| 7 | June | 1,064 | 12 | 17 | 509 | 359 | 29 | | 75 | 92 |
| 8 | Total for Quarter 2 | 2,634 | | | 1,043 | 985 | 88 | | 213 | 307 |
| 9 | July | 1,140 | 27 | 17 | 524 | 416 | 29 | | 71 | 100 |
| 10 | August | 1,170 | 4 | 17 | 627 | 376 | 26 | | 74 | 67 |
| 11 | September | 1,094 | 2 | 17 | 572 | 390 | 26 | | 51 | 54 |
| 12 | Total for Quarter 3 | 3,404 | | | 1,723 | 1,182 | 81 | | 196 | 221 |
| 13 | October | 814 | 13 | 20 | 295 | 368 | 26 | | 64 | 61 |
| 14 | November | 854 | 20 | 18 | 241 | 350 | 34 | | 123 | 105 |
| 15 | December | 955 | 15 | 18 | 374 | 342 | 34 | | 121 | 84 |
| 16 | Total for Quarter 4 | 2,623 | | | 910 | 1,060 | 94 | | 308 | 250 |
| 17 | Total Year to Date/Year | 11,434 | | | 5,116 | 4,250 | 359 | | 805 | 904 |

FOOTNOTE DATA

***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 times 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 their Monthly Revenue files.

The AMIL portion of the MISO zonal transmission system includes Central Illinois Public Service Company, Central Illinois Lighting Company and Illinois Power Company.

***Schedule Page: 400 Line No.: 17 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 times 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 their Monthly Revenue files.

The AMIL portion of the MISO zonal transmission system includes Central Illinois Public Service Company, Central Illinois Lighting 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | 4,039,276 |
| 3 | Steam | | 23 | Requirements Sales for Resale (See instruction 4, page 311.) | |
| 4 | Nuclear | | 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | |
| 5 | Hydro-Conventional | | 25 | Energy Furnished Without Charge | |
| 6 | Hydro-Pumped Storage | | 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | |
| 7 | Other | 20,857 | 27 | Total Energy Losses | 123,195 |
| 8 | Less Energy for Pumping | | 28 | TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20) | 4,162,471 |
| 9 | Net Generation (Enter Total of lines 3 through 8) | 20,857 | | | |
| 10 | Purchases | 4,141,614 | | | |
| 11 | Power Exchanges: | | | | |
| 12 | Received | | | | |
| 13 | Delivered | | | | |
| 14 | Net Exchanges (Line 12 minus line 13) | | | | |
| 15 | Transmission For Other (Wheeling) | | | | |
| 16 | Received | 7,611,411 | | | |
| 17 | Delivered | 7,611,411 | | | |
| 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) | 4,162,471 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM: Central Illinois Light 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) | Day of Month (e) | Hour (f) |
|---|---|---|---|---|---|---|
| 29 | January | 390,610 | | 676 | 24 | 7-8 pm |
| 30 | February | 365,434 | | 681 | 21 | 10-11 am |
| 31 | March | 305,946 | | 609 | 3 | 6-7 pm |
| 32 | April | 286,816 | | 533 | 1 | 8-9 pm |
| 33 | May | 304,374 | | 506 | 26 | 8-9 pm |
| 34 | June | 365,096 | | 815 | 12 | 4-5 pm |
| 35 | July | 400,598 | | 857 | 17 | 4-5 pm |
| 36 | August | 392,717 | | 923 | 4 | 5-6 pm |
| 37 | September | 309,559 | | 883 | 2 | 4-5 pm |
| 38 | October | 283,302 | | 547 | 27 | 6-7 pm |
| 39 | November | 342,517 | | 563 | 17 | 6-7 pm |
| 40 | December | 415,502 | | 694 | 15 | 6-7 pm |
| 41 | TOTAL | 4,162,471 | | | | |

FOOTNOTE DATA

***Schedule Page: 401 Line No.: 22 Column: b***

Excludes 2,474,925 megawatts delivered to delivery service customers (non-energy sales). See footnote on Page 301, Line 10, Column (d) for additional information.

***Schedule Page: 401 Line No.: 27 Column: b***

Includes 665 megawatthours of unaccounted for energy.

***Schedule Page: 401 Line No.: 29 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 30 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 31 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 32 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 33 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 34 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 35 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 36 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 37 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 38 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 39 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL Energy customers only.

***Schedule Page: 401 Line No.: 40 Column: b***

Previously disclosed volumes included wheeled megawatts for others. Currently disclosed megawatts are for CIL 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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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| | | | 44 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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<br>Plant Name: (b) | FERC Licensed Project No. 0<br>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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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<br>Plant Name:<br>(d) | FERC Licensed Project No. 0<br>Plant Name:<br>(e) | FERC Licensed Project No. 0<br>Plant Name:<br>(f) | Line No. |
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| 0 | 0 | 0 | 14 |
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| 0 | 0 | 0 | 18 |
| 0 | 0 | 0 | 19 |
| 0 | 0 | 0 | 20 |
| 0.0000 | 0.0000 | 0.0000 | 21 |
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| 0 | 0 | 0 | 23 |
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| 0 | 0 | 0 | 26 |
| 0 | 0 | 0 | 27 |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.<br>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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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.<br>Plant Name:<br>(c) | FERC Licensed Project No.<br>Plant Name:<br>(d) | FERC Licensed Project No.<br>Plant Name:<br>(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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) |
|---|---|---|---|---|---|---|
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Line No. |
|---|---|---|---|---|---|---|
| | | Fuel (i) | Maintenance (j) | | | |
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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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | R.S. Wallace | Spring Bay Sub. | 138.00 | 138.00 | 1,2,3 | 11.74 | 0.01 | 1 |
| 2 | E.D. Edwards | Cat Mapleton | 138.00 | 138.00 | 1,3 | 5.79 | 0.30 | 1 |
| 3 | Lincoln-Kickapoo | IP Co Tap | 138.00 | 138.00 | 1 | 5.22 | | 1 |
| 4 | Fargo | Hines | 138.00 | 138.00 | 1,4 | 9.38 | | 1 |
| 5 | Tower "17" | Tremont Jct. | | 138.00 | 2 | 2.75 | | 1 |
| 6 | R.S. Wallace | Tazewell | 138.00 | 138.00 | 1,3 | 6.65 | 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 | R.S. Wallace | Cat E. Peoria | 138.00 | 138.00 | 3 | | 0.73 | 2 |
| 11 | E.D. Edwards | Tazewell | 138.00 | 345.00 | 3 | | 9.00 | 2 |
| 12 | E.D. Edwards | Tazewell | 138.00 | 138.00 | 3 | 9.07 | | 2 |
| 13 | E.D. Edwards | Cat E. Peoria | 138.00 | 138.00 | 1,3 | 7.82 | 1.65 | 2 |
| 14 | Cat #2 Sub | Tazewell | 138.00 | 138.00 | 1,2,3 | | 10.87 | 2 |
| 15 | Fargo | Moss Cat | 138.00 | 138.00 | 3 | 13.73 | | 2 |
| 16 | Tazewell/Lincoln | E. Springfield | 138.00 | 138.00 | 1,2,3 | 70.05 | | 2 |
| 17 | E.D. Edwards | CE Co Tap | 138.00 | 138.00 | 1,3 | 1.21 | 0.30 | 2 |
| 18 | E.D. Edwards | Cat Mapleton Fargo | 138.00 | 138.00 | 2,3 | 23.19 | | 2 |
| 19 | Moss Cat | Hallock | 138.00 | 138.00 | 1,3 | 6.89 | 2.20 | 2 |
| 20 | R.S. Wallace | Keystone | 138.00 | 138.00 | 3 | 5.23 | | 2 |
| 21 | E.D. Edwards | Keystone | 138.00 | 138.00 | 1 | 3.27 | | 1 |
| 22 | E. Springfield | Elkhart | 138.00 | 138.00 | 2 | 14.63 | | 1 |
| 23 | Spring Bay Sub. | IP Structure "82" | 138.00 | 138.00 | 2,3 | 0.22 | | 1 |
| 24 | Hallock | Richland | 138.00 | 138.00 | 3 | 9.97 | | 1 |
| 25 | Kickapoo | McGrath/Limit | 138.00 | 138.00 | 1 | 3.12 | | 1 |
| 26 | Limit Sub. | Casimir Sub | 34.50 | 138.00 | 1 | 4.27 | | 1 |
| 27 | Tazewell | Tower "5" | 345.00 | 345.00 | 3 | | 0.64 | 1 |
| 28 | Tazewell | Tower "5" | 345.00 | 345.00 | 3 | 0.64 | | 1 |
| 29 | Duck Creek | Tazewell | 345.00 | 345.00 | 1,3,4 | 34.58 | | 2 |
| 30 | Duck Creek | Ipava | 345.00 | 345.00 | 2 | 11.74 | | 1 |
| 31 | Lincoln | Heyworth | 34.50 | 138.00 | 1 | 7.97 | | 1 |
| 32 | E.D. Edwards | Bartonville | | 138.00 | 1,3 | | 4.59 | 2 |
| 33 | | | | | | | | |
| 34 | | | | | | | | |
| 35 | | | | | | | | |
| 36 | | | | | TOTAL | 287.85 | 63.93 | 47 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 636 ACSR | | | | | | | | 1 |
| 927.2 ACAR | | | | | | | | 2 |
| 477 ACSR | | | | | | | | 3 |
| 927.2 ACAR | | | | | | | | 4 |
| 477 ACSR | | | | | | | | 5 |
| VARIOUS | | | | | | | | 6 |
| 927.2 ACAR | | | | | | | | 7 |
| VARIOUS | | | | | | | | 8 |
| 927.2 ACAR | | | | | | | | 9 |
| 927.2 ACAR | | | | | | | | 10 |
| 954 ACSR | | | | | | | | 11 |
| VARIOUS | | | | | | | | 12 |
| VARIOUS | | | | | | | | 13 |
| VARIOUS | | | | | | | | 14 |
| 927.2 ACAR | | | | | | | | 15 |
| VARIOUS | | | | | | | | 16 |
| VARIOUS | | | | | | | | 17 |
| 927.2 ACAR | | | | | | | | 18 |
| 927.2 ACAR | | | | | | | | 19 |
| 927.2 ACAR | | | | | | | | 20 |
| 2-927.2 ACAR | | | | | | | | 21 |
| 477 ACSR | | | | | | | | 22 |
| 636 ACSR | | | | | | | | 23 |
| VARIOUS | | | | | | | | 24 |
| VARIOUS | | | | | | | | 25 |
| 2-266 ACSR | | | | | | | | 26 |
| 1277 ACAR | | | | | | | | 27 |
| 1277 ACAR | | | | | | | | 28 |
| 954 ACSR | | | | | | | | 29 |
| 954 ACSR | | | | | | | | 30 |
| 2-266.8 ACSR | | | | | | | | 31 |
| 927.2 ACAR | | | | | | | | 32 |
| | 4,266,796 | 50,973,153 | 55,239,949 | | 941,809 | | 941,809 | 33 |
| | | | | | | | | 34 |
| | | | | | | | | 35 |
| | 4,266,796 | 50,973,153 | 55,239,949 | | 941,809 | | 941,809 | 36 |

FOOTNOTE DATA

***Schedule Page: 422 Line No.: 33 Column: j***

Land costs available in total only.

***Schedule Page: 422 Line No.: 33 Column: k***

Construction and other costs available in total only.

***Schedule Page: 422 Line No.: 33 Column: n***

Maintenance Expenses available in total 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | LINE COST | | | | | Line |
|---|---|---|---|---|---|---|---|---|---|
| Size (h) | Specification (i) | Configuration and Spacing (j) | KV (Operating) (k) | Land and Land Rights (l) | Poles, Towers and Fixtures (m) | Conductors and Devices (n) | Asset Retire. Costs (o) | Total (p) | 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (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. | 69.00 | 12.50 | |
| 10 | Hines - Peoria Heights | Unattended Distr. | 138.00 | 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 | |

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|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/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 | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (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 | Tazewell - Groveland | Unattended Distr | 69.00 | 13.80 | |
| 12 | North Morton - Morton | Unattended Distr | 69.00 | 12.50 | |
| 13 | Sidney - Sidney | Unattended Distr. | 69.00 | 12.50 | |
| 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 | 16 Substations (10 MVA & over) | Unattended Trans | | | |
| 21 | 70 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 | | | | | |
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| 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<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Central Illinois Light Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/17/2009 | End of 2008/Q4 |

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 | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | |
| 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 |
| 13 | 1 | | | | | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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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) | |
| 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 |
| 33 | 1 | | | | | 11 |
| 13 | 2 | | | | | 12 |
| 13 | 1 | | | | | 13 |
| | | | | | | 14 |
| 234 | 40 | | | | | 15 |
| 9 | 1 | | | | | 16 |
| | | | | | | 17 |
| | | | | | | 18 |
| 1424 | 7 | | | | | 19 |
| 2516 | 17 | | | | | 20 |
| 1678 | 87 | | | | | 21 |
| 234 | 40 | | | | | 22 |
| 9 | 1 | | | | | 23 |
| | | | | | | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
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| | | | | | | 33 |
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| | | | | | | 40 |

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