THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 05/31/2014)

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
Kansas City Power & Light Company	End of 2011/Q3

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 Kansas City Power & Light Company	02 Year/Period of Report End of 2011/Q3
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1200 Main, Kansas City, Missouri 64105	
05 Name of Contact Person Lori A. Wright	06 Title of Contact Person Vice President & Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 1200 Main, Kansas City, Missouri 64105	

08 Telephone of Contact Person, *Including Area Code* (816) 556-2200	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 11/29/2011

QUARTERLY 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 Lori A. Wright 02 Title Vice President & Controller	03 Signature Lori A. Wright	04 Date Signed *(Mo, Da, Yr)* 11/29/2011

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.

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	Important Changes During the Quarter	108-109	
2	Comparative Balance Sheet	110-113	
3	Statement of Income for the Quarter	114-117	
4	Statement of Retained Earnings for the Quarter	118-119	
5	Statement of Cash Flows	120-121	
6	Notes to Financial Statements	122-123	
7	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122 (a)(b)	
8	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
9	Electric Plant In Service and Accum Provision For Depr by Function	208	
10	Transmission Service and Generation Interconnection Study Costs	231	
11	Other Regulatory Assets	232	
12	Other Regulatory Liabilities	278	
13	Elec Operating Revenues (Individual Schedule Lines 300-301)	300-301	
14	Regional Transmission Service Revenues (Account 457.1)	302	NA
15	Electric Prod, Other Power Supply Exp, Trans and Distrib Exp	324	
16	Electric Customer Accts, Service, Sales, Admin and General Expenses	325	
17	Transmission of Electricity for Others	328-330	
18	Transmission of Electricity by ISO/RTOs	331	NA
19	Transmission of Electricity by Others	332	
20	Deprec, Depl and Amort of Elec Plant (403,403.1,404,and 405) (except A	338	
21	Amounts Included in ISO/RTO Settlement Statements	397	
22	Monthly Peak Loads and Energy Output	399	
23	Monthly Transmission System Peak Load	400	
24	Monthly ISO/RTO Transmission System Peak Load	400a	NA

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None
2. None
3. None
4. None
5. None
6. Please see pages 122-123 for Notes to Financial Statements, Note 8 Short-Term Borrowings and Short-Term Bank Lines of Credit and Note 9 Long-Term Debt for obligations incurred during the third quarter of 2011.
7. None
8. None
9. **Legal and Regulatory Proceedings/Actions:**

   Please see pages 122-123 for Notes to Financial Statements, Note 5 Regulatory Matters, Note Note 10 Commitments and Contingencies detailing 2011 Environmental Matters and Note 11 for Legal Proceedings that were still active at September 30, 2011.
10. See 13.
11. Reserved
12. See the Notes to Financial Statements included on pages 122-123.
13. On August 15, 2011, Michael W. Cline ceased serving as Vice President-Investor Relations and Treasurer. On August 15, 2011, Kevin E. Bryant ceased serving as Vice President-Strategy and Risk Management and became Vice President-Investor Relations and Treasurer.

    On August 31, 2011, William H. Downey ceased serving as Executive Vice Chairman and Director; on September 1, 2011, Terry Bassham became a Director.
14. Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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	7,762,577,725	7,540,925,935
3	Construction Work in Progress (107)	200-201	181,916,554	227,542,942
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,944,494,279	7,768,468,877
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,210,662,284	3,104,681,195
6	Net Utility Plant (Enter Total of line 4 less 5)		4,733,831,995	4,663,787,682
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	19,294,669	8,831,886
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		2,771,026	39,537,985
9	Nuclear Fuel Assemblies in Reactor (120.3)		92,442,408	78,870,218
10	Spent Nuclear Fuel (120.4)		87,570,507	83,085,759
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	124,814,603	131,093,239
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		77,264,007	79,232,609
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,811,096,002	4,743,020,291
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		9,060,331	8,988,611
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,723,792	4,528,545
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	9,069,289	7,111,324
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)		1,333,963	1,786,664
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		125,490,511	129,179,248
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)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		140,230,302	142,537,302
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,101,767	2,311,354
36	Special Deposits (132-134)		158,629	401,797
37	Working Fund (135)		5,975	10,000
38	Temporary Cash Investments (136)		0	11,560
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		0	0
41	Other Accounts Receivable (143)		67,461,235	71,097,203
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		0	0
43	Notes Receivable from Associated Companies (145)		132,886,180	63,900,770
44	Accounts Receivable from Assoc. Companies (146)		14,212,272	30,827,697
45	Fuel Stock (151)	227	41,980,632	44,875,683
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	88,542,512	85,976,845
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	4,101	0

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	10,194,835	8,433,844
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		9,492,319	9,349,503
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		616,156	0
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		53,250,154	19,471,728
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)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		421,906,767	336,667,984
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		19,333,670	19,785,436
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	790,288,933	771,119,608
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)		702,191	644,454
77	Temporary Facilities (185)		1,914	595
78	Miscellaneous Deferred Debits (186)	233	10,141,605	5,627,822
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	107,450
81	Unamortized Loss on Reaquired Debt (189)		6,508,163	5,029,032
82	Accumulated Deferred Income Taxes (190)	234	539,198,973	499,012,271
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,366,175,449	1,301,326,668
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,739,408,520	6,523,552,245

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	487,041,247	487,041,247
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,076,114,704	1,076,114,704
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	514,620,723	468,767,656
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	6,069,289	4,111,325
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)	-32,490,510	-36,401,942
16	Total Proprietary Capital (lines 2 through 15)		2,051,355,453	1,999,632,990
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,178,668,000	1,778,668,000
19	(Less) Reaquired Bonds (222)	256-257	112,730,000	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	2,920,957	3,271,797
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,339,508	1,893,266
24	Total Long-Term Debt (lines 18 through 23)		2,064,519,449	1,780,046,531
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,003,697	2,049,939
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,679,912	3,008,311
29	Accumulated Provision for Pensions and Benefits (228.3)		426,080,781	407,316,715
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		132,188,163	129,729,039
35	Total Other Noncurrent Liabilities (lines 26 through 34)		563,952,553	542,104,004
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		10,500,000	263,500,000
38	Accounts Payable (232)		158,055,625	220,777,708
39	Notes Payable to Associated Companies (233)		395,110	1,960,000
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		5,919,012	6,282,681
42	Taxes Accrued (236)	262-263	66,148,580	21,290,207
43	Interest Accrued (237)		34,090,373	26,216,879
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		7,823,708	6,028,104
48	Miscellaneous Current and Accrued Liabilities (242)		35,107,475	25,584,242
49	Obligations Under Capital Leases-Current (243)		60,490	56,988
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		318,100,373	571,696,809
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,381,726	1,855,709
57	Accumulated Deferred Investment Tax Credits (255)	266-267	128,383,720	129,361,188
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	49,169,086	50,934,361
60	Other Regulatory Liabilities (254)	278	238,906,926	246,374,487
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)		1,146,648,095	1,032,281,747
64	Accum. Deferred Income Taxes-Other (283)		176,991,139	169,264,419
65	Total Deferred Credits (lines 56 through 64)		1,741,480,692	1,630,071,911
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,739,408,520	6,523,552,245

Schedule Page: 112 Line No.: 37 Column: c

Per Docket No. ER10-230-000, FERC transmission formula rate, the 12-month average daily balance of short-term debt at September 30, 2011 was $308,005,614.

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,220,549,036	1,194,647,556	506,377,007	486,438,998
3	Operating Expenses					
4	Operation Expenses (401)	320-323	591,807,680	524,056,139	217,355,381	190,974,943
5	Maintenance Expenses (402)	320-323	90,956,939	82,339,773	28,754,156	23,175,696
6	Depreciation Expense (403)	336-337	120,389,470	126,390,640	41,093,767	43,743,615
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	792,171	856,911	264,057	264,637
8	Amort. & Depl. of Utility Plant (404-405)	336-337	26,497,369	65,710,146	4,280,733	22,554,808
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)					
13	(Less) Regulatory Credits (407.4)		7,107,524	6,700,666	2,402,340	2,242,898
14	Taxes Other Than Income Taxes (408.1)	262-263	109,391,120	99,292,304	41,620,074	37,213,540
15	Income Taxes - Federal (409.1)	262-263	-13,543,242	24,120,641	-7,321,531	-16,039,932
16	- Other (409.1)	262-263	-733,059	5,130,384	-289,629	-2,547,611
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	101,317,214	69,922,002	73,050,985	76,183,406
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	13,213,801	4,835,388	9,897,295	-808,137
19	Investment Tax Credit Adj. - Net (411.4)	266	-954,335	-5,405,760	-496,379	-525,421
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)		733,001			
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		6,315,354	5,843,755	2,138,284	1,978,261
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,011,182,355	986,720,881	388,150,263	375,541,181
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		209,366,681	207,926,675	118,226,744	110,897,817

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
1,220,549,036	1,194,647,556					2
						3
591,807,680	524,056,139					4
90,956,939	82,339,773					5
120,389,470	126,390,640					6
792,171	856,911					7
26,497,369	65,710,146					8
						9
						10
						11
						12
7,107,524	6,700,666					13
109,391,120	99,292,304					14
-13,543,242	24,120,641					15
-733,059	5,130,384					16
101,317,214	69,922,002					17
13,213,801	4,835,388					18
-954,335	-5,405,760					19
						20
						21
733,001						22
						23
6,315,354	5,843,755					24
1,011,182,355	986,720,881					25
209,366,681	207,926,675					26

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)		209,366,681	207,926,675	118,226,744	110,897,817
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		3,027,665	2,914,111	1,201,246	1,151,278
34	(Less) Expenses of Nonutility Operations (417.1)		298,931	339,256	169,119	166,511
35	Nonoperating Rental Income (418)		-119,021	-41,244	-48,315	-41,188
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,957,964	3,044,264	344,178	1,325,663
37	Interest and Dividend Income (419)		638,056	489,910	464,576	193,966
38	Allowance for Other Funds Used During Construction (419.1)		-46,337	21,686,868	-3,323	5,605,557
39	Miscellaneous Nonoperating Income (421)		497,500	515,931	165,833	160,910
40	Gain on Disposition of Property (421.1)		171,943	29,343	-140	-1,207
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,828,839	28,299,927	1,954,936	8,228,468
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		3,938	184,018	-140	160,579
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,630,091	1,960,028	322,033	789,284
46	Life Insurance (426.2)		436,649	-107,472	191,187	-316,994
47	Penalties (426.3)		14,184	13,477		12,510
48	Exp. for Certain Civic, Political & Related Activities (426.4)		569,798	584,754	164,198	216,450
49	Other Deductions (426.5)		15,583,144	17,900,143	5,956,409	9,992,784
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		18,237,804	20,534,948	6,633,687	10,854,613
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	49,378	47,288	16,650	15,876
53	Income Taxes-Federal (409.2)	262-263	-4,777,575	-5,108,849	-2,039,869	-2,488,598
54	Income Taxes-Other (409.2)	262-263	-862,755	-922,560	-368,353	-449,382
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	582,851	1,178,172		1,178,172
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		23,133	23,133	7,711	7,711
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-6,196,936	-7,185,426	-2,399,283	-4,107,987
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-6,212,029	14,950,405	-2,279,468	1,481,842
61	Interest Charges					
62	Interest on Long-Term Debt (427)		86,346,229	88,439,156	28,778,747	29,459,927
63	Amort. of Debt Disc. and Expense (428)		2,493,774	1,658,803	826,046	726,343
64	Amortization of Loss on Reaquired Debt (428.1)		371,076	300,050	135,102	102,370
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)		78,996	24,862	20,089	10,855
68	Other Interest Expense (431)		-7,356,656	-6,191,075	1,214,432	-4,594,485
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,589,798	21,344,106	395,107	5,888,241
70	Net Interest Charges (Total of lines 62 thru 69)		80,343,621	62,887,690	30,579,309	19,816,769
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		122,811,031	159,989,390	85,367,967	92,562,890
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)		122,811,031	159,989,390	85,367,967	92,562,890

Schedule Page: 114 Line No.: 68 Column: c

Per Case No. ER10-230-000, FERC transmission formula rate case, additional detail for other interest expense has been provided below:

	Q1	Q2	Q3	Total YTD Q3
431015 Commitment Exp-ST Loans	693,858	700,822	809,115	2,203,795
431016 Interest on Unsecur Notes	301,551	384,578	296,173	982,302
All Other Interest Expense	(7,783,149)	(2,868,748)	109,144	(10,542,753)
Total Other Interest Expense	(6,787,740)	(1,783,348)	1,214,432	(7,356,656)

Schedule Page: 114 Line No.: 68 Column: d

Per Case No. ER10-230-000, FERC transmission formula rate case, additional detail for other interest expense has been provided below:

	Q1	Q2	Q3	Total YTD Q3
431015 Commitment Exp-ST Loans	162,060	213,676	548,354	924,090
431016 Interest on Unsecur Notes	207,878	305,077	267,108	780,063
All Other Interest Expense	(1,257,801)	(1,227,481)	(5,409,946)	(7,895,228)
Total Other Interest Expense	(887,863)	(708,728)	(4,594,484)	(6,191,075)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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		468,767,656	403,870,643
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		120,853,067	156,945,126
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				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-75,000,000	(70,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-75,000,000	(70,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		514,620,723	490,815,769
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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)		514,620,723	490,815,769
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	122,811,031	159,989,390
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	146,886,839	192,100,786
5	Amortization of		
6	Nuclear Fuel	13,524,475	19,678,936
7	Other	8,916,155	8,024,924
8	Deferred Income Taxes (Net)	87,520,562	63,908,442
9	Investment Tax Credit Adjustment (Net)	-977,468	-5,428,893
10	Net (Increase) Decrease in Receivables	-40,138,394	-51,944,038
11	Net (Increase) Decrease in Inventory	-1,431,607	-7,123,502
12	Net (Increase) Decrease in Allowances Inventory	-4,101	
13	Net Increase (Decrease) in Payables and Accrued Expenses	3,291,211	-26,325,891
14	Net (Increase) Decrease in Other Regulatory Assets	-22,507,054	-22,219,477
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,959,489	2,134,962
16	(Less) Allowance for Other Funds Used During Construction	-46,337	21,686,868
17	(Less) Undistributed Earnings from Subsidiary Companies	1,957,964	3,044,264
18	Other (provide details in footnote):	4,638,625	68,123,263
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	318,659,158	376,187,770
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-226,702,877	-360,409,951
27	Gross Additions to Nuclear Fuel	-11,555,871	-31,710,886
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	19,176	-165,789
30	(Less) Allowance for Other Funds Used During Construction	46,337	-21,686,868
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-238,285,909	-370,599,758
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)	-15,540,867	-78,343,917
45	Proceeds from Sales of Investment Securities (a)	12,993,374	75,588,622

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Salvage and Removal	-9,268,673	-5,704,570
55	Net Money Pool Lending	-18,805,100	6,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-268,907,175	-373,059,623
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	397,432,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		22,926,000
67	Other (provide details in footnote):		
68	Net Money Pool Borrowings	-1,565,000	34,776,823
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	395,867,000	57,702,823
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-113,073,697	-220,106
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Issuance Costs	-3,770,458	-5,025,450
78	Net Decrease in Short-Term Debt (c)	-253,000,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-75,000,000	-70,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-48,977,155	-17,542,733
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	774,828	-14,414,586
87			
88	Cash and Cash Equivalents at Beginning of Period	2,332,914	16,600,794
89			
90	Cash and Cash Equivalents at End of period	3,107,742	2,186,208

Schedule Page: 120 Line No.: 90 Column: b

	2011 3rd Quarter	2010 3rd Quarter
Balance Sheet, pages 110-111:		
Line No. 35 - Cash (131)	$3,101,767	$1,905,702
Line No. 36 - Special Deposits (132-134)	158,629	229,384
Line No. 37 - Working Fund (135)	5,975	44,098
Line No. 38 - Temporary Cash Investments (136)	-	236,408
Total Balance Sheet	**$3,266,371**	**$2,415,592**
Less: Funds on Deposit in 134, not considered Cash and Cash Equivalents	(158,629)	(229,384)
Cash and Cash Equivalents at End of Period	**$3,107,742**	**$2,186,208**

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.

The following is an update to the Notes that follow:

Regarding Note 9, Long-Term Debt, KCP&L repaid its $150.0 million of 6.50% senior notes that matured on November 15, 2011.

Regarding Note 10, Commitments and Contingencies, Collaboration Agreement, during November 2011, KCP&L entered into a 20-year power purchase agreement for approximately 100 MW of wind generation beginning in 2013.

KANSAS CITY POWER & LIGHT COMPANY

Notes to Financial Statements
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization
The terms "Company" and "KCP&L" are used throughout this report and refer to Kansas City Power & Light Company. KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L is a wholly owned subsidiary of Great Plains Energy Incorporated (Great Plains Energy). Great Plains Energy also owns KCP&L Greater Missouri Operations Company (GMO), a regulated utility.

Basis of Accounting
The accounting records of Kansas City Power & Light Company (KCP&L) are maintained in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases. The accompanying financial statements have been prepared in accordance with the accounting requirements of these regulators, which differ from Generally Accepted Accounting Principles (GAAP). KCP&L classifies certain items in its accompanying Comparative Balance Sheet (primarily the components of accumulated deferred income taxes, certain miscellaneous current and accrued liabilities and current maturities of long-term debt) in a manner different than that required by GAAP. In addition, in accordance with regulatory reporting requirements, KCP&L accounts for its investments in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of these subsidiaries, as required by GAAP.

Dividends Declared
In November 2011, KCP&L's Board of Directors declared a cash dividend payable to Great Plains Energy of $25 million payable on December 19, 2011.

2. SUPPLEMENTAL CASH FLOW INFORMATION

Other Operating Activities

Year to Date September 30	**2011**	**2010**
	(millions)	
Deferred refueling outage costs	$ (23.8)	$ 7.9
Nuclear decommissioning expense	2.5	2.8
Pension and post-retirement benefit obligations	32.1	31.1
Uncertain tax positions	(10.1)	(1.6)
Other	3.9	27.9
Total other operating activities	$ 4.6	$ 68.1
Cash paid during the period:		
Interest	$ 74.6	$ 60.3
Income taxes	$ 0.1	$ 68.7
Non-cash investing activities:		
Liabilities assumed for capital expenditures	$ 30.7	$ 31.6

3. RECEIVABLES

KCP&L's other receivables at September 30, 2011, and December 31, 2010, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables.

KCP&L sells all of its retail electric accounts receivable to its wholly owned subsidiary, Kansas City Power & Light Receivables Company (Receivables Company), which in turn sells an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. KCP&L sells its receivables at a fixed price based upon the expected cost of funds and charge-offs. These costs comprise KCP&L's loss on the sale of accounts receivable. KCP&L services the receivables and receives an annual servicing fee of 1.5% of the outstanding principal amount of the receivables sold to Receivables Company. KCP&L does not recognize a servicing asset or liability because management determined the collection agent fee earned by KCP&L approximates market value. In September 2011, the agreement was extended to September 2014 and amended to allow for $110 million in aggregate outstanding principal amount at any time.

Information regarding KCP&L's sale of accounts receivable to Receivables Company is reflected in the following tables.

Three Months Ended September 30, 2011	**KCP&L**	**Receivables Company**
	(millions)	
Receivables (sold) purchased	$ (468.8)	$ 468.8
Gain (loss) on sale of accounts receivable [(a)]	(5.9)	5.8
Servicing fees	0.9	(0.9)
Fees to outside investor	-	(0.3)
Cash flows during the period		
Cash from customers transferred to Receivables Company	(463.4)	463.4
Cash paid to KCP&L for receivables purchased	457.6	(457.6)
Servicing fees	0.9	(0.9)
Interest on intercompany note	0.2	(0.2)

Year to Date September 30, 2011	**KCP&L**	**Receivables Company**
	(millions)	
Receivables (sold) purchased	$ (1,108.4)	$ 1,108.4
Gain (loss) on sale of accounts receivable [(a)]	(14.0)	13.6
Servicing fees	2.0	(2.0)
Fees to outside investor	-	(0.9)
Cash flows during the period		
Cash from customers transferred to Receivables Company	(1,081.6)	1,081.6
Cash paid to KCP&L for receivables purchased	1,068.0	(1,068.0)
Servicing fees	2.0	(2.0)
Interest on intercompany note	0.4	(0.4)

Three Months Ended September 30, 2010	**KCP&L**	**Receivables Company**
	(millions)	
Receivables (sold) purchased	$ (442.0)	$ 442.0
Gain (loss) on sale of accounts receivable [(a)]	(5.6)	5.4
Servicing fees	0.8	(0.8)
Fees to outside investor	-	(0.3)
Cash flows during the period		
Cash from customers transferred to Receivables Company	(430.9)	430.9
Cash paid to KCP&L for receivables purchased	425.5	(425.5)
Servicing fees	0.8	(0.8)
Interest on intercompany note	0.2	(0.2)

Year to Date September 30, 2010	**KCP&L**	**Receivables Company**
	(millions)	
Receivables (sold) purchased	$ (1,067.7)	$ 1,067.7
Gain (loss) on sale of accounts receivable [(a)]	(13.5)	12.9
Servicing fees	1.9	(1.9)
Fees to outside investor	-	(0.9)
Cash flows during the period		
Cash from customers transferred to Receivables Company	(1,029.8)	1,029.8
Cash paid to KCP&L for receivables purchased	1,016.9	(1,016.9)
Servicing fees	1.9	(1.9)
Interest on intercompany note	0.4	(0.4)

[(a)] Any net gain (loss) is the result of the timing difference inherent in collecting receivables and over the life of the agreement will net to zero.

4. NUCLEAR PLANT

KCP&L owns 47% of Wolf Creek Generating Station (Wolf Creek), its only nuclear generating unit. Wolf Creek is located in Coffey County, Kansas, just northeast of Burlington, Kansas. Wolf Creek's operating license expires in 2045. Wolf Creek is regulated by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety-related requirements. Wolf Creek is operating in the category of nuclear plants receiving the lowest level of NRC oversight.

In March 2011, the NRC established a task force to conduct a 90-day review and a longer-term review of U.S. nuclear power plant safety in the aftermath of a March 11, 2011 earthquake and tsunami that eventually resulted in station blackout and a level 7 event on the International Nuclear and Radiological Event Scale (the highest level event on the scale) at Japan's Fukushima Daiichi nuclear power plant. On July 12, 2011, the task force issued an extensive report on the ramifications of the Fukushima earthquake/tsunami for nuclear power plant regulation in the U.S. In October 2011, the NRC received recommendations from the NRC staff on how to proceed with the task force report. The recommendations break down the task force report into three tiers of actions. The first tier of recommendations includes actions that the nuclear industry has already taken or believes need near-term attention. The second tier recommendations require further study before action can be taken and the third tier recommendations require NRC rulemaking, additional study and stakeholder involvement to finalize the specific details. The timing and effects of any NRC action cannot be determined at this time.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. KCP&L pays the DOE a quarterly fee of one-tenth of a cent for each kWh of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. These disposal costs are charged to fuel expense. In March 2010, the DOE filed a motion to withdraw its application to the NRC to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada, which would bring the licensing process to an end. An NRC board denied the DOE's motion to withdraw its application in June 2010, and the DOE appealed that decision to the full NRC in July 2010. In September 2011, the NRC issued an evenly split decision on the appeal and also ordered the licensing board to close out its work on the DOE's application by the end of September 2011 due to a lack of funding. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025, and believes it will be able to expand on-site storage as needed past 2025. Management cannot predict when, or if, an alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity. See Note 11 for a related legal proceeding.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste (Class A waste) at an existing third-party repository in Utah. Management expects that the site located in Utah will remain available to Wolf Creek for disposal of its Class A waste. Wolf Creek has contracted with a waste processor that will process, take title and store in another state most of the remainder of Wolf Creek's low-level radioactive waste (Classes B and C waste, which is higher in radioactivity but much lower in volume). Should on-site waste storage be needed in the future, Wolf Creek has current storage capacity on site for about four years' generation of Classes B and C waste and believes it will be able to expand that storage capacity as needed if it becomes necessary to do so.

Nuclear Plant Decommissioning Costs

The MPSC and KCC require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years and to propose funding levels. The most recent study was submitted to the MPSC and KCC in August 2011 and is the basis for the current cost of decommissioning estimates in the following table. Funding levels included in KCP&L retail rates have not changed.

	Total Station	KCP&L's 47% Share
	(millions)	
Current cost of decommissioning (in 2011 dollars)	$ 630	$ 296
Future cost of decommissioning (in 2045-2053 dollars) [a]	2,455	1,154
Annual escalation factor	3.73%	
Annual return on trust assets [b]	6.89%	

[a] Total future cost over an eight year decommissioning period.

[b] The 6.89% rate of return is through 2025. The rate then systematically decreases through 2053 to 1.81% based on the assumption that the fund's investment mix will become increasingly more conservative as the decommissioning period approaches.

Nuclear Decommissioning Trust Fund

The following table summarizes the change in KCP&L's nuclear decommissioning trust fund.

	September 30 2011	December 31 2010
Decommissioning Trust	(millions)	
Beginning balance January 1	$ 129.2	$ 112.5
Contributions	2.5	3.7
Earned income, net of fees	4.0	2.0
Net realized gains	0.3	6.7
Net unrealized gains (losses)	(10.5)	4.3
Ending balance	$ 125.5	$ 129.2

The nuclear decommissioning trust is reported at fair value on the balance sheets and is invested in assets as detailed in the following table.

	September 30 2011				December 31 2010			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(millions)							
Equity securities	$ 75.3	$ 6.5	$ (6.6)	$ 75.2	$ 73.4	$ 13.1	$ (1.0)	$ 85.5
Debt securities	42.7	4.4	(0.2)	46.9	38.1	2.6	(0.1)	40.6
Other	3.4	-	-	3.4	3.1	-	-	3.1
Total	$ 121.4	$ 10.9	$ (6.8)	$ 125.5	$ 114.6	$ 15.7	$ (1.1)	$ 129.2

The weighted average maturity of debt securities held by the trust at September 30, 2011, was approximately 7 years. The costs of securities sold are determined on the basis of specific identification. The following table summarizes the realized gains and losses from the sale of securities in the nuclear decommissioning trust fund.

	Three Months Ended September 30		Year to Date September 30	
	2011	2010	2011	2010
	(millions)			
Realized gains	$ 0.2	$ 0.2	$ 1.0	$ 7.2
Realized losses	-	(0.1)	(0.7)	(0.6)

5. REGULATORY MATTERS

KCP&L Kansas Rate Case Proceedings

In November 2010, KCC issued an order, effective December 1, 2010, for KCP&L, authorizing an increase in annual revenues of $21.8 million, a return on equity of 10.0%, an equity ratio of approximately 49.7% and a Kansas jurisdictional rate base of $1.781 billion. The annual revenue increase was subsequently adjusted by KCC in a January 2011 reconsideration order to $22.0 million. In February 2011, KCC issued an order granting KCP&L and another party to the case their respective petitions for reconsideration regarding rate case expenses and therefore, approximately $1.4

million of the annual revenue increase is considered as interim subject to refund or true-up pending the outcome of the reconsideration proceedings regarding rate case expenses. A hearing was held in September 2011 with a decision expected in the fourth quarter of 2011. The rates authorized by KCC are effective unless and until modified by KCC or stayed by a court.

KCP&L Missouri Rate Case Proceedings

On June 4, 2010, KCP&L filed a request with the MPSC to increase its Missouri retail electric annual revenues by $92.1 million. The request was ultimately adjusted during the rate case proceedings by KCP&L to $66.5 million as the net result of lower fuel and purchased power costs and other updates to the case. KCP&L's initial and updated requests reflected, among other things, a proposed annual offset to its revenue requirement for the Missouri jurisdictional portion of KCP&L's annual non-firm wholesale electric sales margin (wholesale margin offset); the final update included a proposed wholesale margin offset of approximately $29.4 million. On April 12, 2011, the MPSC issued its order and on April 14, 2011, the MPSC Staff filed a report which quantified the authorized revenue increase as approximately $34.8 million on an annual basis, which reflects a wholesale margin offset of approximately $45.9 million and authorizes a return on equity of 10.0%, an equity ratio of approximately 46.3% and a Missouri jurisdictional rate base of approximately $2.0 billion. If the actual Missouri jurisdiction wholesale margin amount exceeds the $45.9 million level reflected in the MPSC order, the difference will be recorded as a regulatory liability and will be returned, with interest, to KCP&L Missouri customers in a future rate case. The MPSC order provides the opportunity for KCP&L to retain a larger amount of non-firm wholesale electric sales margin than KCP&L proposed; however, there are no assurances that KCP&L will achieve the $45.9 million wholesale margin offset amount and there are no means for KCP&L to recover any shortfall through its retail rates. The rates established by the MPSC order took effect on May 4, 2011.

As a result of disallowances in the MPSC order, KCP&L recognized losses of $1.5 million for construction costs related to Iatan No. 2 and the Iatan No. 1 environmental project year to date September 30, 2011. KCP&L also recorded a $2.4 million loss for other disallowed costs in the MPSC order.

In a related order, the MPSC required KCP&L and GMO to apply to the Internal Revenue Service (IRS) to reallocate approximately $26.5 million of Iatan No. 2 qualifying advance coal project tax credits from KCP&L to GMO. KCP&L and GMO did apply to the IRS but in September 2011, the IRS denied KCP&L's and GMO's request. The MPSC has indicated it will consider the ratemaking treatment of the tax credits in a future rate case. Certain ratemaking treatments that may be pursued by the MPSC could trigger the loss or repayment to the IRS of a portion of unamortized deferred investment tax credits. At September 30, 2011, KCP&L had $128.4 million of unamortized deferred investment tax credits.

SPP and NERC Inquiries

The Southwest Power Pool, Inc. (SPP) conducted a compliance inquiry regarding a transmission system outage that occurred in the St. Joseph, Missouri area in the summer of 2009. The North American Electric Reliability Corporation (NERC) is also investigating the circumstances surrounding this transmission system outage. The outcome of the outage inquiry cannot be predicted at this time.

Regulatory Assets and Liabilities

KCP&L's regulatory assets and liabilities are detailed in the following table.

	September 30 2011		December 31 2010
Regulatory Assets	(millions)		
Taxes recoverable through future rates	$ 222.3		$ 222.3
Asset retirement obligations	30.4		27.5
Pension and post-retirement costs	373.2	(a)	386.1
Deferred customer programs	48.2	(b)	44.7
Rate case expenses	9.9	(c)	12.3
Skill set realignment costs	3.7	(d)	4.8
Fuel adjustment clauses	30.1	(c)	8.4
Acquisition transition costs	26.2	(e)	29.3
Iatan No. 1 and Common facilities depreciation and carrying costs	16.5		15.1
Iatan No. 2 construction accounting costs	27.6		17.2
Other	2.2	(f)	3.4
Total	$ 790.3		$ 771.1
Regulatory Liabilities			
Taxes refundable through future rates	$ 103.3		$ 105.1
Emission allowances	$ 83.0		$ 85.9
Asset retirement obligations	40.9		44.9
Pension	0.5		-
Other	11.2		10.5
Total	$ 238.9		$ 246.4

(a) Represents the funded status of the pension plans more than offset by related liabilities. Also includes pension settlements amortized over various periods and financial and regulatory accounting method differences not included in rate base that will be eliminated over the life of the pension plans.
(b) $11.3 million not included in rate base and amortized over various periods.
(c) Not included in rate base and amortized over various periods.
(d) $2.5 million not included in rate base and amortized through 2017.
(e) Not included in rate base and amortized through 2016.
(f) Certain insignificant items are not included in rate base and amortized over various periods.

6. PENSION PLANS, OTHER EMPLOYEE BENEFITS AND VOLUNTARY SEPARATION PROGRAM

KCP&L does not have a defined pension plan; however, KCP&L employees and officers participate in Great Plains Energy's pension plans. Great Plains Energy maintains defined benefit pension plans for substantially all active and inactive employees, including officers, and also provides certain post-retirement health care and life insurance benefits for substantially all retired employees of KCP&L, GMO, and Wolf Creek Nuclear Operating Corporation (WCNOC).

KCP&L records pension expense in accordance with rate orders from the MPSC and KCC that allow the difference between pension costs under Generally Accepted Accounting Principles (GAAP) and pension costs for ratemaking to be recognized as a regulatory asset or liability. The current rate orders allow similar regulatory treatment for post-retirement benefits. The differences between the financial and regulatory accounting methods are due to timing and will be eliminated over the life of the pension and post-retirement plans.

The following tables provide Great Plains Energy's components of net periodic benefit costs prior to the effects of capitalization and sharing with joint-owners of power plants.

Three Months Ended September 30	Pension Benefits 2011	Pension Benefits 2010	Other Benefits 2011	Other Benefits 2010
Components of net periodic benefit costs	(millions)			
Service cost	$ 7.8	$ 7.6	$ 0.7	$ 1.0
Interest cost	12.4	12.3	2.0	2.2
Expected return on plan assets	(9.5)	(9.2)	(0.4)	(0.5)
Prior service cost	1.1	1.1	1.8	1.8
Recognized net actuarial loss (gain)	9.7	9.4	(0.1)	(0.1)
Transition obligation	-	-	0.3	0.3
Settlement charge	10.0	-	-	-
Net periodic benefit costs before regulatory adjustment	31.5	21.2	4.3	4.7
Regulatory adjustment	(12.8)	(8.1)	0.4	-
Net periodic benefit costs	$ 18.7	$ 13.1	$ 4.7	$ 4.7

Year to Date September 30	Pension Benefits 2011	Pension Benefits 2010	Other Benefits 2011	Other Benefits 2010
Components of net periodic benefit costs	(millions)			
Service cost	$ 23.4	$ 22.8	$ 2.3	$ 2.8
Interest cost	37.5	36.9	5.9	6.6
Expected return on plan assets	(28.8)	(27.5)	(1.3)	(1.6)
Prior service cost	3.4	3.5	5.4	5.4
Recognized net actuarial loss (gain)	28.9	28.1	(0.4)	(0.1)
Transition obligation	-	-	1.0	1.0
Settlement charge	10.2	-	-	-
Net periodic benefit costs before regulatory adjustment	74.6	63.8	12.9	14.1
Regulatory adjustment	(25.1)	(24.6)	0.7	-
Net periodic benefit costs	$ 49.5	$ 39.2	$ 13.6	$ 14.1

Year to date September 30, 2011, Great Plains Energy contributed $42.0 million to the pension plans and expects to contribute an additional $80.2 million in 2011 to satisfy the funding requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA), and the MPSC and KCC rate orders, the majority of which is expected to be paid by KCP&L. Also in 2011, Great Plains Energy expects to contribute $17.1 million to the post-retirement benefit plans, of which the majority will be funded by KCP&L.

Voluntary Separation Program

In March 2011, Great Plains Energy and KCP&L announced an organizational realignment and voluntary separation program to assist in the management of overall costs within the level reflected in the Companies' retail electric rates and to enhance organizational efficiency. Savings from the realignment process and voluntary separation program, including approximately $15 million in labor costs on an annual basis, are expected to partially offset projected cost increases. Under the voluntary separation program, any non-union employee could voluntarily elect to separate and receive a severance payment equal to two weeks of salary for every year of employment, with a minimum severance payment equal to fourteen weeks of salary. There were 140 employees that made such elections and the majority separated on April 30, 2011. KCP&L recorded $9.2 million year to date September 30, 2011, related to this voluntary separation program.

Great Plains Energy recorded a $10.0 million pension settlement charge during the third quarter of 2011 from the voluntary separation program as a result of accelerated pension distributions. Substantially all of the charge was deferred as a regulatory asset and is expected to be recovered over future periods pursuant to regulatory agreements. The amount of accelerated pension distributions resulting from the voluntary separation program resulted in increased pension funding requirements in 2011 under ERISA.

7. EQUITY COMPENSATION

KCP&L does not have an equity compensation plan; however, certain KCP&L employees participate in Great Plains Energy's Long-Term Incentive Plan. Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by Great Plains Energy's shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, stock options, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L. Forfeiture rates are based on historical forfeitures and future expectations and are reevaluated annually.

The following table summarizes KCP&L's equity compensation expense and associated income tax benefits.

	Three Months Ended September 30		Year to Date September 30	
	2011	2010	2011	2010
	(millions)			
Compensation expense	$ 0.8	$ 0.6	$ 3.1	$ 2.4
Income tax benefits	0.2	0.2	1.2	0.4

Performance Shares

Performance share activity year to date September 30, 2011, is summarized in the following table.

	Performance Shares	Grant Date Fair Value*
Beginning balance	431,784	$ 18.01
Granted	140,128	26.15
Earned	(68,258)	11.04
Forfeited	(61,612)	22.38
Ending balance	442,042	21.06

* weighted-average

At September 30, 2011, the remaining weighted-average contractual term was 1.2 years. The weighted-average grant-date fair value of shares granted was $26.30 and $26.15 for the three months ended and year to date September 30, 2011, respectively. There were no shares granted for the three months ended September 30, 2010. The weighted-average grant-date fair value of shares granted year to date September 30, 2010, was $23.37. At September 30, 2011, there was $2.8 million of total unrecognized compensation expense, net of forfeiture rates, related to performance shares granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of performance shares earned and paid year to date September 30, 2011 and 2010, was $0.8 million and insignificant, respectively.

The fair value of performance share awards is estimated using a Monte Carlo simulation technique that uses the closing stock price at the valuation date and incorporates assumptions for inputs of expected volatilities, dividend yield and risk-free rates. Expected volatility is based on daily stock price change during a historical period commensurate with the remaining term of the performance period of the grant. The risk-free rate is based upon the rate at the time of the evaluation for zero-coupon government bonds with a maturity consistent with the remaining performance period of the grant. The dividend yield is based on the most recent dividends paid and the actual closing stock price on the valuation date. For shares granted in 2011, inputs for expected volatility, dividend yield and risk-free rates ranged from 28%-30%, 3.98%-4.35%, and 0.61%-1.15%, respectively.

Restricted Stock

Restricted stock activity year to date September 30, 2011, is summarized in the following table.

	Nonvested Restricted Stock	Grant Date Fair Value*
Beginning balance	406,657	$ 16.23
Granted and issued	182,385	19.03
Vested	(149,688)	17.29
Forfeited	(53,171)	17.25
Ending balance	386,183	17.06

* weighted-average

At September 30, 2011, the remaining weighted-average contractual term was 1.6 years. The weighted-average grant-date fair value of shares granted for the three months ended and year to date September 30, 2011, was $17.89 and $19.03, respectively. The weighted-average grant-date fair value of shares granted for the three months ended and year to date September 30, 2010, was $18.32 and $17.80, respectively. At September 30, 2011, there was $2.4 million of total unrecognized compensation expense, net of forfeiture rates, related to nonvested restricted stock granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. There were no shares vested for the three months ended September 30, 2011. The total fair value of shares vested year to date September 30, 2011, was $2.6 million. The total fair value of shares vested for the three months ended and year to date September 30, 2010, was $0.9 million and $7.3 million, respectively.

8. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

KCP&L's $600 million revolving credit facility with a group of banks to provide support for its issuance of commercial paper and other general corporate purposes expires in August 2013. Great Plains Energy and KCP&L may transfer up to $200 million of unused commitments between Great Plains Energy's and KCP&L's facilities. A default by KCP&L on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At September 30, 2011, KCP&L was in compliance with this covenant. At September 30, 2011, KCP&L had $10.5 million of commercial paper outstanding, at a weighted-average interest rate of 0.35%, $31.5 million of letters of credit outstanding and no outstanding cash borrowings under the facility. At December 31, 2010, KCP&L had $263.5 million of commercial paper outstanding, at a weighted-average interest rate of 0.41%, $24.4 million of letters of credit outstanding and no outstanding cash borrowings under the facility.

9. LONG-TERM DEBT

KCP&L's long-term debt is detailed in the following table.

	Year Due	September 30 2011	December 31 2010
		(millions)	
General Mortgage Bonds			
4.87% EIRR bonds [(a)(b)]	2012-2035	$ 119.3	$ 158.8
7.15% Series 2009A (8.59% rate)[(c)]	2019	400.0	400.0
4.65% EIRR Series 2005	2035	50.0	50.0
EIRR Series 2007A-1[(d)]	2035	-	63.3
EIRR Series 2007A-2[(d)]	2035	-	10.0
5.375% EIRR Series 2007B	2035	73.2	73.2
Senior Notes			
6.50% Series	2011	150.0	150.0
5.85% Series (5.72% rate)[(c)]	2017	250.0	250.0
6.375% Series (7.49% rate)[(c)]	2018	350.0	350.0
6.05% Series (5.78% rate)[(c)]	2035	250.0	250.0
5.30% Series	2041	400.0	-
EIRR bonds			
4.90% Series 2008	2038	23.4	23.4
Other	2012-2018	2.9	3.3
Unamortized discount		(4.3)	(2.0)
Total		$ 2,064.5	$ 1,780.0

(a) Weighted-average interest rates at September 30, 2011

(b) September 30, 2011, does not include $39.5 million EIRR Series 1993B bonds because the bonds have been repurchased and are held by KCP&L

(c) Rate after amortizing gains/losses recognized in OCI on settlements of interest rate hedging instruments

(d) September 30, 2011, does not include $63.3 million EIRR Series 2007 A-1and $10.0 million EIRR Series 2007 A-2 bonds because the bonds have been repurchased and are held by KCP&L

Fair Value of Long-Term Debt

Fair value of long-term debt is based on quoted market prices, with the incremental borrowing rate for similar debt used to determine fair value if quoted market prices were not available. At September 30, 2011, and December 31, 2010, the book value of KCP&L's long-term debt, including current maturities, was $2.1 billion and $1.8 billion, respectively. At September 30, 2011, and December 31, 2010, the fair value of KCP&L's long-term debt, including current maturities, was $2.3 billion and $1.9 billion, respectively.

KCP&L General Mortgage Bonds and EIRR Bonds

In April 2011, KCP&L purchased in lieu of redemption its $63.3 million EIRR Series 2007A-1, $10.0 million EIRR Series 2007A-2 and $39.5 million EIRR Series 1993B bonds. KCP&L opted to purchase rather than remarket the bonds given the poor conditions in the tax-exempt market. KCP&L issued commercial paper to fund the purchase of the bonds. As of September 30, 2011, the bonds were still outstanding, but were not reported as a liability on the balance sheet since they are being held by KCP&L. KCP&L has the ability to remarket these bonds to third parties whenever it determines market conditions are sufficiently attractive to do so.

KCP&L Senior Notes

In September 2011, KCP&L issued $400.0 million of 5.30% unsecured Senior Notes, maturing in 2041.

10. COMMITMENTS AND CONTINGENCIES

Environmental Matters

KCP&L is subject to extensive regulation by federal, state and local authorities with regard to environmental matters primarily through their utility operations. In addition to imposing extensive and continuing compliance obligations, laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is expected to be material to KCP&L. Failure to comply with environmental requirements or to timely recover environmental costs through rates could have a material adverse effect on KCP&L's results of operations, financial position and cash flows.

The following discussion groups environmental and certain associated matters into the broad categories of air and climate change, water, solid waste and remediation.

Air and Climate Change Overview

The Clean Air Act and associated regulations enacted by the Environmental Protection Agency (EPA) form a comprehensive program to preserve air quality. States are required to establish regulations and programs to address all requirements of the Clean Air Act and have the flexibility to enact more stringent requirements. All of KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Air Act.

KCP&L's current estimate of capital expenditures (exclusive of AFUDC and property taxes) to comply with the currently-effective Clean Air Interstate Rule (CAIR), the replacement to CAIR or the Cross-State Air Pollution Rule (CSAPR), the best available retrofit technology (BART) rule, the SO_2 national ambient air quality standard (NAAQS), the industrial boiler rule and proposed maximum achievable control technology (MACT) standards for mercury and other hazardous air pollutant emissions (all of which are discussed below) is approximately $1 billion. The actual cost of compliance with any existing, proposed or future rules may be significantly different from the cost estimate provided.

The approximate $1 billion current estimate of capital expenditures reflects the following capital projects:

- KCP&L's LaCygne No. 1 scrubber and baghouse installed by June 2015;
- KCP&L's LaCygne No. 2 full air quality control system (AQCS) installed by June 2015; and
- KCP&L's Montrose No. 3 full AQCS installed by approximately 2016.

In September 2011, KCP&L commenced construction of the LaCygne project. Other capital projects at KCP&L's Montrose Nos. 1 and 2 are possible but are currently considered less likely. Any capacity and energy requirements resulting from a decision not to proceed with these less likely projects is currently expected to be met through renewable energy additions required under Missouri and Kansas renewable energy standards, demand side management programs, construction of combustion turbines and/or combined cycle units, and/or power purchase agreements.

The estimate does not reflect the non-capital costs KCP&L incurs on an ongoing basis to comply with environmental laws, which may increase in the future due to KCP&L's ongoing compliance with current or future environmental laws. KCP&L expects to seek recovery of the costs associated with environmental requirements through rate increases; however, there can be no assurance that such rate increases would be granted. KCP&L may be subject to materially adverse rate treatment in response to competitive, economic, political, legislative or regulatory pressures and/or public perception of KCP&L's environmental reputation.

Clean Air Interstate Rule (CAIR) and Cross-State Air Pollution Rule (CSAPR)

The CAIR requires reductions in SO_2 and NO_x emissions in 28 states, including Missouri. The reductions in SO_2 and NO_x emissions are accomplished through statewide caps for NO_x and SO_2. KCP&L's fossil fuel-fired plants located in Missouri are subject to CAIR, while their fossil fuel-fired plants in Kansas are not.

On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR in its entirety and remanded the matter to the EPA to promulgate a new rule consistent with its opinion. On December 23, 2008, the Court issued an order remanding CAIR to the EPA to revise the rule consistent with its July 2008 order. The CAIR remains in effect through 2011.

CAIR currently establishes a market-based cap-and-trade program with an emission allowance allocation. Facilities demonstrate compliance with CAIR by holding sufficient allowances for each ton of SO_2 and NO_x emitted in any given year. KCP&L is currently allowed to utilize unused SO_2 emission allowances that they have either accumulated during previous years of the Acid Rain Program or purchased to meet the more stringent CAIR requirements. At September 30, 2011, KCP&L had accumulated unused SO_2 emission allowances sufficient to support over 150,000 tons of SO_2 emissions (enough to support expected requirements under the CAIR and the Acid Rain Program for the foreseeable future) under the provisions of the Acid Rain program, which are recorded in inventory at zero cost. KCP&L purchases NO_x allowances as needed.

In July 2011, the EPA finalized the CSAPR to replace the currently-effective CAIR. The CSAPR, like CAIR, will require the states within its scope to reduce power plant SO_2 and NO_x emissions that contribute to ozone and fine particle nonattainment in other states. The geographical scope of the CSAPR is broader than CAIR, and includes Kansas in addition to Missouri and other states. Kansas and Missouri are only included for fine particulate matter control in the final CSAPR, but the EPA concurrently proposed a supplemental notice of proposed rulemaking to include both states for ozone season control which the EPA intends to finalize in November 2011. The CSAPR would also impose more stringent emissions limitations than CAIR and, unlike CAIR, would not utilize Acid Rain Program allowances for compliance. In the CSAPR, the EPA set an emissions budget for each of the affected states. The CSAPR allows limited interstate emissions allowance trading among power plants; however, it does not permit trading of SO_2 allowances between KCP&L's Kansas and Missouri power plants. Compliance with the CSAPR begins in 2012. There would be additional reductions in SO_2 allowances allocable to KCP&L's Missouri power plants taking effect in 2014. There is no such 2014 additional reduction in SO_2 allowances allocable to KCP&L's Kansas power plants. In October 2011, the EPA proposed technical adjustments to the final CSAPR. The proposed rule amends the assurance penalty provisions to start in 2014, instead of 2012. The EPA proposed to revise certain unit-level allocations in six states, including Kansas, affected by federally enforceable consent agreements. This would allocate additional allowances to KCP&L's LaCygne Station to assist in compliance with CSAPR.

The finalized CSAPR is complex and KCP&L is evaluating its impacts. KCP&L projects that it may not be allocated sufficient SO_2 or NO_X emissions allowances to cover its currently expected operations starting in 2012. Any shortfall in allocated allowances is anticipated to be addressed through a combination of permissible allowance trading, installing additional emission control equipment, changes in plant processes, or purchasing additional power in the wholesale market. Multiple states, utilities and other parties, including KCP&L, have filed reconsideration requests and stays with the EPA and/or the D.C. Circuit Court.

Best Available Retrofit Technology (BART) Rule

The EPA BART rule directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below limits set by the state or whether retrofit measures are needed to reduce emissions. BART applies to specific eligible facilities including KCP&L's LaCygne Nos. 1 and 2 in Kansas, KCP&L's Iatan No. 1, and KCP&L's Montrose No. 3 in Missouri. Both Missouri and Kansas have submitted

BART plans to the EPA but neither Missouri nor Kansas has received EPA approval for their BART plans. In August 2011, the EPA proposed to approve the Kansas BART plan.

Mercury and Other Hazardous Air Pollutant Emissions
In January 2009, the EPA issued a memorandum stating that new electric steam generating units (EGUs) that began construction while the Clean Air Mercury Rule (CAMR) was effective are subject to a new source MACT determination on a case-by-case basis.

In July 2009, the EPA sent letters notifying KCP&L that MACT determinations and schedules of compliance are required for coal and oil-fired EGUs that began actual construction or reconstruction after December 15, 2000, and identified Iatan No. 2 and Hawthorn No. 5 as affected EGUs. This was an outcome of the D.C. Court of Appeals' vacatur of both the CAMR and the contemporaneously promulgated rule removing EGUs from MACT requirements. In May 2011, KCP&L received a letter from the Missouri Department of Natural Resources (MDNR) stating the MACT determination was not required for Hawthorn No. 5. It is not currently known how MACT determinations and schedules of compliance will impact the permitting or operating requirements for Iatan No. 2, but it is possible a MACT determination may ultimately require additional emission control equipment and permit limits.

In April 2010, the EPA, in a court approved settlement, agreed to develop MACT standards for mercury and potentially other hazardous air pollutant emissions. In the settlement agreement, the EPA agreed to propose MACT standards in March 2011 and is expected to issue final standards by December 2011. In March 2011, the EPA issued a proposed rule that would reduce emissions of hazardous air pollutants from new and existing coal-fired EGUs with a capacity of 25MW or greater. The proposed rule would establish numerical emission limits for mercury, particulate matter (a surrogate for non-mercury metals), and hydrogen chloride (a surrogate for acid gases). The proposed rule would establish work practices, instead of numerical emission limits, for organic hazardous air pollutants, including dioxin/furan. Compliance with the rule would need to be addressed by installing additional emission control equipment, changes in plant operation, purchasing additional power in the wholesale market or a combination of these and other alternatives. Any final rule could have a significant effect on KCP&L's results of operations, financial position and cash flows.

Industrial Boiler Rule
In February 2011, the EPA issued a final rule that would reduce emissions of hazardous air pollutants from new and existing industrial boilers. The final rule establishes numeric emission limits for mercury, dioxin, particulate matter (as a surrogate for non-mercury metals), hydrogen chloride (as a surrogate for acid gases), and carbon monoxide (as a surrogate for non-dioxin organic hazardous air pollutants). The final rule establishes emission limits for KCP&L's new and existing units that produce steam other than for the generation of electricity. The final rule does not apply to KCP&L's electricity generating boilers, but would apply to auxiliary boilers at other generating facilities. In May 2011, the EPA announced it would stay the effective date of the final rule during reconsideration. The EPA indicated it will propose a revised rule in November 2011 and issue another final rule by the end of April 2012.

New Source Review
The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to reduce emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in regulated emissions.

KCP&L has received requests for information from the Kansas Department of Health and Environment (KDHE) pertaining to a past LaCygne No. 1 scrubber project. KCP&L is working with the KDHE to resolve this issue and management currently believes the outcome will not have a significant impact on KCP&L's results of operations, financial position and cash flows.

Collaboration Agreement
In March 2007, KCP&L, the Sierra Club and the Concerned Citizens of Platte County entered into a Collaboration Agreement under which KCP&L agreed to pursue a set of initiatives including energy efficiency, additional wind generation, lower emission permit levels at its Iatan and LaCygne generating stations and other initiatives designed to offset CO_2 emissions. Full implementation of the terms of the Collaboration Agreement will necessitate approval from the appropriate authorities, as some of the initiatives in the agreement require regulatory approval.

In 2006, KCP&L installed 100MW of wind generation at its Spearville wind site. KCP&L agreed in the Collaboration Agreement to pursue increasing its wind generation capacity to 500MW in total by the end of 2012 with 100MW to be added by the end of 2010 and the remainder added by the end of 2012, subject to regulatory approval. In 2010, KCP&L completed a 48MW wind project adjacent to its existing Spearville wind site with wind turbines it already owned and also secured 52MW of renewable energy credits. During 2011, KCP&L entered into a 20-year power purchase agreement for approximately 131MW of wind generation beginning in 2012.

KCP&L has a consent agreement with the KDHE incorporating limits for stack particulate matter emissions, as well as limits for NO_x and SO_2 emissions, at its LaCygne Station that, consistent with the Collaboration Agreement, will be below the presumptive limits under BART. KCP&L further agreed to use its best efforts to install emission control technologies to reduce those emissions from the LaCygne Station prior to the required compliance date under BART, but in no event later than June 1, 2015. In February 2011, KCP&L filed a request with KCC for predetermination of the ratemaking treatment that would apply to the recovery of costs for its 50% share of the environmental equipment required to comply with BART at the LaCygne Station. The request for predetermination included an estimated total project cost of $1.23 billion (excluding AFUDC and property tax). KCP&L's 50% share of the estimated cost is $615 million. In August 2011, KCC issued its order on the predetermination request. In the order, KCC stated that KCP&L's decision to retrofit LaCygne was reasonable, reliable, efficient and prudent and the $1.23 billion cost estimate is reasonable. If the cost for the project is at or below the $1.23 billion estimate, absent a showing of fraud or other intentional imprudence, KCC stated that it will not re-evaluate the prudency of the cost of the project. If the cost of the project exceeds the $1.23 billion estimate and KCP&L seeks to recover amounts exceeding the estimate, KCP&L will bear the burden of proving that any additional costs were prudently incurred. KCP&L began the project in September 2011.

In a related proceeding, in January 2011, KCC opened a general investigation docket regarding KCP&L and Westar environmental retrofits upon the recommendation of the KCC Staff and the Citizens Utility Ratepayers Board. KCP&L cannot predict the outcome or timing of this matter but the outcome could have the potential to impact KCP&L's resource planning in the future.

In the Collaboration Agreement, KCP&L also agreed to offset an additional 711,000 tons of CO_2 by the end of 2012. KCP&L currently expects to achieve this offset through a number of alternatives, including improving the efficiency of its coal-fired units, equipping certain gas-fired units for winter operation and, if necessary, possibly reducing output of, or retiring, one or more coal-fired units.

Climate Change
KCP&L is subject to existing greenhouse gas reporting regulations and, as discussed below, is subject to certain greenhouse gas permitting requirements starting in 2011. Management believes it is possible that additional

federal or relevant state or local laws or regulations could be enacted to address global climate change. At the international level, while the United States is not a current party to the Kyoto Protocol, it has agreed to undertake certain voluntary actions under the non-binding Copenhagen Accord and pursuant to subsequent international discussions relating to climate change, including the establishment of a goal to reduce greenhouse gas emissions. International agreements legally binding on the United States may be reached in the future. Such new laws or regulations could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as CO_2, which are created in the combustion of fossil fuels. KCP&L's current generation capacity is primarily coal-fired and is estimated to produce about one ton of CO_2 per MWh, or approximately 17 million tons per year.

Laws have recently been passed in Missouri and Kansas, the states in which KCP&L's retail electric businesses are operated, setting renewable energy standards, and management believes that national clean or renewable energy standards are also possible. While management believes additional requirements addressing these matters will probably be enacted, the timing, provisions and impact of such requirements, including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time. In addition, certain federal courts have held that state and local governments and private parties have standing to bring climate change tort suits seeking company-specific emission reductions and monetary or other damages. While KCP&L is not a party to any climate change tort suit, there is no assurance that such suits may not be filed in the future or as to the outcome if such suits are filed. Such requirements or litigation outcomes could have the potential for a significant financial and operational impact on KCP&L. KCP&L would likely seek recovery of capital costs and expenses for compliance through rate increases; however, there can be no assurance that such rate increases would be granted.

Legislation concerning the reduction of emissions of greenhouse gases, including CO_2, is being considered at the federal and state levels. The timing and effects of any such legislation cannot be determined at this time. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In May 2010, the EPA issued a final rule addressing greenhouse gas emissions from stationary sources under the Clean Air Act permitting programs. This final rule sets thresholds for greenhouse gas emissions that define when permits under the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required for new and existing industrial facilities. The EPA phased in the Clean Air Act permitting requirements for greenhouse gas emissions in two initial steps. In step 1, which started January 2, 2011, only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than greenhouse gas) are subject to Title V or PSD permitting requirements, respectively, for their greenhouse gas emissions. For these projects, only projects with new or increases of greenhouse gas emissions of 75,000 tons per year or more of total greenhouse gases, on a CO_2 equivalent basis, need to determine the best available control technology for their greenhouse gas emissions. In addition, sources subject to the Title V Operating Permit Program need to address greenhouse gas emissions as those permits are applied for or renewed. In step 2, which started July 1, 2011, Title V and PSD permitting requirements now cover, for the first time, new construction projects that emit greenhouse gas emissions of at least 100,000 tons per year even if they do not exceed the permitting thresholds for any other pollutant. In addition, modifications at such existing facilities that increase greenhouse gas emissions by at least 75,000 tons per year are subject to permitting requirements, even if they do not significantly increase emissions of any other pollutant. KCP&L's generating facilities that trigger these thresholds for new installations, modifications or Title V operating permits are subject to this rule.

In March 2011, the EPA announced it finalized a settlement agreement to issue a rule that will address greenhouse gas emissions from EGUs. The rule would establish new source performance standards for new and modified EGUs and emission guidelines for existing EGUs. The EPA expects to issue proposed regulations in early 2012 and final regulations by May 2012.

At the state level, a Kansas law enacted in May 2009 requires Kansas public electric utilities, including KCP&L, to have renewable energy generation capacity equal to at least 10% of their three-year average Kansas peak retail demand by 2011. The percentage increases to 15% by 2016 and 20% by 2020. A Missouri law enacted in November 2008 requires at least 2% of the electricity provided by Missouri investor-owned utilities (including KCP&L) to their Missouri retail customers to come from renewable resources, including wind, solar, biomass and hydropower, by 2011, increasing to 5% in 2014, 10% in 2018, and 15% in 2021, with a small portion (estimated to be about 2MW in 2011 for KCP&L) required to come from solar resources.

KCP&L projects that its existing renewable resources (including accumulated renewable energy credits) will be sufficient for compliance with the Missouri requirements, exclusive of the solar requirement, through 2021. KCP&L projects that the purchase of solar renewable energy credits will be sufficient for compliance with the Missouri solar requirements for the foreseeable future.

KCP&L also projects that its existing renewable resources (including both accumulated renewable energy credits and purchased renewable energy credits) will be sufficient for compliance with the 2011 Kansas requirements. During 2011, KCP&L entered into a 20-year power purchase agreement for approximately 131MW of wind generation beginning in 2012. With the addition of this power purchase agreement along with its existing renewable resources, KCP&L anticipates its renewable resources will be sufficient for compliance with the Kansas requirements through 2012.

Additionally, in November 2007, governors from six Midwestern states, including Kansas, signed the Midwestern Greenhouse Gas Reduction Accord, which has established the goal of reducing member states' greenhouse gas emissions to 15% to 20% below 2005 levels by 2020, and 60% to 80% below 2005 levels by 2050.

Greenhouse gas legislation or regulation has the potential of having significant financial and operational impacts on KCP&L, including the potential costs and impacts of achieving compliance with limits that may be established. However, the ultimate financial and operational consequences to KCP&L cannot be determined until such legislation is passed and/or regulations are issued. Management will continue to monitor the progress of relevant legislation and regulations.

Ozone NAAQS

In June 2007, monitor data indicated that the Kansas City area violated the 1997 primary eight-hour ozone NAAQS. Missouri and Kansas have implemented the responses established in the maintenance plans for control of ozone. The responses in both states do not require additional controls at KCP&L's generation facilities beyond the currently proposed controls for CSAPR and BART. The EPA has various options over and above the implementation of the maintenance plans for control of ozone to address the violation but has not yet acted. At this time, management is unable to predict how the EPA will respond or how that response will impact KCP&L's operations. However, the EPA's response could have a significant effect on KCP&L's results of operations, financial position and cash flows.

In March 2008, the EPA significantly strengthened its NAAQS for ground-level ozone. The EPA revised the primary eight-hour ozone standard, designed to protect public health, to a level of 0.075 parts per million (ppm). The EPA also strengthened the secondary eight-hour ozone standard to the level of 0.075 ppm making it identical to the revised primary standard. The previous primary and secondary standards, set in 1997, were effectively 0.084 ppm.

In March 2009, the MDNR and KDHE submitted to the EPA their determinations that the Kansas City area is a nonattainment area under the 2008 primary eight-hour ozone standard. The EPA will make final designations of attainment and nonattainment areas. By 2013, states must submit state implementation plans outlining how states will reduce ozone to meet the standards in nonattainment areas. Although the impact on KCP&L's operations will not be known until after the final nonattainment designations and the state implementation plans are submitted, it could have a significant effect on KCP&L's results of operations, financial position and cash flows.

In January 2010, the EPA proposed to reconsider and further strengthen the 2008 NAAQS for ground-level ozone. The EPA proposed to strengthen the primary eight-hour ozone standard to a level within the range of 0.060-0.070 ppm. The EPA also proposed to establish a distinct cumulative, seasonal secondary standard, designed to protect sensitive vegetation and ecosystems, to within the range of 7-15 ppm-hours. In September 2011, President Obama requested that the EPA withdraw the proposed rule reconsidering the 2008 NAAQS and the EPA announced it will proceed with implementation of the 2008 primary eight-hour ozone standard of 0.075 ppm. The EPA indicated, based on the available ozone air quality data, that the Kansas City area would meet the standard.

SO_2 NAAQS

In June 2010, the EPA strengthened the primary NAAQS for SO_2. The EPA revised the primary SO_2 standard by establishing a new 1-hour standard at a level of 0.075 ppm. The EPA revoked the two existing primary standards of 0.140 ppm evaluated over 24 hours and 0.030 ppm evaluated over an entire year. In July 2011, the MDNR recommended to the EPA that part of Jackson County, Missouri, which is in KCP&L's service territory, be designated a nonattainment area for the new 1-hour SO_2 standard. Although the impact on KCP&L's operations will not be known until after the nonattainment designations are approved and the state implementation plans are submitted, it could have a significant effect on KCP&L's results of operations, financial position and cash flows.

Montrose Station Notice of Violation

In June 2009, KCP&L received notification from the MDNR alleging that its Montrose Station had excess particulate matter emissions in 2008. KCP&L is working with the MDNR to resolve this issue and management believes the outcome will not have a significant impact on KCP&L's results of operations, financial position and cash flows.

Water

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to preserve water quality. Like the Clean Air Act, states are required to establish regulations and programs to address all requirements of the Clean Water Act, and have the flexibility to enact more stringent requirements. All of KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In March 2011, the EPA proposed regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures pursuant to a court approved settlement. KCP&L generation facilities with cooling water intake structures would be subject to a limit on how many fish can be killed by being pinned against intake screens (impingement) and would be required to conduct studies to determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms drawn into cooling water systems (entrainment). The EPA agreed to finalize the rule by July 2012. Although the impact on KCP&L's operations will not be known until after the rule is finalized, it could have a significant effect on KCP&L's results of operations, financial position and cash flows.

KCP&L holds a permit from the MDNR covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri river for cooling purposes and return the heated water to the Missouri river. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require KCP&L to reduce its generation at Hawthorn Station, install cooling towers or both, any of which could have a significant impact on KCP&L. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan Station.

Additionally, in September 2009, the EPA announced plans to revise the existing standards for water discharges from coal-fired power plants. In November 2010, the EPA filed a motion requesting court approval of a consent agreement in which the EPA agreed to propose a rule in July 2012 and to finalize it in January 2014. Until a rule is proposed and finalized, the financial and operational impacts to KCP&L cannot be determined.

Solid Waste
Solid and hazardous waste generation, storage, transportation, treatment and disposal is regulated at the federal and state levels under various laws and regulations. In May 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA) to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The EPA is considering two options in this proposal. Under the first option, the EPA would regulate CCRs as special wastes subject to regulation under subtitle C of RCRA (hazardous), when they are destined for disposal in landfills or surface impoundments. Under the second option, the EPA would regulate disposal of CCRs under subtitle D of RCRA (non-hazardous). The Companies principally use coal in generating electricity and dispose of the CCRs in both on-site facilities and facilities owned by third parties. The proposed CCR rule has the potential of having a significant financial and operational impact on KCP&L in connection with achieving compliance with the proposed requirements. However, the financial and operational consequences to KCP&L cannot be determined until an option is selected by the EPA and the final regulation is enacted.

Remediation
Certain federal and state laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) hold current and previous owners or operators of real property, and any person who arranges for the disposal or treatment of hazardous substances at a property, liable on a joint and several basis for the costs of cleaning up contamination at or migrating from such real property, even if they did not know of and were not responsible for such contamination. CERCLA and other laws also authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment.

At September 30, 2011, and December 31, 2010, KCP&L had $0.3 million accrued for environmental remediation expenses, which covers ground water monitoring at a former MGP site. The amount accrued was established on an undiscounted basis and KCP&L does not currently have an estimated time frame over which the accrued amounts may be paid.

In January 2010, the EPA announced an advance notice of proposed rulemaking under CERCLA identifying classes of facilities for which the EPA will develop financial assurance requirements, including the electric power generation, transmission and distribution industry. The CERCLA financial assurance would be for risks associated with KCP&L's production, transportation, treatment, storage or disposal of CERCLA hazardous substances. The impact on KCP&L

cannot be determined until the regulations are finalized.

In April 2010, the EPA announced an advance notice of proposed rulemaking for the use and distribution in commerce of certain PCBs, PCB items and certain other areas of the PCB regulations. The EPA is reassessing the use, distribution in commerce, marking, and storage for reuse of liquid PCBs in electric and non-electric equipment and the use of the 50 ppm level for excluded PCB products among other things. The impact on KCP&L cannot be determined until the regulations are finalized.

Contractual Commitments
At September 30, 2011, KCP&L's contractual commitments for environmental retrofits at its LaCygne station are $123.3 million, $385.7 million, $286.6 million, $130.1 million and $6.3 million for the years 2011 though 2015, respectively. KCP&L owns 50% of the LaCygne station. KCP&L expects to be reimbursed by the other owner for its 50% share of the costs. KCP&L's other contractual commitments have not significantly changed at September 30, 2011, compared to December 31, 2010.

11. LEGAL PROCEEDINGS

KCP&L Spent Nuclear Fuel and Radioactive Waste
In January 2004, KCP&L and the other two Wolf Creek owners filed a lawsuit against the United States in the U.S. Court of Federal Claims seeking $14.1 million of damages resulting from the government's failure to begin accepting spent nuclear fuel for disposal in January 1998, as the government was required to do by the Nuclear Waste Policy Act of 1982. The Wolf Creek case was tried before a U.S. Court of Federal Claims judge in June 2010, and a decision was issued in November 2010, granting KCP&L and the other two Wolf Creek owners $10.6 million ($5.0 million KCP&L share) in damages. In January 2011, KCP&L and the other two Wolf Creek owners as well as the United States filed appeals of the decision to the U.S. Court of Appeals for the Federal Circuit. The court has set a briefing schedule. Briefing likely will conclude in the fourth quarter of 2011, and the parties will present their oral arguments to the court sometime thereafter.

Iatan Levee Litigation
On May 22, 2009, several farmers filed suit against Great Plains Energy and KCP&L in the Circuit Court of Platte County, Missouri, alleging negligence, private nuisance, trespass and violations of the Missouri Crop Protection Act and seeking unspecified compensatory and punitive damages. These allegations stem from flooding at or near the Iatan Station in 2007 and 2008. The farmers allege the flooding was a result of maintenance of a nearby levee. Written discovery and depositions are underway and this matter is set for trial in May 2012. Management cannot predict the outcome of this matter.

12. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

KCP&L employees manage GMO's business and operate its facilities at cost. These costs totaled $25.0 million and $82.2 million, respectively, for the three months ended and year to date September 30, 2011, respectively. These costs totaled $26.3 million and $73.5 million, respectively, for the same periods in 2010. Additionally, KCP&L and GMO engage in wholesale electricity transactions with each other. KCP&L is also authorized to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L. The following table summarizes KCP&L's related party receivables and payables.

	September 30 2011	December 31 2010
	(millions)	
Net receivable from GMO	$ 45.7	$ 29.6
Receivable from Receivables Company	78.5	49.6
Net receivable from Great Plains Energy	14.0	13.3
Receivable from MPS Merchant	8.6	0.3

13. DERIVATIVE INSTRUMENTS

KCP&L is exposed to a variety of market risks including interest rates and commodity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on KCP&L's operating results. Commodity risk management activities, including the use of certain derivative instruments, are subject to the management, direction and control of an internal risk management committee. Management's interest rate risk management strategy uses derivative instruments to adjust KCP&L's liability portfolio to optimize the mix of fixed and floating rate debt within an established range. In addition, KCP&L uses derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances. Management maintains commodity price risk management strategies that use derivative instruments to reduce the effects of fluctuations in fuel expense caused by commodity price volatility. Counterparties to commodity derivatives and interest rate swap agreements expose KCP&L to credit loss in the event of nonperformance. This credit loss is limited to the cost of replacing these contracts at current market rates. Derivative instruments, excluding those instruments that qualify for the normal purchase normal sale election, which are accounted for by accrual accounting, are recorded on the balance sheet at fair value as an asset or liability. Changes in the fair value of derivative instruments are recognized currently in net income unless specific hedge accounting criteria are met.

KCP&L has posted collateral, in the ordinary course of business, for the aggregate fair value of all derivative instruments with credit risk-related contingent features that are in a liability position. At September 30, 2011, KCP&L has posted collateral in excess of the aggregate fair value of their derivative instruments; therefore, if the credit risk-related contingent features underlying these agreements were triggered, KCP&L would not be required to post additional collateral to its counterparties.

The Dodd-Frank Wall Street Reform and Consumer Protection Act includes provisions related to the swaps and over-the-counter derivative markets. The Companies currently expect that their commodity and interest rate hedges will be exempt from mandatory clearing and exchange trading requirements. Capital and margin requirements for these hedges are expected to be determined over the next year as regulatory agencies implement rules. While KCP&L currently does not anticipate this law and the associated regulatory rules will have a material impact on their financial condition, the ultimate impact cannot be reasonably determined until the final rules are issued.

Commodity Risk Management

KCP&L's risk management policy is to use derivative instruments to mitigate its exposure to market price fluctuations on a portion of its projected natural gas purchases to meet generation requirements for retail and firm wholesale sales. At September 30, 2011, KCP&L had fully hedged 2012 and had hedged 91% of 2013 projected natural gas usage for retail load and firm MWh sales, primarily by utilizing futures contracts and financial instruments. KCP&L has designated the natural gas hedges as cash flow hedges. The fair values of these instruments are recorded as derivative assets or liabilities with an offsetting entry to OCI for the effective portion of the hedge. To the extent the hedges are not effective, any ineffective portion of the change in fair market value would be recorded currently in fuel expense. KCP&L has not recorded any ineffectiveness on natural gas hedges for the three months ended and year to date September 30, 2011 and 2010.

The notional and recorded fair values of open positions for derivative instruments are summarized in the following table. The fair values of these derivatives are recorded on the consolidated balance sheets. The fair values below are gross values before netting agreements and netting of cash collateral.

	September 30 2011		December 31 2010	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
	(millions)			
Futures contracts				
Cash flow hedges	$ 2.6	$ (0.2)	$ 4.0	$ -

The fair values of KCP&L's open derivative positions are summarized in the following tables. The fair values below are gross values before netting agreements and netting of cash collateral.

September 30, 2011	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
Derivatives Designated as Hedging Instruments		(millions)	
Commodity contracts	Derivative instruments	$ -	$ 0.2
December 31, 2010			
Derivatives Designated as Hedging Instruments			
Commodity contracts	Derivative instruments	$ 0.1	$ 0.1

The following tables summarize the amount of gain (loss) recognized in OCI or earnings for interest rate and commodity hedges.

Derivatives in Cash Flow Hedging Relationship	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion): Income Statement Classification	Amount
Three Months Ended September 30, 2011	(millions)		(millions)
Interest rate contracts	$ -	Interest charges	$ (2.1)
Commodity contracts	(0.1)	Fuel	(0.1)
Income tax benefit (expense)	0.1	Income tax benefit (expense)	0.9
Total	$ -	Total	$ (1.3)
Year to Date September 30, 2011			
Interest rate contracts	$ -	Interest charges	$ (6.5)
Commodity contracts	(0.2)	Fuel	(0.1)
Income tax benefit (expense)	0.1	Income tax benefit (expense)	2.6
Total	$ (0.1)	Total	$ (4.0)
Three Months Ended September 30, 2010			
Interest rate contracts	$ -	Interest charges	$ (2.2)
Commodity contracts	(0.4)	Fuel	(0.5)
Income tax benefit (expense)	0.2	Income tax benefit (expense)	1.1
Total	$ (0.2)	Total	$ (1.6)
Year to Date September 30, 2010			
Interest rate contracts	$ -	Interest charges	$ (6.6)
Commodity contracts	(1.0)	Fuel	(0.5)
Income tax benefit (expense)	0.4	Income tax benefit (expense)	2.8
Total	$ (0.6)	Total	$ (4.3)

The amounts recorded in accumulated OCI related to the cash flow hedges are summarized in the following table.

	KCP&L September 30 2011	KCP&L December 31 2010
	(millions)	
Current assets	$ 11.5	$ 12.0
Current liabilities	(64.7)	(71.6)
Deferred income taxes	20.7	23.2
Total	$ (32.5)	$ (36.4)

KCP&L's accumulated OCI includes $8.9 million that is expected to be reclassified to expense over the next twelve months.

14. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad categories, giving the highest priority to quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. A definition of the various levels, as well as discussion of the various measurements within the levels, is as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets that KCP&L has access to at the measurement date. Assets categorized within this level consist of KCP&L's various exchange traded derivative instruments and equity and U.S. Treasury securities that are actively traded within KCP&L's decommissioning trust fund.

Level 2 – Market-based inputs for assets or liabilities that are observable (either directly or indirectly) or inputs that are not observable but are corroborated by market data. Assets and liabilities categorized within this level consist of KCP&L's various non-exchange traded derivative instruments traded in over-the-counter markets and certain debt securities within KCP&L's decommissioning trust fund.

Level 3 – Unobservable inputs, reflecting KCP&L's own assumptions about the assumptions market participants would use in pricing the asset or liability.

The following tables include KCP&L's balances of financial assets and liabilities measured at fair value on a recurring basis at September 30, 2011, and December 31, 2010.

			Fair Value Measurements Using		
Description	**September 30 2011**	**Netting[c]**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
			(millions)		
Assets					
Derivative instruments [a]	$ -	$ -	$ -	$ -	$ -
Nuclear decommissioning trust [b]					
Equity securities	75.2	-	75.2	-	-
Debt securities					
U.S. Treasury	14.7	-	14.7	-	-
U.S. Agency	3.6	-	-	3.6	-
State and local obligations	2.6	-	-	2.6	-
Corporate bonds	25.3	-	-	25.3	-
Foreign governments	0.7	-	-	0.7	-
Other	0.3	-	-	0.3	-
Total nuclear decommissioning trust	122.4	-	89.9	32.5	-
Total	122.4	-	89.9	32.5	-
Liabilities					
Derivative instruments [a]	-	(0.2)	0.2	-	-
Total	$ -	$ (0.2)	$ 0.2	$ -	$ -

Description	December 31 2010	Netting[(c)]	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(millions)		
Assets					
Derivative instruments [(a)]	$ -	$ (0.1)	$ 0.1	$ -	$ -
Nuclear decommissioning trust [(b)]					
Equity securities	85.5	-	85.5	-	-
Debt securities					
U.S. Treasury	8.9	-	8.9	-	-
U.S. Agency	4.8	-	-	4.8	-
State and local obligations	2.5	-	-	2.5	-
Corporate bonds	23.7	-	-	23.7	-
Foreign governments	0.7	-	-	0.7	-
Other	0.4	-	-	0.4	-
Total nuclear decommissioning trust	126.5	-	94.4	32.1	-
Total	126.5	(0.1)	94.5	32.1	-
Liabilities					
Derivative instruments [(a)]	-	(0.1)	0.1	-	-
Total	$ -	$ (0.1)	$ 0.1	$ -	$ -

(a) The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlations among fuel prices, net of estimated credit risk.

(b) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models. The total does not include $3.1 million and $2.7 million at September 30, 2011, and December 31, 2010, respectively, of cash and cash equivalents, which are not subject to the fair value requirements.

(c) Represents the difference between derivative contracts in an asset or liability position presented on a net basis by counterparty on the consolidated balance sheet where a master netting agreement exists between the Company and the counterparty.

The following table reconciles the beginning and ending balances for all level 3 assets and liabilities, net measured at fair value on a recurring basis for the year to date September 30, 2010.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	State & Local Obligations
	(millions)
Balance January 1, 2010	$ 0.2
Sales	(0.2)
Balance September 30, 2010	$ -

15. TAXES

Components of income tax expense is detailed in the following table.

	Three Months Ended September 30		Year to Date September 30	
	2011	2010	2011	2010
Current income taxes	(millions)			
Federal	$ (10.8)	$ (16.1)	$ (9.2)	$ 20.5
State	(0.9)	(2.7)	(0.7)	4.3
Total	(11.7)	(18.8)	(9.9)	24.8
Deferred income taxes				
Federal	53.8	64.0	73.7	54.3
State	9.3	11.8	13.8	9.6
Total	63.1	75.8	87.5	63.9
Noncurrent income taxes				
Federal	1.5	(2.4)	(9.1)	(1.5)
State	0.2	(0.3)	(0.9)	(0.1)
Total	1.7	(2.7)	(10.0)	(1.6)
Investment tax credit				
Deferral	-	-	-	(4.1)
Amortization	(0.5)	(0.5)	(1.0)	(1.2)
Total	(0.5)	(0.5)	(1.0)	(5.3)
Income tax expense	$ 52.6	$ 53.8	$ 66.6	$ 81.8

Income Tax Expense and Effective Income Tax Rates

Income tax expense and the effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

	Income Tax Expense		Income Tax Rate	
Three Months Ended September 30	2011	2010	2011	2010
	(millions)			
Federal statutory income tax	$ 48.2	$ 50.7	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	1.7	(1.1)	1.3	(0.8)
Amortization of investment tax credits	(0.5)	(0.5)	(0.4)	(0.4)
Federal income tax credits	(2.9)	(1.9)	(2.1)	(1.3)
State income taxes	5.7	5.6	4.1	3.9
Changes in uncertain tax positions	-	0.1	-	0.1
Other	0.4	0.9	0.3	0.6
Total	$ 52.6	$ 53.8	38.2 %	37.1 %

	Income Tax Expense		Income Tax Rate	
Year to Date September 30	**2011**	**2010**	**2011**	**2010**
	(millions)			
Federal statutory income tax	$ 65.6	$ 83.5	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	3.3	(5.2)	1.8	(2.2)
Amortization of investment tax credits	(1.0)	(1.2)	(0.5)	(0.5)
Federal income tax credits	(9.6)	(6.0)	(5.1)	(2.5)
State income taxes	7.6	8.6	4.0	3.6
Medicare Part D subsidy legislation	-	2.8	-	1.2
Changes in uncertain tax positions	0.4	0.1	0.2	0.1
Other	0.3	(0.8)	0.1	(0.5)
Total	$ 66.6	$ 81.8	35.5 %	34.2 %

Uncertain Tax Positions

At September 30, 2011, and December 31, 2010, KCP&L had $9.0 million and $19.1 million, respectively, of liabilities related to unrecognized tax benefits. Of these amounts, $0.3 million at September 30, 2011, and December 31, 2010, is expected to impact the effective tax rate if recognized. The $10.1 million decrease in unrecognized tax benefits is primarily due to a decrease of $12.1 million related to the settlement of the IRS audit for Great Plains Energy's 2006-2008 tax years. The tax benefit recognized related to the 2006-2008 IRS audit was mostly offset by an increase in deferred income tax liabilities, which resulted in an insignificant impact to net income.

The following table reflects activity for KCP&L related to the liability for unrecognized tax benefits.

	September 30 2011	December 31 2010
	(millions)	
Beginning balance	$ 19.1	$ 20.9
Additions for current year tax positions	-	1.3
Additions for prior year tax positions	2.3	1.5
Reductions for prior year tax positions	(12.4)	(1.6)
Settlements	-	(2.9)
Statute expirations	-	(0.1)
Ending balance	$ 9.0	$ 19.1

KCP&L recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. KCP&L had accrued interest related to unrecognized tax benefits of $0.3 million and $1.4 million at September 30, 2011, and December 31, 2010, respectively. Amounts accrued for penalties with respect to unrecognized tax benefits for KCP&L are insignificant.

KCP&L is unable to estimate the amount of unrecognized tax benefits that may be recognized in the next twelve months.

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				36,000,707
3	Preceding Quarter/Year to Date Changes in Fair Value				(36,000,707)
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				21,005,401
8	Current Quarter/Year to Date Changes in Fair Value				(21,005,401)
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (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	(41,726,231)	192,381	(41,533,850)		
2	4,001,320	327,363	40,329,390		
3		(584,066)	(36,584,773)		
4	4,001,320	(256,703)	3,744,617	159,989,390	163,734,007
5	(37,724,911)	(64,322)	(37,789,233)		
6	(36,391,138)	(10,804)	(36,401,942)		
7	4,001,320	58,020	25,064,741		
8		(147,908)	(21,153,309)		
9	4,001,320	(89,888)	3,911,432	122,811,031	126,722,463
10	(32,389,818)	(100,692)	(32,490,510)		

Schedule Page: 122(a)(b) Line No.: 7 Column: e

The recognition requirements of ASC 715 “Compensation-Retirement Benefits” results in recording unamortized transition costs, prior service costs and gain/losses for the pension and other post-retirement plans to accumulated other comprehensive income. In accordance with ASC 980 “Regulated Operations,” these costs were transferred to a regulatory asset.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

The recognition requirements of ASC 715 “Compensation-Retirement Benefits” results in recording unamortized transition costs, prior service costs and gain/losses for the pension and other post-retirement plans to accumulated other comprehensive income. In accordance with ASC 980 “Regulated Operations,” these costs were transferred to a regulatory asset.

Schedule Page: 122(a)(b) Line No.: 8 Column: g

Natural gas cash flow hedges for production fuel. As of September 30, 2011, KCP&L has fully hedged 2011 and 2012 projected natural gas usage for retail load and firm MWh sales and has hedged 91% of the 2013 projected natural gas usage for retail load and firm MWh sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,751,528,170	7,751,528,170
4	Property Under Capital Leases	2,064,187	2,064,187
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,753,592,357	7,753,592,357
9	Leased to Others		
10	Held for Future Use	8,985,368	8,985,368
11	Construction Work in Progress	181,916,554	181,916,554
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	7,944,494,279	7,944,494,279
14	Accum Prov for Depr, Amort, & Depl	3,210,662,284	3,210,662,284
15	Net Utility Plant (13 less 14)	4,733,831,995	4,733,831,995
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,070,313,964	3,070,313,964
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	140,348,320	140,348,320
22	Total In Service (18 thru 21)	3,210,662,284	3,210,662,284
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)	3,210,662,284	3,210,662,284

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
					3
					4
					5
					6
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					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

ELECTRIC PLANT IN SERVICE AND ACCUMULATED PROVISION FOR DEPRECIATION BY FUNCTION

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation and Amortization Balance at End of Quarter (c)
1	Intangible Plant	182,362,946	140,348,320
2	Steam Production Plant	3,025,982,052	1,235,708,864
3	Nuclear Production Plant	1,433,151,120	751,738,695
4	Hydraulic Production - Conventional		
5	Hydraulic Production - Pumped Storage		
6	Other Production	581,036,296	183,192,852
7	Transmission	410,136,302	178,790,297
8	Distribution	1,820,521,125	676,699,183
9	Regional Transmission and Market Operation		
10	General	298,338,329	64,361,312
11	TOTAL (Total of lines 1 through 10)	7,751,528,170	3,230,839,523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AG2-2010-AFS; Phase 5	849	561600		
3	AG1-2011-AFS; Phase 1	7,088	561600		
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	None				
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Missouri Case No. EU-2004-0294 and					
2	Kansas Case No. 04-WSEE-605-ACT:					
3	Non-nuclear asset retirement obligations recorded					
4	in accordance with ASC 410.	29,424,632	994,061			30,418,693
5						
6						
7	Deferred Regulatory Asset-Recoverable Taxes:					
8	Gross up of tax related items to be recovered					
9	from future rate payers.	223,035,409			746,420	222,288,989
10						
11						
12	Pension and OPEB costs deferred in accordance					
13	with Missouri Case No. ER-2010-0355 and Kansas					
14	Docket No. 10-KCPE-415-RTS.	364,440,509	23,633,014	926, 107	14,830,704	373,242,819
15						
16						
17	Missouri Case No. EO-2005-0329, ER-2007-0291,					
18	ER-2009-0089 and ER-2010-0355:					
19	Represents the deferred costs for the energy					
20	efficiency and affordability programs as provided					
21	in the Missouri Public Service Commission orders.					
22	Each vintage year will be amortized over 10 years.	34,209,533	3,366,951	908	868,157	36,708,327
23						
24						
25	Kansas Docket No. 04-KCPE-1025-GIE:					
26	Represents the deferred costs for the energy					
27	efficiency and affordability programs as provided					
28	in the Kansas Corporation Commission order.					
29	These costs will be recovered through an Energy					
30	Efficiency Rider to be filed by March 31 of each					
31	year to recover costs incurred during the previous					
32	calendar year. Costs are to be amortized over 1					
33	year starting each July.	11,394,644	2,431,829	908	2,768,135	11,058,338
34						
35						
36	Kansas Docket No. 10-KCPE-415-RTS:					
37	Deferred costs associated with the 2007 rate case					
38	preparation and presentation to the Kansas					
39	Corporation Commission with remaining balance to be					
40	amortized over 4 years beginning December 1, 2010.	186,069		928	13,615	172,454
41						
42						
43						
44	TOTAL	771,598,798	41,619,561		22,929,426	790,288,933

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Missouri Case No. ER-2009-0089 and					
2	Kansas Docket No. 10-KCPE-415-RTS:					
3	Deferred costs associated with the 2008 rate case					
4	preparation and presentation to the Missouri					
5	Public Service Commission and Kansas Corporation					
6	Commission to be amortized over 2 years for					
7	Missouri beginning September 1, 2009 and remaining					
8	balance amortized over 4 years for Kansas					
9	beginning December 1, 2010.	1,357,867		928	180,144	1,177,723
10						
11						
12	Missouri Case No. ER-2010-0355 and					
13	Kansas Docket No. 10-KCPE-415-RTS:					
14	Deferred costs associated with the 2010 rate case					
15	preparation and presentation to the Missouri					
16	Public Service Commission and Kansas Corporation					
17	Commission to be amortized over 3 years in Missouri					
18	beginning May 2011 and 4 years in Kansas beginning					
19	December 1, 2010.	9,179,921	26,194	928	678,014	8,528,101
20						
21						
22	Kansas Docket No. 06-KCPE-828-RTS:					
23	Deferred costs associated with the talent					
24	assessment to be amortized over 10 years					
25	beginning January 1, 2007.	119,224		923	5,419	113,805
26						
27						
28	Missouri Case No. ER-2006-0314:					
29	Represents the Missouri jurisdictional non-labor					
30	expenses charged to the strategic initiative					
31	projects. These costs are being amortized					
32	over 5 years beginning January 1, 2007.	199,916		923	99,958	99,958
33						
34						
35	Missouri Case No. ER-2009-0089:					
36	Missouri jurisdictional expenses incurred relating					
37	to the research and development tax credit					
38	studies. These costs will be amortized over					
39	5 years beginning September 2009.	249,678		923	19,712	229,966
40						
41						
42						
43						
44	TOTAL	771,598,798	41,619,561		22,929,426	790,288,933

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Kansas Docket No. 07-KCPE-905-RTS:					
2	Kansas jurisdictional Talent Assessment					
3	costs to be amortized over 10 years					
4	beginning January 1, 2008.	2,616,955		920	100,652	2,516,303
5						
6						
7	Kansas Docket No. 07-KCPE-905-RTS:					
8	Kansas jurisdictional Employment Augmentation					
9	Programs to be amortized over 10 years					
10	beginning January 1, 2008.	171,719		923	6,605	165,114
11						
12						
13	Missouri Case No. ER-2007-0291:					
14	Missouri jurisdictional Talent Assessment					
15	costs to be amortized over 5 years					
16	beginning January 1, 2008.	1,452,155		920	242,026	1,210,129
17						
18						
19	Kansas Docket No. 07-KCPE-905-RTS:					
20	Energy Cost Adjustment	18,935,055	11,167,118			30,102,173
21						
22						
23	Kansas Docket No. 10-KCPE-415-RTS:					
24	Kansas jurisdictional transition costs for Great					
25	Plains Energy's acquisition of Aquila, to be					
26	amortized over 5 years beginning December 1, 2010.	8,833,333		920, 923	500,000	8,333,333
27						
28						
29	Missouri Case No. ER-2010-0355:					
30	Missouri jurisdictional transition costs for Great					
31	Plains Energy's acquisition of Aquila, to be					
32	amortized over 5 years beginning May 2011.	18,836,940		920, 923	967,200	17,869,740
33						
34						
35	Kansas Docket No. 10-KCPE-415-RTS:					
36	Kansas jurisdictional difference between allowed					
37	rate base and financial costs booked for Iatan 1					
38	and Iatan Common. Vintage 1 to be amortized					
39	over 47 years beginning December 1, 2010.	3,451,438		405	15,189	3,436,249
40						
41						
42						
43						
44	TOTAL	771,598,798	41,619,561		22,929,426	790,288,933

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Missouri Case No. ER-2010-0355:					
2	Missouri jurisdictional difference between allowed					
3	rate base and financial costs booked for Iatan 1					
4	and Iatan Common. Vintage 1 to be amortized over					
5	26 years beginning May 2011.	13,214,706		405	110,991	13,103,715
6						
7						
8	Missouri Case No. ER-2009-0089:					
9	Deferred refueling costs at Wolf Creek Nuclear					
10	Operating Corporation to be amortized					
11	over 5 years beginning September 1, 2009.	994,701		524, 530	78,529	916,172
12						
13						
14	Missouri Case No. ER-2009-0089:					
15	Missouri jurisdictional deferred 2007 DSM					
16	advertising costs to be amortized over 10					
17	years beginning September 1, 2009.	228,275		909	6,988	221,287
18						
19						
20	Missouri Case No. ER-2010-0355:					
21	Deferred 50% cost of the Economic Relief					
22	Pilot Program, to be amortized over 3 years					
23	beginning May 2011.	331,310		908	21,410	309,900
24						
25						
26	Missouri Case No. ER-2010-0355:					
27	Deferred costs associated with the Iatan 2 project,					
28	to be amortized over 47.7 years beginning May					
29	2011.	27,959,353		405	389,322	27,570,031
30						
31						
32	Missouri Case No. ER-2010-0355:					
33	Missouri jurisdictional deferred 2010 DSM					
34	advertising costs to be amortized over 10 years					
35	beginning May 2011.	226,502		909	5,759	220,743
36						
37						
38	Other/Minor Regulatory Asset Items	548,954	394	524, 921	274,477	274,871
39						
40						
41						
42						
43						
44	TOTAL	771,598,798	41,619,561		22,929,426	790,288,933

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	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	Emissions Allowance Transactions per					
2	Missouri Order ER-2010-0355 and					
3	Kansas Order 10-KCPE-415-RTS, with					
4	Kansas emission allowances to be amortized					
5	over 22 years beginning December 1, 2010					
6	and Missouri emission allowances to be					
7	amortized over 21 years beginning May 2011.	83,970,422	501, 509	995,851		82,974,571
8						
9						
10	Deferred Regulatory Liability - ASC 740	103,955,261	190	693,710		103,261,551
11						
12						
13	Asset Retirement Obligation related					
14	to the decommissioning trust per					
15	FERC Order 631, MO Case No. EU-2004-0294					
16	and KS Docket No. 04-WSEE-605-ACT.	51,088,239	230, 456, 524	10,229,301		40,858,938
17						
18						
19	R&D Credit Claims in accordance with					
20	MO Case No. ER-2009-0089, to be amortized					
21	over 5 years beginning September 2009.	614,684	411	48,528		566,156
22						
23						
24	Excess Missouri Wholesale Gross Margin					
25	in accordance with MO Case No. ER-2009-0089					
26	and ER-2010-0355, to be amortized over					
27	10 years beginning September 2009 and					
28	May 2011, respectively.	6,605,305	440, 442, 444	183,474	5,539	6,427,370
29						
30						
31	Excess STB Settlement in accordance with					
32	MO Case No. ER-2009-0089 and					
33	KS Docket No. 09-KCPE-246-RTS, to be					
34	amortized over 10 years in MO beginning September					
35	2009 and over 2 years in KS beginning August					
36	2009.	857,416	501	51,821		805,595
37						
38						
39	Energy Cost Adjustment					
40	KS Docket No. 07-KCPE-905-RTS	(22,865)				-22,865
1						
2						
3	Legal Fee Reimbursement per Kansas					
4	Docket 10-KCPE-415-RTS and MO Case					
41	TOTAL	251,172,310		12,482,483	217,099	238,906,926

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
5	No. ER-2010-0355, with Kansas to be					
6	amortized over 3 years beginning December					
7	1, 2010 and Missouri to be amortized over					
8	3 years beginning May 2011.	1,466,583	923	138,047		1,328,536
9						
10						
11	One KC Place Lease Abatement per Kansas					
12	Docket No. 10-KCPE-415-RTS and Missouri					
13	Case No. ER-2010-0355, with Kansas to be					
14	amortized over 4 years beginning December 1,					
15	2010 and Missouri to be amortized over 5					
16	years beginning May 2011.	2,397,454	931	141,751		2,255,703
17						
18						
19	OPEB Liabilities in accordance with Missouri					
20	Case No. ER-2010-0355 and Kansas Docket					
21	No. 10-KCPE-415-RTS.	239,811			211,560	451,371
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	251,172,310		12,482,483	217,099	238,906,926

Schedule Page: 278 Line No.: 10 Column: f

Excess taxes due to change in tax rates	$21.2 Million
Investment tax credits	$13.8 Million
R&D Credits	$0.4 Million
Advance Coal Credits	$67.9 Million
Total	$103.3 Million

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	493,497,656	
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	500,550,208	
5	Large (or Ind.) (See Instr. 4)	93,456,626	
6	(444) Public Street and Highway Lighting	9,308,585	
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,096,813,075	
11	(447) Sales for Resale	109,507,900	
12	TOTAL Sales of Electricity	1,206,320,975	
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,206,320,975	
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,392,912	
17	(451) Miscellaneous Service Revenues	651,662	
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,495,016	
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	574,171	
22	(456.1) Revenues from Transmission of Electricity of Others	8,114,300	
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	14,228,061	
27	TOTAL Electric Operating Revenues	1,220,549,036	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
4,517,229				2
				3
5,802,017				4
1,428,150				5
65,011				6
				7
				8
				9
11,812,407				10
3,316,665				11
15,129,072				12
				13
15,129,072				14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

Line 17 (451) Miscellaneous Service Revenue:

$ 331,291	Reconnect Charges
$ 215,107	Temporary Install Charges
$ 40,615	Collection Charges
$ 29,120	Replace Damaged Meter
$ 25,082	Disconnect Service Charges
$ 10,447	OK on Arrival Fees
$ 651,662	Total

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

Line 21 (456) Other Electric Revenue:

$ 306,481	Sales & Use Tax Timely Filing Discount
$ 267,690	Returned Check Service Charges
$ 574,171	**Total**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
1	1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES	
2	Steam Power Generation - Operation (500-509)	254,447,910
3	Steam Power Generation - Maintenance (510-515)	40,781,196
4	Total Power Production Expenses - Steam Power	295,229,106
5	Nuclear Power Generation - Operation (517-525)	52,577,203
6	Nuclear Power Generation – Maintenance (528-532)	21,241,994
7	Total Power Production Expenses - Nuclear Power	73,819,197
8	Hydraulic Power Generation - Operation (535-540.1)	
9	Hydraulic Power Generation – Maintenance (541-545.1)	
10	Total Power Production Expenses – Hydraulic Power	
11	Other Power Generation - Operation (546-550.1)	15,927,841
12	Other Power Generation - Maintenance (551-554.1)	2,312,931
13	Total Power Production Expenses - Other Power	18,240,772
14	Other Power Supply Expenses	
15	Purchased Power (555)	66,724,375
16	System Control and Load Dispatching (556)	1,909,136
17	Other Expenses (557)	4,790,468
18	Total Other Power Supply Expenses (line 15-17)	73,423,979
19	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 18)	460,713,054
20	2. TRANSMISSION EXPENSES	
21	Transmission Operation Expenses	
22	(560) Operation Supervision and Engineering	768,173
23	(561) Load Dispatching	17,938
24	(561.1) Load Dispatch-Reliability	
25	(561.2) Load Dispatch-Monitor and Operate Transmission System	358,577
26	(561.3) Load Dispatch-Transmission Service and Scheduling	95,954
27	(561.4) Scheduling, System Control and Dispatch Services	3,071,831
28	(561.5) Reliability, Planning and Standards Development	
29	(561.6) Transmission Service Studies	20,385
30	(561.7) Generation Interconnection Studies	
31	(561.8) Reliability, Planning and Standards Development Services	344,721
32	(562) Station Expenses	228,487
33	(563) Overhead Line Expenses	227,931
34	(564) Underground Line Expenses	
35	(565) Transmission of Electricity by Others	14,169,885
36	(566) Miscellaneous Transmission Expenses	1,793,071
37	(567) Rents	1,803,058
38	(567.1) Operation Supplies and Expenses (Non-Major)	

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
39	TOTAL Transmission Operation Expenses (Lines 22 - 38)	22,900,011
40	Transmission Maintenance Expenses	
41	(568) Maintenance Supervision and Engineering	1,156
42	(569) Maintenance of Structures	2,728
43	(569.1) Maintenance of Computer Hardware	
44	(569.2) Maintenance of Computer Software	
45	(569.3) Maintenance of Communication Equipment	
46	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
47	(570) Maintenance of Station Equipment	568,980
48	(571) Maintenance Overhead Lines	2,622,901
49	(572) Maintenance of Underground Lines	
50	(573) Maintenance of Miscellaneous Transmission Plant	8,575
51	(574) Maintenance of Transmission Plant	
52	TOTAL Transmission Maintenance Expenses (Lines 41 - 51)	3,204,340
53	Total Transmission Expenses (Lines 39 and 52)	26,104,351
54	3. REGIONAL MARKET EXPENSES	
55	Regional Market Operation Expenses	
56	(575.1) Operation Supervision	
57	(575.2) Day-Ahead and Real-Time Market Facilitation	
58	(575.3) Transmission Rights Market Facilitation	
59	(575.4) Capacity Market Facilitation	
60	(575.5) Ancillary Services Market Facilitation	
61	(575.6) Market Monitoring and Compliance	
62	(575.7) Market Facilitation, Monitoring and Compliance Services	1,851,160
63	Regional Market Operation Expenses (Lines 55 - 62)	1,851,160
64	Regional Market Maintenance Expenses	
65	(576.1) Maintenance of Structures and Improvements	
66	(576.2) Maintenance of Computer Hardware	
67	(576.3) Maintenance of Computer Software	
68	(576.4) Maintenance of Communication Equipment	
69	(576.5) Maintenance of Miscellaneous Market Operation Plant	
70	Regional Market Maintenance Expenses (Lines 65-69)	
71	TOTAL Regional Control and Market Operation Expenses (Lines 63,70)	1,851,160
72	4. DISTRIBUTION EXPENSES	
73	Distribution Operation Expenses (580-589)	16,922,340
74	Distribution Maintenance Expenses (590-598)	19,720,623
75	Total Distribution Expenses (Lines 73 and 74)	36,642,963

Schedule Page: 324 Line No.: 37 Column: b

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for lease expense has been provided below:

CFSI Joint & Terminal Facility Charge	151,592
Cooper-Fairpoint - St. Joe-Billing for Share	205,701
Wolf Creek Line Lease	1,422,774
Total KCPL Transmission Lease Expense	1,780,067
All Other	22,991
Total KCPL Account 567000	1,803,058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

ELECTRIC CUSTOMER ACCOUNTS, SERVICE, SALES, ADMINISTRATIVE AND GENERAL EXPENSES

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)
1	(901-905) Customer Accounts Expenses	14,317,948
2	(907-910) Customer Service and Information Expenses	11,004,383
3	(911-917) Sales Expenses	276,891
4	8. ADMINISTRATIVE AND GENERAL EXPENSES	
5	Operations	
6	920 Administrative and General Salaries	39,973,792
7	921 Office Supplies and Expenses	-349,977
8	(Less) 922 Administrative Expenses Transferred-Credit	3,692,163
9	923 Outside Services Employed	11,604,809
10	924 Property Insurance	2,333,142
11	925 Injuries and Damages	5,383,885
12	926 Employee Pensions and Benefits	53,953,394
13	927 Franchise Requirements	
14	928 Regulatory Commission Expenses	8,641,643
15	(Less) 929 Duplicate Charges-Credit	46,085
16	930.1General Advertising Expenses	197,857
17	930.2Miscellaneous General Expenses	4,438,682
18	931 Rents	5,719,035
19	TOTAL Operation (Total of lines 6 thru 18)	128,158,014
20	Maintenance	
21	935 Maintenance of General Plant	3,695,855
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	131,853,869

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	Associated Electric	Kansas City Power & Light	Associated Electric	LFP
2	KCP&L GMOC-MOPUB	Kansas City Power & Light	KCP&L GMOC-MOPUB	OS
3	Ameren	Kansas City Power & Light	Ameren	LFP
4	Westar Energy	Kansas City Power & Light	Westar Energy	LFP
5	Board of Public Utilities	Kansas City Power & Light	Board of Public Utilities	LFP
6	Southwest Power Pool	Kansas City Power & Light	SPP	OS
7	City of Slater	Kansas City Power & Light	City of Slater	FNO
8	City of Prescott	Kansas City Power & Light	City of Prescott	FNO
9	City of Pomona	Kansas City Power & Light	City of Pomona	FNO
10	KEPCO	Kansas City Power & Light	KEPCO	FNO
11	Ameren	Kansas City Power & Light	Ameren	OS
12	City of Independence	Kansas City Power & Light	City of Independence	OS
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	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
89	Associated Electric	Dover, Higginsville	3	2,011	2,011	1
58	MPS Interconnects	Multiple				2
104	Ameren	Columbia, Mauer Lake	86	88,931	88,931	3
55	Westar Energy	Kaw Valley Hydro	1	539	539	4
54	Board of Public Util	Bpu-Hydro	39			5
SPP Tariff	Multiple	Multiple				6
128	City of Slater	Norton Substation				7
127	City of Prescott	Centerville Sub				8
126	City of Pomona	South Ottawa Sub				9
130	KEPCO	Multiple				10
104	Ameren	Liberty				11
101	City of Independence	Blue Valley Stm El G				12
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			129	**91,481**	**91,481**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
6,210			6,210	1
		39,426	39,426	2
263,160			263,160	3
3,374			3,374	4
118,116			118,116	5
		2,241,704	2,241,704	6
		18,902	18,902	7
		1,882	1,882	8
		7,779	7,779	9
				10
		1,752	1,752	11
		425	425	12
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390,860	**0**	**2,311,870**	**2,702,730**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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	Not Applicable				
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39					
40	TOTAL				

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	INDEPENDENCE PWR&LIGHT	OS					44,244	44,244
2	KCP&L GMO	OS					6,379	6,379
3	ENTERGY ELECTRIC SYSTEM	NF			70,428			70,428
4	MW INDEP SYSTEM OPER	NF			-1,998			-1,998
5	SOUTHWEST POWER POOL	LFP			4,464,266			4,464,266
6	SOUTHWEST POWER POOL	SFP			27,514			27,514
7	SOUTHWEST POWER POOL	NF			93,729			93,729
8	SOUTHWESTERN PUBLIC SER	LFP					931,469	931,469
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				4,653,939		982,092	5,636,031

Schedule Page: 332 Line No.: 1 Column: a

Facility Use Charge billed to KCP&L from Independence is for capacity on Independence's 161 KV transmission line from KCP&L's Blue Mills substation.

Schedule Page: 332 Line No.: 2 Column: a

Emergency and Firm Transmission Service delivered to KCP&L is for transmission capacity needed from KCP&L GMO for KCP&L to carry its load. There is no actual scheduling of energy as with usual transmission service. Energy purchases are handled through purchase power account 555.

Schedule Page: 332 Line No.: 8 Column: a

Amortization of $1,250,000 payment to Southwest Public Service for assignement of transmission paths to KCP&L. This amortization runs 9/1/2007 to 9/1/2013, as well as amortization of $1,000,000 payment for an extension contract that runs 9/1/2009 to 12/31/2011. There is a true-up in July 2011 of $798,976.60.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

Depreciation, Depletion and Amortization of Electric Plant (Accts 403, 403.1, 404, and 405) (Except Amortization of Acquisition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Other Limited-Term Electric Plant (Account 404) (e)	Amortization of Other Electric Plant (Account 405) (e)	Total (f)
1	Intangible Plant				9,420,458	9,420,458
2	Steam Production Plant	42,944,821	641,240	1,686	379,423	43,967,170
3	Nuclear Production Plant	18,156,642				18,156,642
4	Hydraulic Production Plant Conv					
5	Hydraulic Production Plant - Pumped Storage					
6	Other Production Plant	17,375,316	150,931		448	17,526,695
7	Transmission Plant	5,814,303			120,493	5,934,796
8	Distribution Plant	29,662,225			158,012	29,820,237
9	General Plant	6,436,163		1,036,109	15,380,740	22,853,012
10	Common Plant					
11	TOTAL ELECTRIC (lines 2 through 10)	120,389,470	792,171	1,037,795	25,459,574	147,679,010

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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)	798,305	1,439,515	1,190,535	
3	Net Sales (Account 447)	9,281,382	8,538,042	10,128,532	
4	Transmission Rights				
5	Ancillary Services	34,901	74,379	185,263	
6	Other Items (list separately)				
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46	TOTAL	10,114,588	10,051,936	11,504,330	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

MONTHLY PEAKS AND OUTPUT

(1) (1) Report the monthly peak load and energy output. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non- integrated system. In quarter 1 report January, February, and March only. In quarter 2 report April, May, and June only. In quarter 3 report July, August, and September only.
(2) Report on column (b) by month the system's output in Megawatt hours for each month.
(3) Report on column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on columns (e) and (f) the specified information for each monthly peak load reported on column (d).
(6) Report Monthly Peak Hours in military time; 0100 for 1:00 AM, 1200 for 12 AM, and 1830 for 6:30 PM, etc.

NAME OF SYSTEM: KCP&L TOTAL COMPANY

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
1	January	1,977,217	494,309	2,741	13	800
2	February	1,663,821	398,282	2,843	8	1900
3	March	1,499,111	267,908	2,241	9	1900
4	Total	5,140,149	1,160,499	7,825		
5	April	1,342,427	259,694	2,062	10	1700
6	May	1,616,692	401,491	3,026	10	1700
7	June	1,902,394	362,790	3,590	30	1700
8	Total	4,861,513	1,023,975	8,678		
9	July	2,212,952	300,132	3,814	27	1700
10	August	1,997,226	309,351	3,913	1	1700
11	September	1,655,598	440,375	3,724	1	1700
12	Total	5,865,776	1,049,858	11,451		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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: Kansas City Power & 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	2,741	13	800	2,548	62		131		
2	February	2,843	8	1900	2,646	66		131		
3	March	2,241	9	1900	2,058	51		132		
4	Total for Quarter 1	7,825			7,252	179		394		
5	April	2,062	10	1700	1,882	48		132		
6	May	3,026	10	1700	2,828	67		131		
7	June	3,590	30	1700	3,364	95		131		
8	Total for Quarter 2	8,678			8,074	210		394		
9	July	3,814	27	1700	3,577	105		132		
10	August	3,913	1	1700	3,675	107		131		
11	September	3,724	1	1700	3,477	115		132		
12	Total for Quarter 3	11,451			10,729	327		395		
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year	27,954			26,055	716		1,183		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	11/29/2011	End of 2011/Q3

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: Kansas City Power & LIght Company

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									

Schedule — Page No.

Accrued and prepaid taxes 262-263
Accumulated Deferred Income Taxes 234
272-277
Accumulated provisions for depreciation of
common utility plant 356
utility plant 219
utility plant (summary) 200-201
Advances
from associated companies 256-257
Allowances 228-229
Amortization
miscellaneous 340
of nuclear fuel 202-203
Appropriations of Retained Earnings 118-119
Associated Companies
advances from 256-257
corporations controlled by respondent 103
control over respondent 102
interest on debt to 256-257
Attestation i
Balance sheet
comparative 110-113
notes to 122-123
Bonds 256-257
Capital Stock 251
expense 254
premiums 252
reacquired 251
subscribed 252
Cash flows, statement of 120-121
Changes
important during year 108-109
Construction
work in progress - common utility plant 356
work in progress - electric 216
work in progress - other utility departments 200-201
Control
corporations controlled by respondent 103
over respondent 102
Corporation
controlled by 103
incorporated 101
CPA, background information on 101
CPA Certification, this report form .... i-ii

Schedule	Page No.
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219 336-337
Directors	105
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	101
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101

Schedule	Page No.
Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337 401-429

Schedule	Page No.
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation	
amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred	
income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income	
from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Substations	426
Supplies - materials and	227

Schedule	Page No.
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230