e·on | U.S.

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
JUN 30 2009
PUBLIC SERVICE COMMISSION

E.ON U.S. LLC
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.eon-us.com

Rick E. Lovekamp
Manager – Regulatory Affairs
T 502-627-3780
F 502-627-3213
rick.lovekamp@eon-us.com

June 30, 2009

Re: E.ON AG, E.ON U.K. Ltd (formerly PowerGen plc), E.ON U.S. LLC (formerly LG&E Energy LLC), Louisville Gas and Electric Company, and Kentucky Utilities Company (Case Nos. 10296, 89-374, 97-300, 2000-095 and 2001-104)

Dear Mr. DeRouen:

Pursuant to the Commission's Order in the aforementioned proceedings, the Companies do hereby file an original and two (2) copies of the Companies' Annual Accounting Information Filing. Additionally, pursuant to case No. 2001-104 – Appendix A: Reporting Requirements – Reporting No. 23, the Companies are filing three (3) copies of E.ON AG's 2008 Financial and Company Reports.

Please confirm your receipt of this filing by placing the File Stamp of your Office with date received on the extra copies. Should you have any questions regarding the information filed herewith, please call me or Don Harris at (502) 627-2021.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

E.ON AG,
E.ON U.K. Ltd (*formerly Powergen ltd*),
E.ON U.S. LLC (*formerly LG&E Energy LLC*),
E.ON U.S. Services Inc. (*formerly LG&E Energy Services, Inc.*),
Louisville Gas and Electric Company,
and
Kentucky Utilities Company

Annual Accounting Information Filing Pursuant To Case Nos. 10296, 89-374, 97-300, 2000-095 and 2001-104

YEAR ENDED DECEMBER 31, 2008

Filed: June 2009

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FINANCIAL STATEMENTS

MARCH 31, 2008

Kentucky Utilities Company

Financial Statements and Additional Information

As of March 31, 2008 and 2007

INDEX OF ABBREVIATIONS

ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
Company	KU
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EUSIC	E.ON US Investments Corp.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation
GHG	Greenhouse Gas
IRS	Internal Revenue Service
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
kWh	Kilowatt Hours
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Units
Moody's	Moody's Investor Services, Inc.
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
Virginia Commission	Virginia State Corporation Commission

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Financial Statements (Unaudited)

Kentucky Utilities Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
OPERATING REVENUES:		
Total operating revenues	$ 352	$ 316
OPERATING EXPENSES:		
Fuel for electric generation	123	109
Power purchased	56	45
Other operation and maintenance expenses	66	59
Depreciation and amortization	32	28
Total operating expenses	277	241
OPERATING INCOME	75	75
Other expense (income) - net	(9)	(6)
Interest expense (Notes 3 and 6)	4	5
Interest expense to affiliated companies (Note 8)	12	7
INCOME BEFORE INCOME TAXES	68	69
Federal and state income taxes (Note 5)	22	24
NET INCOME	$ 46	$ 45

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Balance at beginning of period	$1,037	$ 870
Net income	46	45
Balance at end of period	$1,083	$ 915

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	March 31, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ -	$ -
Restricted cash	6	11
Accounts receivable – less reserves of $2 million as of March 31, 2008 and December 31, 2007	162	172
Accounts receivable from affiliated companies (Note 8)	1	17
Materials and supplies:		
Fuel (predominantly coal)	37	42
Other materials and supplies	34	34
Prepayments and other current assets	4	12
Total current assets	244	288
Other property and investments	29	29
Utility plant:		
At original cost	5,100	4,939
Less: reserve for depreciation	1,648	1,622
Net utility plant	3,452	3,317
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	28	28
Other	78	86
Cash surrender value of key man life insurance	37	37
Other assets	12	11
Total deferred debits and other assets	155	162
Total assets	3,880	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	March 31, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 33	$ 33
Notes payable to affiliated companies (Notes 6 and 8)	50	23
Accounts payable	146	160
Accounts payable to affiliated companies (Note 8)	29	48
Customer deposits	20	20
Accrued income taxes	19	-
Other current liabilities	22	28
Total current liabilities	319	312
Long-term debt:		
Long-term debt (Note 6)	300	300
Long-term debt to affiliated company (Notes 6 and 8)	931	931
Total long-term debt	1,231	1,231
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	281	285
Accumulated provision for pensions and related benefits (Note 4)	84	83
Investment tax credit (Note 5)	58	55
Asset retirement obligation	31	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	314	310
Deferred income taxes - net	21	22
Other	12	10
Other liabilities	23	23
Total deferred credits and other liabilities	824	818
Common equity:		
Common stock, without par value – Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital	115	90
Retained earnings	1,062	1,016
Undistributed subsidiary earnings	21	21
Total retained earnings	1,083	1,037
Total common equity	1,506	1,435
Total liabilities and equity	$ 3,880	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Three Months Ended March 31, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 46	$ 45
Items not requiring cash currently:		
Depreciation and amortization	32	28
Investment tax credit	3	10
Other	(4)	(3)
Changes in current assets and liabilities:		
Accounts receivable	26	33
Material and supplies	5	10
Accounts payable	(10)	(2)
Accrued income taxes	19	7
Prepayments and other current assets	8	7
Other current liabilities	(7)	(1)
Pension and postretirement funding	1	(13)
Fuel adjustment clause receivable, net	11	(6)
Other	(3)	(2)
Net cash provided by operating activities	127	113
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(184)	(125)
Change in restricted cash	5	2
Net cash used for investing activities	(179)	(123)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirement of first mortgage bonds (Note 6)	-	(107)
Issuance of pollution control bonds	-	54
Additional paid-in capital	25	-
Long-term borrowings from affiliated company (Note 8)	-	128
Short-term borrowings from affiliated company (Note 6)	291	211
Repayment of short-term borrowings from affiliated company (Note 6)	(264)	(276)
Net cash provided by in financing activities	52	10
CHANGE IN CASH AND CASH EQUIVALENTS	-	-
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	-	6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ -	$ 6

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Notes to Financial Statements
(Unaudited)

Note 1 - General

The unaudited financial statements include the accounts of the Company. KU's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted, although the Company believes that the disclosures are adequate to make the information presented not misleading. These unaudited financial statements and notes should be read in conjunction with the Company's annual report for the year ended December 31, 2007, including management's discussion and analysis and the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 was adopted effective January 1, 2008 and had no impact on the statements of operations, financial position and cash flows.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, the Company will provide additional disclosures relating to its financial derivatives, AROs and pension assets, as required, in 2008.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to KU's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in KU's Balance Sheets:

Kentucky Utilities Company
(unaudited)

(in millions)	March 31, 2008	December 31, 2007
ARO	$ 25	$ 24
Unamortized loss on bonds	10	10
MISO exit	19	20
FAC	5	17
ECR	14	11
Other	5	4
Subtotal	78	86
Pension and postretirement benefits	28	28
Total regulatory assets	$ 106	$ 114
Accumulated cost of removal of utility plant	$ 314	$ 310
Deferred income taxes – net	21	22
Other	12	10
Total regulatory liabilities	$ 347	$ 342

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset which represents the changes in funded status of the plans. The Company will seek recovery in future proceedings with the Kentucky and Virginia Commissions. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. KU will seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. KU currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit and deferred storm costs. Other regulatory liabilities include DSM and MISO costs currently included in base rates that will be netted against costs of withdrawing from the MISO in the next rate case.

MISO Exit. KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, KU paid approximately $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of $1 million and will provide an estimated $3 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which may continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in KU's next rate case, however, the Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. A public hearing was held in March 2008. An order is anticipated in the third quarter of 2008.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. A public hearing was held in October 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The factor may be adjusted annually for over-or-under collections of fuel costs from the prior year. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008, customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application. The recommended change, which KU has agreed to, would result in a decrease of 0.482 cents/kWh and will become effective beginning in June 2008 pending Virginia Commission approval. A public hearing was held in May 2008, and an order is anticipated in the second quarter of 2008.

ECR. In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. All parties to the case submitted requests with the Kentucky Commission to waive rights to a hearing on this matter. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review period, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Other Regulatory Matters

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by KU and LG&E, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005, and was never appealed.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, KU, LG&E and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. KU, LG&E and the Kentucky Commission filed for reconsideration of the appellate court's ruling, but those requests were denied in April 2008. KU and LG&E will file a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line (all rights of way for the other line have been acquired), a Meade County, Kentucky circuit court judge issued a ruling upholding the objections of two co-owners of the property crossed by the easement and dismissed that eminent domain proceeding pending the completion of the CCN appeal described above. KU and LG&E have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the eminent domain litigation. Additional condemnation proceedings involving other parcels of property to support this same transmission line are also pending in neighboring Hardin County, and three landowners there have now sought dismissal of certain of those proceedings in Hardin County, on the same grounds cited by the Meade County court. KU and LG&E have opposed those efforts to dismiss, and are awaiting ruling by the Hardin County Circuit Court.

Merger Surcredit. In December 2007, KU submitted to the Kentucky Commission its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. The Kentucky Commission issued a procedural schedule for this proceeding in March 2008, with data discovery to be completed in May 2008. A public hearing is scheduled in May 2008, and an order is expected by the end of the second quarter of 2008.

DSM. In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the Electric Reliability Organization, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. The SERC is currently assessing KU's compliance with certain existing mitigation plans resulting from a prior RRO's audit of various reliability standards, and KU and SERC are in discussions regarding potential settlement, further mitigation steps or other resolution actions regarding these items. While KU believes itself to be in substantial compliance with the mandatory reliability standards, KU cannot predict the outcome of the current SERC proceeding or of other analysis which may be conducted regarding compliance with particular reliability standards.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received by the Kentucky Commission, the timing of which cannot currently be determined. KU also filed the depreciation study with the Virginia Commission, but has not requested formal review and approval of the depreciation rates from the Virginia Commission. Such a review will take place either during KU's next base rate case in Virginia or when KU makes a formal application to the Virginia Commission for approval of the proposed rates.

Brownfield Development Rider Tariff. In March 2008, KU and LG&E received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. Data discovery concluded in July 2007, and no parties to the case requested a hearing. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU, for implementation within approximately eight months, for its large commercial and industrial customers.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave Virginia customers the ability to choose their electric supplier. Rates are capped at current levels through December 2010. In April 2007, Virginia passed legislation terminating this competitive market and commencing re-regulation of utility rates in Virginia. The new act will end the cap on rates at the end of 2008, rather than through December 2010, and end customer choice for most consumers in the applicable regions of the state. Thereafter, a hybrid model of regulation is expected to apply in Virginia, whereby utility rates would be reviewed every two years and a utility's rate of return on equity shall not be set lower than the average of the rates of return for other regional utilities, with certain caps, floors or adjustments. The legislation was effective in July 2007, and also includes a 10% nonbinding goal for renewable power generation by 2022, as well as incentives for new generation, including renewables. Under the legislation, KU retains an existing exemption from customer choice and other restructuring activities as applicable to KU's limited service territory in Virginia. However, subject to future developments, KU may or may not undertake such a rate proceeding in the first six months of 2009 based on calendar year 2008 financial data under the hybrid model of regulation, or make biennial rate filings with the Virginia Commission thereafter.

Note 3 - Financial Instruments

Effective January 1, 2008, KU adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2.

Energy Trading and Risk Management Activities (non-hedging derivatives). KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

The table below summarizes KU's energy trading and risk management activities for the three months ended March 31, 2007:

(in millions)	
Fair value of contracts at beginning of period, net asset	$ 1
Unrealized gains and losses recognized at contract inception during the period	-
Realized gains and losses recognized during the period	-
Changes in fair values attributable to changes in valuation techniques and assumptions	(2)
Other unrealized gains and losses and changes in fair values	-
Fair value of contracts at end of period, net (liability) asset	$ (1)

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at March 31, 2007, had a maturity of less than one year. There were no contracts outstanding at March 31, 2008. All amounts for 2008 are less than $1 million. Energy trading and risk management contracts are valued using Level 1, prices actively quoted for proposed or executed transactions or quoted by brokers.

Note 4 - Pension and Other Postretirement Benefit Plans

The following table provides the components of net periodic benefit cost for pension and other benefit plans for the three months ended March 31:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2008	2007	2008	2007
Service cost	$ 1	$ 2	$ -	$ 1
Interest cost	5	6	1	1
Expected return on plan assets	(5)	(7)	-	-
Amortization of actuarial loss	-	1	-	-
Benefit cost year-to-date	$ 1	$ 2	$ 1	$ 2

Net periodic benefit costs incurred by employees of KU are reflected in both utility plant on the balance sheet and in operating expense on the income statement. The above costs do not include allocations of net periodic benefit costs from affiliates whose employees provide services to KU.

The pension plans are funded in accordance with all applicable requirements of the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. In March 2008, KU made contributions to other postretirement benefit plans of approximately $1 million. KU anticipates making further voluntary contributions in 2008 to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the postretirement medical account under the pension plan up to the maximum amount allowed by law.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including KU, will calculate its separate income tax for the tax period. The resulting separate-return tax cost or benefit will be paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. With few exceptions, KU is no longer subject to U.S. federal income tax examinations for years before 2004. Statutes of limitations related to 2004 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to the actual calendar year applicable to the return and ends 90 days after the return is filed.

KU adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million, and are based on the expiration of statutes during 2008.

KU, upon adoption of FIN 48, adopted a new financial statement classification for interest and penalties. Prior to the adoption of FIN 48, KU recorded interest and penalties for income taxes on the income statement in income tax expense and in the taxes accrued balance sheet account, net of tax. Upon adoption of FIN 48, interest is recorded as interest expense and penalties are recorded as operating expenses on the income statement and accrued expenses in the balance sheets, on a pre-tax basis. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes.

The amount KU recognized as interest accrued related to unrecognized tax benefits in interest expense in operating expenses was less than $1 million at March 31, 2008 and March 31, 2007. At the date of adoption, KU accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by KU upon adoption of FIN 48, or through March 31, 2008.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $3 million and $10 million during the three months ended March 31, 2008 and March 31, 2007, respectively, decreasing current federal income taxes.

In March 2008, certain groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was violative of certain environmental laws and demanded relief, including suspension or termination of the program. KU is monitoring, but is not currently a party to, this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 – Short-Term and Long-Term Debt

KU's long-term debt includes $33 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County Series 2002 A and B, Muhlenberg County Series 2002 A and Mercer County Series 2002 A. These bonds mature in 2032. KU does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the three months ended March 31, 2008, was 2.30%.

During June 2007, KU entered into a short-term bilateral line of credit facility totaling $35 million. There was no outstanding balance under this facility at March 31, 2008. During the third quarter of 2007, KU extended the maturity date of this facility through June 2012.

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless KU defaults on the loan agreement. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets. At March 31, 2008 and December 31, 2007, KU had $6 million and $11 million, respectively, of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At March 31, 2008, KU had an aggregate $333 million of outstanding pollution control indebtedness, of which $300 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" when there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the three months ended March 31, 2008 and March 31, 2007, the average rate on the auction rate bonds was 4.82% and 3.66%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first quarter of 2008, the ratings of the Carroll County 2004 Series A bonds were downgraded from AAA to AA and subsequently to A and then to BBB+ by S&P and from Aaa to A2 by Moody's, and the Carroll County 2006 Series C bonds were downgraded from Aaa to A2 by Moody's and from AAA to A- by S&P due to downgrades of the bond insurer. In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. The conversion was completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively. In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bonds and the Mercer County 2000 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent. KU will hold some or all of such bonds until a later date, at which time KU may refinance or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps KU has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructuring or redemption and refinancing, could result in KU incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures. See Note 9, Subsequent Events.

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances were as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
March 31, 2008	$400	$ 50	$350	3.08%
December 31, 2007	$400	$ 23	$377	4.75%

E.ON U.S. maintains a revolving credit facility totaling $311 million at March 31, 2008 and $150 million at December 31, 2007, with an affiliated company, E.ON North America, Inc., to ensure funding availability for the money pool. The balance is as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
March 31, 2008	$311	$94	$217	3.36%
December 31, 2007	$150	$62	$ 88	4.97%

There were no redemptions or issuances of long-term debt year-to-date through March 31, 2008.

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in KU's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of KU contained therein). See the above-referenced notes in KU's Annual Report regarding such commitments or contingencies.

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in this proceeding denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages. During 2005, the FERC declined KU's application to exercise exclusive jurisdiction on matters. In July 2005, the district court resolved a summary judgment motion made by KU in OMU's favor, ruling that a contractual provision grants OMU the ability to terminate the contract without cause upon four years' prior notice, for which ruling KU retains certain rights to appeal. A motion to reconsider that ruling is presently pending before the Court. The parties are continuing various discovery proceedings, as well as settlement negotiations. A trial date has been set for October 2008. In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding. The Company is currently unable to determine the final outcome of this matter.

Construction Program. KU had approximately $440 million of commitments in connection with its construction program at March 31, 2008.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division for Air Quality in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the Kentucky Division for Air Quality issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. The final rule is currently under challenge. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. KU's weighted-average company-wide emission rate for SO_2 in the first quarter of 2008 was approximately 1.32 lbs./MMBtu of heat input, with every generating unit below its emission limit established by the Kentucky Division for Air Quality. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. In February 2008, a federal appellate court issued a decision vacating the CAMR, but the EPA and other parties have filed a motion for rehearing. Depending on the final outcome of the pending appeal, the CAMR could be superceded by new mercury reduction rules with different or more stringent requirements. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAMR, but those state requirements are likely to be revised to reflect the outcome of the challenge to the CAMR at the federal level.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2007 time period at a cost of $220 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve the emissions reductions mandated by the CAIR, KU expects to incur additional capital expenditures totaling approximately $675 million during the 2008 through 2010 time period for pollution controls, including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the U.S. Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. The parties are currently proceeding with discovery while concurrently discussing settlement. A $2 million accrual has been recorded based on the current status of those discussions, however, KU cannot determine the overall outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. The Companies have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have conducted an initial meeting on this matter. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and ongoing claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 8 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Note 9 – Subsequent Events

On April 16, 2008, the Carroll County 2006 Series C bonds converted from an auction rate mode to a weekly interest rate mode. In connection with the conversion, KU purchased the bonds from the remarketing agent.

On May 1, 2008, the Mercer County 2000 Series A bonds converted from an auction rate mode to a weekly interest rate mode. In connection with the conversion, KU purchased the bonds from the remarketing agent.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during the three month period ended March 31, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of December 31, 2007, KU provided electricity to approximately 506,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. KU's coal-fired electric generating plants produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution of natural gas in Kentucky.

Environmental Matters

Protection of the environment is a major priority for KU. Federal, state and local regulatory agencies have issued KU permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Net Income

Net income for the three months ended March 31, 2008, increased $1 million compared to the same period in 2007. The increase was primarily the result of increased electric revenues ($36 million), increased other income ($3 million) and decreased income taxes ($2 million), partially offset by increased operating expenses ($36 million) and increased interest expense, including interest expense to affiliated companies ($4 million).

Revenues

Revenues in the three months ended March 31, 2008, increased $36 million primarily due to:

- Increased fuel costs ($17 million) billed to customers through the FAC due to higher fuel costs (coal and natural gas) and higher transportation costs
- Increased ECR surcharge ($14 million) due to increased recoverable capital spending
- Increased sales volumes delivered ($8 million) resulting from an 8% increase in heating degree days in the first quarter of 2008 as compared to the same period in 2007
- Decreased wholesale and transmission revenues ($3 million) due to decreased power available for wholesale sales as a result of higher native load demand and lower transmission rates

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $14 million in the three months ended March 31, 2008, primarily due to:

- Increased generation to meet sales ($9 million), due to 8% more heating degree days
- Increased spot market pricing for coal/natural gas generation ($5 million) due to mine safety compliance costs and higher transportation costs

Purchased power expense increased $11 million in the three months ended March 31, 2008, primarily due to:

- Increased cost per mWh of purchases ($17 million) due to increased third party purchases and higher fuel prices
- Decreased volumes purchased ($6 million) due to increased internal generation as a result of higher native load demand

Other operation and maintenance expenses increased $7 million in the three months ended March 31, 2008, primarily due to increased other operation expenses ($4 million) and increased maintenance expenses ($3 million).

Other operation expenses increased $4 million in the three months ended March 31, 2008, primarily due to:

- Increased generation, transmission and distribution expenses, including labor for storm restoration ($2 million)
- Increased outside services ($1 million)
- Increased expense for uncollectible accounts ($1 million)

Maintenance expenses increased $3 million in the three months ended March 31, 2008, primarily due to increased contractor and overtime labor expense for storm restoration

Interest expense, including interest expense to affiliated companies, increased $4 million in the three months ended March 31, 2008, primarily due to:

- Increased interest expense to affiliated companies ($5 million) due to increased affiliate borrowings
- Decreased interest expense ($1 million) due to the refinancing of First Mortgage bonds with loans from Fidelia and defeasance of pollution control bonds ($2 million), partially offset by higher interest rates on auction rate pollution control bonds ($1 million)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	3.1	3.7
Amortization of investment tax credits	(0.1)	(0.1)
EEI Dividend	(3.5)	(2.5)
Other differences	(2.1)	(1.3)
Effective income tax rate	32.4%	34.8%

The effective income tax rate decreased for the three months ended March 31, 2008 compared to the three months ended March 31, 2007, due primarily to an increase in dividends received from EEI, a decrease in Other Differences due to an increase in Section 199, Manufacturing deduction and a decrease in state income taxes net of federal benefit due to an increase in state coal credits.

Liquidity and Capital Resources

KU uses net cash generated from its operations and external financing (including financing from affiliates) to fund construction of plant and equipment and the payment of dividends. KU believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was $127 million and $113 million for the three months ended March 31, 2008 and 2007, respectively.

The 2008 increase of $14 million was primarily the result of increases in cash due to changes in:

- FAC receivable, net ($17 million)
- Pension and postretirement funding ($14 million) due to higher pension funding in 2007
- Accrued income taxes ($12 million)
- Prepayments and other current assets ($1 million)

These increases were partially offset by cash provided by changes in:

- Accounts payable ($8 million)
- Accounts receivable ($7 million)
- Other current liabilities ($6 million)
- Materials and supplies ($5 million)
- Earnings, net of non-cash items ($3 million)
- Other ($1 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $184 million and $125 million in the three months ended March 31, 2008 and 2007, respectively. Net cash used for investing activities increased $56 million in the three months ended March 31, 2008, compared to 2007 primarily due to increased capital expenditures of $59 million. Restricted cash increased $3 million and represents the escrowed proceeds of the Pollution Control Bonds issued which are disbursed as qualifying costs are incurred.

Financing Activities

Net cash inflows from financing activities were $52 million and $10 million in the three months ended March 31, 2008 and 2007, respectively.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

KU expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $1,465 million, consisting primarily of construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $425 million, construction of TC2 totaling approximately $360 million, the Brown ash pond totaling approximately $40 million, a customer care system totaling approximately $25 million and on-going construction related to generation and distribution assets.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

KU has a variety of funding alternatives available to meet its capital requirements. KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds of up to $400 million available to KU at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Note 6 of Notes to Financial Statements.

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See Note 7 of Notes to Financial Statements for current commitments. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Regulatory approvals are required for KU to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In

November 2007, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2009 allowing short-term borrowing of up to $400 million.

KU's debt ratings as of March 31, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework . The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company's internal control over financial reporting that occurred during the quarter ended March 31, 2008, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

KU is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Legal Proceedings

For a description of the significant legal proceedings involving KU, reference is made to the information under the following captions of KU's Annual Report for the year ended December 31, 2007: Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in KU's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, KU believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

FINANCIAL STATEMENTS

JUNE 30, 2008

Kentucky Utilities Company

Financial Statements and Additional Information

As of June 30, 2008 and 2007

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Financial Statements (Unaudited)

Kentucky Utilities Company

Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
OPERATING REVENUES:				
Total operating revenues	$ 316	$ 301	$ 668	$ 618
OPERATING EXPENSES:				
Fuel for electric generation	110	107	233	217
Power purchased	54	45	110	90
Other operation and maintenance expenses	75	63	141	121
Depreciation and amortization	31	29	63	58
Total operating expenses	270	244	547	486
OPERATING INCOME	46	57	121	132
Other expense (income) – net	(9)	(9)	(18)	(15)
Interest expense (Notes 3, 5 and 6)	3	3	7	7
Interest expense to affiliated companies (Note 8)	13	10	26	18
INCOME BEFORE INCOME TAXES	39	53	106	122
Federal and state income taxes (Note 5)	11	18	32	42
NET INCOME	$ 28	$ 35	$ 74	$ 80

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Balance at beginning of period	$1,083	$ 915	$1,037	$ 870
Net income	28	35	74	80
Balance at end of period	$1,111	$ 950	$1,111	$ 950

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	June 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ -	$ -
Restricted cash	-	11
Accounts receivable – less reserves of $3 million and $2 million as of June 30, 2008 and December 31, 2007, respectively	161	172
Accounts receivable from affiliated companies (Note 8)	-	17
Materials and supplies:		
Fuel (predominantly coal)	56	42
Other materials and supplies	35	34
Prepayments and other current assets	7	12
Total current assets	259	288
Other property and investments	30	29
Utility plant:		
At original cost	5,295	4,939
Less: reserve for depreciation	1,674	1,622
Net utility plant	3,621	3,317
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	28	28
Other	88	86
Cash surrender value of key man life insurance	37	37
Other assets	11	11
Total deferred debits and other assets	164	162
Total assets	$ 4,074	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	June 30, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 33	$ 33
Notes payable to affiliated companies (Notes 6 and 8)	75	23
Accounts payable	173	160
Accounts payable to affiliated companies (Note 8)	50	48
Customer deposits	20	20
Other current liabilities	25	28
Total current liabilities	376	312
Long-term debt:		
Long-term debt (Note 6)	270	300
Long-term debt to affiliated company (Notes 6 and 8)	1,006	931
Total long-term debt	1,276	1,231
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	279	285
Accumulated provision for pensions and related benefits (Note 4)	87	83
Investment tax credit (Note 5)	68	55
Asset retirement obligation	31	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	318	310
Deferred income taxes - net	19	22
Other	15	10
Other liabilities	21	23
Total deferred credits and other liabilities	838	818
Common equity:		
Common stock, without par value –		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital	165	90
Retained earnings	1,090	1,016
Undistributed subsidiary earnings	21	21
Total retained earnings	1,111	1,037
Total common equity	1,584	1,435
Total liabilities and equity	$ 4,074	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Six Months Ended June 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 74	$ 80
Items not requiring cash currently:		
Depreciation and amortization	63	58
Deferred income taxes – net	(9)	-
Investment tax credit – net	13	20
Other	(6)	(8)
Changes in current assets and liabilities:		
Accounts receivable	28	8
Material and supplies	(15)	(3)
Accounts payable	24	40
Prepayments and other current assets	4	(16)
Other current liabilities	(3)	(4)
Pension funding	-	(13)
Fuel adjustment clause receivable, net	6	(9)
Other	8	(6)
Net cash provided by operating activities	187	147
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(360)	(319)
Asset transferred from affiliate (Note 8)	(10)	-
Change in restricted cash	11	(23)
Net cash used for investing activities	(359)	(342)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirement of first mortgage bonds	-	(107)
Issuance of pollution control bonds	-	81
Additional paid-in capital	75	-
Long-term borrowings from affiliated company (Note 6)	75	178
Short-term borrowings from affiliated company - net (Note 6)	52	43
Reacquired bonds	(30)	-
Net cash provided by financing activities	172	195
CHANGE IN CASH AND CASH EQUIVALENTS	-	-
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	-	6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ -	$ 6

The accompanying notes are an integral part of these financial statements.

Note 1 - General

The unaudited financial statements include the accounts of the Company. KU's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted, although the Company believes that the disclosures are adequate to make the information presented not misleading. These unaudited financial statements and notes should be read in conjunction with the Company's annual report for the year ended December 31, 2007, including management's discussion and analysis and the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

<u>SFAS No. 161</u>

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

<u>SFAS No. 160</u>

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

<u>SFAS No. 159</u>

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 was adopted effective January 1, 2008 and had no impact on the statements of operations, financial position and cash flows.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives, AROs and pension assets, as required, are now provided.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to KU's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in KU's Balance Sheets:

Kentucky Utilities Company
(unaudited)

(in millions)	June 30, 2008	December 31, 2007
ARO	$ 25	$ 24
Unamortized loss on bonds	11	10
MISO exit	19	20
FAC	11	17
ECR	18	11
Other	4	4
Subtotal	88	86
Pension and postretirement benefits	28	28
Total regulatory assets	$ 116	$ 114
Accumulated cost of removal of utility plant	$ 318	$ 310
Deferred income taxes – net	19	22
Other	15	10
Total regulatory liabilities	$ 352	$ 342

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. The Company will seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. KU will seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. KU currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit and deferred storm costs. Other regulatory liabilities include DSM and MISO costs currently included in base rates that will be netted against costs of withdrawing from the MISO in the next base rate case.

MISO Exit. KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, KU paid approximately $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of $1 million and will provide an estimated $3 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in KU's next base rate case, however, the Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in June 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The factor may be adjusted annually for over- or under-collections of fuel costs from the prior year. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008, customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kWh from the factor in effect for the April 2007 through March 2008 period.

ECR. In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of KU's environmental surcharge. An order is anticipated by the end of the year.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Other Regulatory Matters

Base Rate Case. In July 2008, KU filed an application with the Kentucky Commission for an increase in base rates. See Note 9, Subsequent Events.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by KU and LG&E, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, KU, LG&E and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. KU, LG&E and the Kentucky Commission filed for reconsideration of the appellate court's ruling, but those requests were denied in April 2008. KU and LG&E filed a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal, which motion has been opposed by the counter-parties.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. All rights of way for one transmission line have been acquired. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line, a Meade County, Kentucky circuit court judge issued a ruling upholding the objections of two co-owners of the property crossed by the easement and dismissed that eminent domain proceeding pending the completion of the CCN appeal described above. KU and LG&E have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the eminent domain litigation. Additional condemnation proceedings involving other parcels of property to support this transmission line are also pending in neighboring Hardin County where three landowners have challenged KU's and LG&E's right to easements, on the same grounds cited by the Meade County court and other purported basis. In May and June 2008, the Hardin County Circuit Court issued rulings denying the dismissal motions, finding that KU and LG&E had established their condemnation rights and granting judgment in favor of KU and LG&E. During July 2008, the landowners filed subsequent motions in Hardin Circuit Court seeking to further challenge KU's and LG&E's condemnation right by asserting deficiencies in the air permit relating to the proposed TC2 generation unit. KU and LG&E continue to engage in settlement negotiations with the property owners. In a separate, further proceeding, certain landowners have filed a lawsuit in federal court against the U.S. Army, KU and LG&E alleging that the U.S. Army failed to comply with Section 106 of the National Historic Preservation Act in granting an easement across Fort Knox. KU and LG&E are working with the U.S. Army in defending against the claims.

Merger Surcredit. In December 2007, KU submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008, to the Kentucky Commission. In June 2008, the Kentucky Commission issued an Order approving a settlement which provides for continuation of the merger surcredit for the period July 2008 through January 2009, which surcredits will terminate in connection with any new base rates to go into effect after January 2009. See Note 9, Subsequent Events.

VDT. In accordance with the Kentucky Commission's Order dated March 24, 2006, the VDT will terminate in the first billing month after the filing for a change in base rates. As a result of KU's filing of its application with the Kentucky Commission for an increase in base rates in July 2008, the VDT terminated with the first billing cycle in August 2008, subject to a final balancing adjustment in September 2008.

DSM. In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the Electric Reliability Organization, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. The SERC has assessed KU's compliance with certain existing mitigation plans relating to two standards resulting from a prior RRO's audit of various reliability standards, and the parties agreed in principle to a penalty of less than $1 million in June 2008. While KU believes itself to be in substantial compliance with the mandatory reliability standards, KU cannot predict the outcome of other analyses, including on-going SERC reviews relating to six additional standards, which may be conducted regarding compliance with particular reliability standards.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission, the timing of which cannot currently be determined. A revised procedural schedule was issued in June 2008, but a hearing is not currently scheduled. In July 2008, KU filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. The Kentucky Commission has not yet ruled on the request. KU also filed the depreciation study with the Virginia Commission, but has not requested formal review and approval of the depreciation rates from the Virginia Commission. Such a review will take place either during KU's next base rate case in Virginia or when KU makes a formal application to the Virginia Commission for approval of the proposed rates.

Brownfield Development Rider Tariff. In March 2008, KU and LG&E received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU, for implementation within approximately eight months, for its large commercial and industrial customers.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave Virginia customers the ability to choose their electric supplier. Rates are capped at current levels through December 2010. In April 2007, Virginia passed legislation terminating this competitive market and commencing re-regulation of utility rates in Virginia. The new act will end the cap on rates at the end of 2008, rather than through December 2010, and end customer choice for most consumers in the applicable regions of the state. Thereafter, a hybrid model of regulation is expected to apply in Virginia, whereby utility rates would be reviewed every two years and a utility's rate of return on equity shall not be set lower than the average of the rates of return for other regional utilities, with certain caps, floors or adjustments. The legislation was effective in July 2007, and also includes a 10% nonbinding goal for renewable power generation by 2022, as well as incentives for new generation, including renewables. Under the legislation, KU retains an existing exemption from customer choice and other restructuring activities as applicable to KU's limited service territory in Virginia. However, subject to future developments, KU may or may not undertake such a rate proceeding in the first six months of 2009 based on calendar year 2008 financial data under the hybrid model of regulation, or make biennial rate filings with the Virginia Commission thereafter.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case are to present the proposed interconnection guidelines to the Kentucky Commission in September 2008.

Note 3 - Financial Instruments

Energy Trading and Risk Management Activities (non-hedging derivatives). KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at June 30, 2007, had a maturity of less than one year. There were no contracts outstanding at June 30, 2008. Energy trading and risk management contracts are valued using Level 2, prices actively quoted for proposed or executed transactions or quoted by brokers or observable inputs other than quoted prices.

Effective January 1, 2008, KU adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2.

Note 4 - Pension and Other Postretirement Benefit Plans

The following table provides the components of net periodic benefit cost for pension and other benefit plans:

	Three Months Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
(in millions)	2008	2007	2008	2007	2008	2007	2008	2007
Service cost	$ 1	$ 1	$ -	$ -	$ 3	$ 3	$ 1	$ 1
Interest cost	4	4	1	1	9	10	2	2
Expected return on plan assets	(4)	(5)	-	(1)	(10)	(12)	-	(1)
Amortization of prior service costs	-	1	-	-	-	1	-	-
Amortization of actuarial loss	-	-	-	-	-	1	-	-
Amortization of transitional obligation	-	-	-	1	-	-	-	1
Benefit cost	$ 1	$ 1	$ 1	$ 1	$ 2	$ 3	$ 3	$ 3

Net periodic benefit costs incurred by employees of KU are reflected in both utility plant on the balance sheets and in operating expense on the income statements. The above costs do not include allocations of net periodic benefit costs from affiliates whose employees provide services to KU.

The pension plans are funded in accordance with all applicable requirements of the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. In March 2008, KU made contributions to other postretirement benefit plans of approximately $1 million. KU anticipates making further voluntary contributions in 2008 to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the postretirement medical account under the pension plan up to the maximum amount allowed by law. See Note 9, Subsequent Events.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each tax period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. With few exceptions, KU is no longer subject to U.S. federal income tax examinations for years before 2004. Statutes of limitations related to 2004 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed.

KU adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million, and are based on the expiration of statutes during 2008.

The amount KU recognized as interest accrued related to unrecognized tax benefits in interest expense was less than $1 million at June 30, 2008 and December 31, 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, KU accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by KU upon adoption of FIN 48, or through June 30, 2008.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $10 million in each of the three–month periods ended June 30, 2008 and 2007, respectively, and $13 million and $20 million during the six months ended June 30, 2008 and 2007, respectively, decreasing current federal income taxes.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. KU is monitoring, but is not currently a party to, this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 – Short-Term and Long-Term Debt

KU's long-term debt includes $63 million classified as current liabilities ($30 million of which are currently being held by the Company as discussed below) because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County Series 2002 A and B, Muhlenberg County Series 2002 A and Mercer County Series 2002 A. These bonds mature in 2032. The repurchased bonds include the Carroll County 2006 Series C and Mercer County 2000 Series A bonds. KU does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the six months ended June 30, 2008, was 2.05%.

KU maintains a bilateral line of credit totaling $35 million which matures in June 2012. As of June 30, 2008, there was no balance outstanding under this facility.

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless KU defaults on the loan agreement. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets. At June 30, 2008, KU had no bond proceeds in trust, and at December 31, 2007, KU had $11 million of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At June 30, 2008, KU had an aggregate $333 million of outstanding pollution control indebtedness, of which $243 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" when there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the six months ended June 30, 2008 and 2007, the average rate on the auction rate bonds was 4.70% and 3.64%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first six months of 2008, the ratings of the Carroll County 2004 Series A bonds were downgraded from Aaa to A2 by Moody's and from AAA to AA, and subsequently to A and then to BBB+, by S&P, and the Carroll County 2006 Series C bonds were downgraded from Aaa to A2 by Moody's and from AAA to A-, and subsequently to BBB+, by S&P due to downgrades of the bond insurer. The ratings of the following bonds were downgraded from Aaa to Aa3 by Moody's and from AAA to AA by S&P due to downgrades of the bond insurer: Mercer County 2000 Series A, Carroll County 2002 Series C, Carroll County 2005 Series A and B, Carroll County 2006 Series A and B, Carroll County 2007 Series A and Trimble County 2007 Series A.

In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. These conversions were completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively.

In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bonds and the Mercer County 2000 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent.

In June 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2004 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, KU purchased the bonds from the remarketing agent. See Note 9, Subsequent Events.

As of June 30, 2008, KU had repurchased bonds in the amount of $30 million. KU will hold some or all of such repurchased bonds until a later date, at which time KU may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps KU has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructurings or redemption and refinancing, could result in KU incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
June 30, 2008	$400	$ 75	$325	2.43%
December 31, 2007	$400	$ 23	$377	4.75%

E.ON U.S. maintains a revolving credit facility totaling $311 million at June 30, 2008 and $150 million at December 31, 2007, to ensure funding availability for the money pool. The revolving facility as of June 30, 2008, is split into two separate loans totaling $311 million. One facility, totaling $150 million, is with E.ON North America, Inc., while the second, totaling $161 million, is with Fidelia; both are affiliated companies. The facility as of December 31, 2007, is with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
June 30, 2008	$311	$220	$ 91	3.17%
December 31, 2007	$150	$ 62	$ 88	4.97%

There were no redemptions of long-term debt year-to-date through June 30, 2008.

The issuance of long-term debt year-to-date through June 30, 2008, is summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Due to Fidelia	$75	5.85%	Unsecured	2023

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in KU's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of KU contained therein). See the above-referenced notes in KU's Annual Report regarding such commitments or contingencies.

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in this proceeding denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages. During 2005, the FERC declined KU's application to exercise exclusive jurisdiction on matters. In July 2005, the district court resolved a summary judgment motion made by KU in OMU's favor, ruling that a contractual provision grants OMU the ability to terminate the contract without cause upon four years' prior notice, for which ruling KU retains certain rights to appeal. A motion to reconsider that ruling is presently pending before the Court. In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding. The parties have generally completed discovery proceedings and have filed various dispositive motions which are before the court. Among other matters before the court on summary judgment and potentially subject to ruling before trial is a dispute involving differences in the calculation of approximately $16 million in facilities charges under the OMU agreement. The parties are conducting certain settlement discussions, in parallel, including potential mediation. A trial date has been set for October 2008. The Company is currently unable to determine the final outcome of this matter.

Construction Program. KU had approximately $280 million of commitments in connection with its construction program at June 30, 2008.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division for Air Quality in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the Kentucky Division for Air Quality issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling vacating the CAIR, which decision may be subject to rehearing or other subsequent proceedings. KU, LG&E and industry parties are monitoring these further proceedings. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. KU is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the current invalidation of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and KU's and LG&E's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The parties are currently evaluating the possibility of seeking review in the U.S. Supreme Court. Depending on the final outcome of the pending appeal, the CAMR could be superceded by new mercury reduction rules with different or more stringent requirements. Kentucky has subsequently proposed to repeal the corresponding state mercury regulations. At present, KU and LG&E are not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Companies' financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the final outcome of the challenge to CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2007 time period at a cost of $220 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $880 million during the 2008 through 2010 time period for pollution controls, including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the U.S. Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. The parties are currently proceeding with discovery while concurrently engaged in active settlement negotiations. A $3 million accrual has been recorded based on the current status of those discussions, however, KU cannot determine the overall outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result, which could be in excess of the amount reserved. Also of uncertain potential effect, if any, is the invalidation of the CAIR on the progress or content of settlement discussions. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. The Companies have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and ongoing claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 8 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2008	2007	2008	2007
Electric operating revenues from LG&E	$14	$ 8	$29	$26
Purchased power from LG&E	25	23	51	53

Interest Charges

See Note 6, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2008	2007	2008	2007
Interest on money pool loans	$ 0	$ 2	$ 1	$ 3
Interest on Fidelia loans	13	8	25	15

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to E.ON U.S. Services relate to cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2008	2007	2008	2007
E.ON U.S. Services billings to KU	$ 72	$210	$111	$380
KU billings to LG&E	14	8	37	22
LG&E billings to KU	4	23	5	33
KU billings to E.ON U.S. Services	1	33	2	35

In June 2008, LG&E transferred assets related to Trimble County Unit 2 with a net book value of $10 million to KU.

In March and June 2008, KU received capital contributions from its common shareholder, E.ON U.S., in the amounts of $25 million and $50 million, respectively.

Note 9 – Subsequent Events

On July 3, 2008, KU made contributions to other postretirement benefit plans of approximately $1 million.

On July 16, 2008, the Carroll County 2004 Series A bonds were converted from an auction rate mode to a weekly interest rate mode. In connection with the conversion, KU purchased the bonds from the remarketing agent.

On July 23, 2008, a cooling tower associated with KU's 510 Mw Ghent 2 generating unit suffered a partial structural collapse rendering such unit generally inoperable for an estimated three-week period. KU is analyzing various options and the costs thereof regarding replacement power for the temporary and permanent repair of such facilities, as well as effects on excess or wholesale power sales and purchases.

On July 25, 2008, KU borrowed $50 million from Fidelia for a period of 10 years at a fixed rate of 6.16%. The loan is unsecured.

On July 29, 2008, KU filed an application with the Kentucky Commission for an increase in base rates of approximately 2.0% or $22 million annually. KU has requested the increase based on the twelve month test year ended April 30, 2008. KU requested new base rates to become effective on and after September 1, 2008. In conjunction with filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. Under Kentucky Commission practice, new rates will most likely be suspended an additional five months with an effective date on and after February 1, 2009, subject to refund if an order is not issued by such time. The rate review proceeding, which will likely involve opposition filings by intervenors or other third-parties, should be completed in early 2009, subject to a number of factors.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during the three and six month periods ended June 30, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of December 31, 2007, KU provided electricity to approximately 506,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution of natural gas in Kentucky.

In July 2008, KU filed an application with the Kentucky Commission requesting increases in base electric rates of approximately 2.0% or $22 million annually. In conjunction with filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT and merger surcredit will result in a $16 million increase in revenues annually. These proceedings should be completed in early 2009.

Environmental Matters

Protection of the environment is a major priority for KU. Federal, state and local regulatory agencies have issued KU permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Three Months Ended June 30, 2008, Compared to Three Months Ended June 30, 2007

Net Income

Net income for the three months ended June 30, 2008, decreased $7 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($26 million) and increased interest expense ($3 million), partially offset by increased electric revenues ($15 million) and lower income taxes ($7 million).

Revenues

Revenues increased $15 million in the three months ended June 30, 2008, primarily due to:
- Increased ECR surcharge ($10 million) due to increased recoverable capital spending
- Increased wholesale sales ($9 million) due to increased volumes and increased wholesale market pricing
- Increased fuel costs ($7 million) billed to customers through the FAC due to increased fuel prices
- Increased demand side management cost recovery ($2 million) due to additional conservation programs
- Decreased sales volumes to native load ($13 million) due in part to a 31% decrease in cooling degree days

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $3 million in the three months ended June 30, 2008, primarily due to increased contract and spot market pricing for coal and natural gas due to increased transportation costs.

Power purchased expense increased $9 million in the three months ended June 30, 2008, primarily due to:
- Increased pricing on purchases ($7 million) and higher demand payments ($2 million)
- Increased volumes purchased ($2 million) related to intercompany purchases
- Decreased volumes purchased for native load ($2 million) due to increased internal generation

Other operation and maintenance expense increased $12 million in the three months ended June 30, 2008, primarily due to increased other operation expense ($8 million) and increased maintenance expense ($4 million).

Other operation expense increased $8 million in the three months ended June 30, 2008, primarily due to:
- Increased demand side management conservation expense ($2 million) due to additional conservation programs
- Increased contract labor and material costs for outages ($2 million)
- Increased outside services ($1 million) due to higher outside counsel expense
- Increased generation expense ($1 million) due to increased outages

- Increased 401k, medical insurance and FICA expense ($1 million)
- Increased research and development expense ($1 million)

Maintenance expense increased $4 million in the three months ended June 30, 2008, primarily due to:
- Increased electric and boiler maintenance ($3 million) due to higher cost of outside contractors and materials
- Increased steam plant maintenance ($1 million) due to increased generation and consumables prices

Interest expense, including interest expense to affiliated companies, increased $3 million in the three months ended June 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.3	3.9
Amortization of investment tax credits	(0.3)	(0.2)
EEI dividend	(6.2)	(3.2)
Other differences	(2.6)	(1.5)
Effective income tax rate	28.2%	34.0%

The effective income tax rate decreased for the three months ended June 30, 2008, compared to the three months ended June 30, 2007. State income taxes net of federal benefit decreased due to an increase in state coal credits. Also contributing to the lower effective rate were the tax benefits associated with increased dividends received from EEI.

Six Months Ended June 30, 2008 Compared to
Six Months Ended June 30, 2007

Net Income

Net income for the six months ended June 30, 2008, decreased $6 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($61 million) and increased interest expense ($8 million), partially offset by increased electric revenues ($50 million), lower income taxes ($10 million) and higher other income ($3 million).

Revenues

Revenues in the six months ended June 30, 2008, increased $50 million primarily due to:
- Increased ECR surcharge ($24 million) due to increased recoverable capital spending
- Increased fuel costs ($22 million) billed to customers through FAC due to increased fuel prices
- Increased wholesale sales ($7 million) due to increased wholesale market pricing
- Increased demand side management cost recovery ($2 million) due to additional conservation programs
- Decreased sales volumes delivered to native load ($5 million) resulting in part from a 34% decrease in cooling degree days

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $16 million in the six months ended June 30, 2008, primarily due to:

- Increased generation ($9 million) due to increased wholesale sales
- Increased contract and spot market pricing for coal and natural gas ($7 million) due to increased transportation costs

Power purchased expense increased $20 million in the six months ended June 30, 2008, primarily due to:

- Increased cost per mWh of purchases ($16 million) due to increased purchases and increased fuel prices
- Increased costs ($4 million) due to intercompany purchases

Other operation and maintenance expense increased $20 million in the six months ended June 30, 2008, primarily due to increased other operation expense ($7 million) and increased maintenance expense ($13 million).

Other operation expense increased $7 million in the six months ended June 30, 2008, primarily due to:

- Increased generation and transmission expense ($3 million) due to increased outages and transmission expense for native load
- Increased demand side management conservation expense ($2 million) due to additional conservation programs
- Increased outside services ($1 million) due to higher outside counsel expense
- Increased expense for uncollectible accounts ($1 million)

Maintenance expense increased $13 million in the six months ended June 30, 2008, primarily due to:

- Increased electric and boiler maintenance expense ($4 million) due to higher cost of outside contractors and materials
- Increased distribution expense ($3 million) due to increased storm restoration
- Increased overhead conductor and devices maintenance expense ($3 million)
- Increased overhead line and vegetation management expense ($2 million) due to increased storm restoration
- Increased maintenance supervision and engineering expense ($1 million) due to engineering consulting and testing costs for new projects in 2008

Interest expense, including interest expense to affiliated companies, increased $8 million in the six months ended June 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.8	3.8
Amortization of investment tax credits	(0.2)	(0.2)
EEI dividend	(4.6)	(2.8)
Other differences	(2.8)	(1.4)
Effective income tax rate	30.2%	34.4%

The effective income tax rate decreased for the six months ended June 30, 2008, compared to the six months ended June 30, 2007. State income taxes net of federal benefit decreased due to an increase in state coal credits. Also contributing to the lower effective rate were the tax benefits associated with increased dividends received from EEI.

Liquidity and Capital Resources

KU uses net cash generated from its operations and external financing (including financing from affiliates) to fund construction of plant and equipment and the payment of dividends. KU believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was $187 million and $147 million for the six months ended June 30, 2008 and 2007, respectively.

The 2008 increase of $40 million was primarily the result of increases in cash due to changes in:

- Prepayments and other current assets ($20 million) due to income tax deposits exceeding the liabilities accrued
- Accounts receivable ($20 million)
- FAC receivable, net ($15 million)
- Other ($14 million)
- Pension funding ($13 million) due to higher pension funding in 2007
- Other current liabilities ($1 million)

These increases were partially offset by cash provided by changes in:

- Accounts payable ($16 million)
- Earnings, net of non-cash items ($15 million)
- Materials and supplies ($12 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $360 million and $319 million in the six months ended June 30, 2008 and 2007, respectively. Net cash used for investing activities increased $17 million in the six months ended June 30, 2008, compared to 2007, primarily due to increased capital expenditures of $41 million and an asset transferred from an affiliate of $10 million. The change in restricted cash increased $34 million and represents the escrowed proceeds of the Pollution Control Bonds issued which were disbursed as qualifying costs were incurred.

Financing Activities

Net cash inflows from financing activities were $172 million and $195 million in the six months ended June 30, 2008 and 2007, respectively. Net cash provided by financing activities decreased $23 million in the six months ended June 30, 2008 compared to 2007, due to decreased long-term borrowings from affiliated company of $103 million, the issuance of pollution control bonds of $81 million in 2007 and the reacquisition of bonds in the amount of $30 million, partially offset by the retirement of first mortgage bonds of $107 million in 2007, increased additional paid-in capital of $75 million and increased short-term borrowings from affiliated company of $9 million.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

KU expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $1,465 million, consisting primarily of construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $425 million, construction of TC2 totaling approximately $360 million, the Brown ash pond totaling approximately $40 million, a customer care system totaling approximately $25 million and on-going construction related to generation and distribution assets.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

KU has a variety of funding alternatives available to meet its capital requirements. KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds of up to $400 million available to KU at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Note 6 of Notes to Financial Statements.

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See Note 7 of Notes to Financial Statements for current commitments. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Regulatory approvals are required for KU to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2007, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2009 allowing short-term borrowing of up to $400 million.

KU's debt ratings as of June 30, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework . The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company's internal control over financial reporting that occurred during the six months ended June 30, 2008, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

KU is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Legal Proceedings

For a description of the significant legal proceedings involving KU, reference is made to the information under the following captions of KU's Annual Report for the year ended December 31, 2007: Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in KU's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, KU believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

FINANCIAL STATEMENTS

SEPTEMBER 30, 2008

Kentucky Utilities Company

Financial Statements and Additional Information

As of September 30, 2008 and December 31, 2007
and for the three-month and nine-month periods ended
September 30, 2008 and 2007

INDEX OF ABBREVIATIONS

ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	Kentucky Utilities Company
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EUSIC	E.ON US Investments Corp.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation
GHG	Greenhouse Gas
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
kWh	Kilowatt Hours
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Units
Moody's	Moody's Investor Services, Inc.
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

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Financial Statements (Unaudited)

Kentucky Utilities Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
OPERATING REVENUES:				
Total operating revenues	$ 371	$ 345	$ 1,039	$ 963
OPERATING EXPENSES:				
Fuel for electric generation	147	138	380	354
Power purchased	54	39	164	129
Other operation and maintenance expenses	67	62	208	184
Depreciation and amortization	36	31	99	89
Total operating expenses	304	270	851	756
OPERATING INCOME	67	75	188	207
Other expense (income) – net	(13)	(7)	(31)	(23)
Interest expense (Notes 5 and 6)	3	3	10	11
Interest expense to affiliated companies (Note 8)	15	11	41	29
INCOME BEFORE INCOME TAXES	62	68	168	190
Federal and state income taxes (Note 5)	19	18	51	60
NET INCOME	$ 43	$ 50	$ 117	$ 130

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Balance at beginning of period	$ 1,111	$ 950	$ 1,037	$ 870
Net income	43	50	117	130
Balance at end of period	$ 1,154	$ 1,000	$ 1,154	$ 1,000

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	September 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 2	$ -
Restricted cash	1	11
Accounts receivable – less reserves of $3 million and $2 million as of September 30, 2008 and December 31, 2007, respectively	176	172
Accounts receivable from affiliated companies (Note 8)	8	17
Materials and supplies:		
Fuel (predominantly coal)	59	42
Other materials and supplies	36	34
Prepayments and other current assets	3	12
Total current assets	285	288
Other property and investments	33	29
Utility plant:		
At original cost	5,459	4,939
Less: reserve for depreciation	1,705	1,622
Net utility plant	3,754	3,317
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	28	28
Other	96	86
Cash surrender value of key man life insurance	38	37
Other assets	10	11
Total deferred debits and other assets	172	162
Total assets	$ 4,244	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	September 30, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 33	$ 33
Notes payable to affiliated companies (Notes 6 and 8)	116	23
Accounts payable	141	160
Accounts payable to affiliated companies (Note 8)	41	48
Customer deposits	20	20
Other current liabilities	31	28
Total current liabilities	382	312
Long-term debt:		
Long-term debt (Note 6)	220	300
Long-term debt to affiliated company (Notes 6 and 8)	1,106	931
Total long-term debt	1,326	1,231
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	284	285
Accumulated provision for pensions and related benefits (Note 4)	88	83
Investment tax credit (Note 5)	77	55
Asset retirement obligation	32	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	323	310
Deferred income taxes - net	17	22
Other	18	10
Other liabilities	20	23
Total deferred credits and other liabilities	859	818
Common equity:		
Common stock, without par value –		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital	215	90
Retained earnings	1,129	1,016
Undistributed subsidiary earnings	25	21
Total retained earnings	1,154	1,037
Total common equity	1,677	1,435
Total liabilities and equity	$ 4,244	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 117	$ 130
Items not requiring cash currently:		
Depreciation and amortization	99	89
Deferred income taxes – net	(3)	(2)
Investment tax credit – net	22	28
Other	2	2
Changes in current assets and liabilities:		
Accounts receivable	4	(1)
Material and supplies	(19)	15
Accounts payable	15	(22)
Prepayments and other current assets	-	9
Other current liabilities	4	(3)
Pension funding	(2)	(13)
Fuel adjustment clause receivable, net	4	(22)
Other	0	(1)
Net cash provided by operating activities	243	209
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(554)	(512)
Asset transferred from affiliate (Note 8)	(10)	-
Change in restricted cash	10	(17)
Net cash used for investing activities	(554)	(529)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirement of first mortgage bonds	-	(107)
Issuance of pollution control bonds	-	81
Additional paid-in capital	125	55
Long-term borrowings from affiliated company (Note 6)	175	278
Short-term borrowings from affiliated company – net (Note 6)	93	8
Reacquired bonds	(80)	-
Net cash provided by financing activities	313	315
CHANGE IN CASH AND CASH EQUIVALENTS	2	(5)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	-	6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2	$ 1

The accompanying notes are an integral part of these financial statements.

Note 1 - General

The unaudited financial statements include the accounts of the Company. KU's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted. These unaudited financial statements and notes should be read in conjunction with the Company's financial statements and additional information for the year ended December 31, 2007, including the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 was adopted effective January 1, 2008 and the Company elected not to fair value its eligible financial assets and liabilities.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments related to SFAS No. 157 have been evaluated and have no impact on the Company's financial statements. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives and AROs, as required, are now provided.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to KU's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in KU's Balance Sheets:

Kentucky Utilities Company
(unaudited)

(in millions)	September 30, 2008	December 31, 2007
ARO	$ 27	$ 24
Unamortized loss on bonds	12	10
MISO exit	19	20
FAC	14	17
ECR	19	11
Other	5	4
Subtotal	96	86
Pension and postretirement benefits	28	28
Total regulatory assets	$ 124	$ 114
Accumulated cost of removal of utility plant	$ 323	$ 310
Deferred income taxes – net	17	22
Other	18	10
Total regulatory liabilities	$ 358	$ 342

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. KU is seeking recovery of this asset with the Kentucky Commission as part of the current base rate case and will seek recovery of this asset in future proceedings with the Virginia Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. KU is seeking recovery of this asset with the Kentucky Commission as part of the current base rate case and will seek recovery of this asset in future proceedings with the Virginia Commission. KU currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit and deferred storm costs. Other regulatory liabilities include DSM and MISO costs currently included in base rates that will be netted against costs of withdrawing from the MISO in the next base rate case.

MISO Exit. KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, KU paid $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of $1 million and will provide an estimated $3 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in KU's base rate case, for which a hearing is scheduled for KU's Kentucky base rate case beginning on January 13, 2009. The Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In August 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period November 1, 2007 through April 30, 2008. A hearing was held on October 7, 2008. A second hearing has been scheduled for November 25, 2008, for the sole purpose of hearing public comments, if any, from several counties in which the newspapers failed to publish notice as requested in a timely manner. An order is expected in December of 2008 or first quarter of 2009.

In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in June 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The factor may be adjusted annually for over- or under-collections of fuel costs from the prior year. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kWh from the factor in effect for the April 2007 through March 2008 period.

ECR. In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of KU's environmental surcharge. The Kentucky Commission issued an Order in August 2008, approving the charges and credits billed through the ECR during the review period and the rate of return on capital.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Other Regulatory Matters

Hurricane Ike Wind Storm. In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through KU's service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $3 million of expenses related to the storm restoration. An order has been requested by the end of the year.

Base Rate Case. In July 2008, KU filed an application with the Kentucky Commission requesting increases in base electric rates of 2.0% or $22 million annually. A hearing is scheduled beginning on January 13, 2009. The requested rates have been suspended until February 5, 2009, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. In conjunction with the filing of the application for a change in base rates, based on previous orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT surcredit and merger surcredit will result in a $16 million increase in revenues annually.

FERC Wholesale Rate Case. In September 2008, KU filed an application with the FERC for increases in base electric rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requests a shift from current, all-in stated unit charge rates to an unbundled and formula rate. The revised rates represent an increase of 6% to 7% of current charges and requests a change from the all-in stated applicable return on equity of 12%. The proceeding involves data requests or hearings before the FERC, as well as data requests and filings by intervenors. An order in the proceeding may occur in early 2009.

CMRG and KCCS Contributions. In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and rate recovery will be considered in each company's next base rate case.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by KU and LG&E, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, KU, LG&E and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. KU and LG&E filed a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal, which motion has been opposed by the counter-parties.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. All rights of way for one transmission line have been acquired. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line, a Meade County, Kentucky court issued a ruling upholding the objections of two property co-owners and dismissed the condemnation proceeding pending the completion of the CCN appeal described above. KU and LG&E have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the condemnation litigation. Additional condemnation proceedings involving other parcels of property to support this transmission line are also pending in neighboring Hardin County where three landowners have challenged KU's and LG&E's right to easements, on the same grounds cited by the Meade County court and other purported bases, including asserted deficiencies in the air permit relating to the TC2 generation unit. In May, July and August 2008, the Hardin County Circuit Court issued rulings denying the property owners' various motions, finding that KU and LG&E had established their condemnation rights and granting judgment in favor of KU and LG&E. In August 2008, the property owners petitioned for intermediate relief to the Kentucky Court of Appeals and received a stay preventing KU and LG&E access to the properties. KU and LG&E have made responsive pleadings at the Court of Appeals and continue to engage in settlement negotiations with the property owners. In a separate, further proceeding, certain landowners have filed a lawsuit in federal court in Louisville, Kentucky against the U.S. Army, KU and LG&E alleging that the U.S. Army failed to comply with Section 106 of the National Historic Preservation Act in granting an easement across Fort Knox. KU and LG&E are working with the U.S. Army in defending against the claims. KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to these real property proceedings.

Merger Surcredit. In December 2007, KU submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008, to the Kentucky Commission. In June 2008, the Kentucky Commission issued an Order approving a settlement which provides for continuation of the merger surcredit until new base rates go into effect.

VDT. In accordance with the Kentucky Commission's Order dated March 24, 2006, the VDT surcredit terminated in the first billing month after the filing for a change in base rates. As KU filed its application with the Kentucky Commission for an increase in base rates in July 2008, the VDT surcredit terminated with the first billing cycle in August 2008.

DSM. In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. During May 2008, the SERC and KU agreed in principle to a settlement involving penalties totaling less than $1 million concerning KU's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. The SERC and KU are currently involved in settlement negotiations concerning a June 2008 self-report by KU relating to three other standards. Additionally, KU has submitted to the SERC an October 2008 self report of a possible violation relating to one further standard, for which SERC proceedings are in the early stages and therefore unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements in principle with the SERC proceed to the NERC and FERC review before becoming final. While KU believes itself to be in compliance with the mandatory reliability standards, KU cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission. In July 2008, KU filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. KU also filed the depreciation study with the Virginia Commission, but has not requested formal review and approval of the depreciation rates from the Virginia Commission. Such a review will take place either during KU's next base rate case in Virginia or when KU makes a formal application to the Virginia Commission for approval of the proposed rates.

Brownfield Development Rider Tariff. In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU, for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave Virginia customers the ability to choose their electric supplier. Rates are capped at current levels through December 2010. In April 2007, Virginia passed legislation terminating this competitive market and commencing re-regulation of utility rates in Virginia. The new act will end the cap on rates at the end of 2008, rather than through December 2010, and end customer choice for most consumers in the applicable regions of the state. Thereafter, a hybrid model of regulation is expected to apply in Virginia, whereby utility rates would be reviewed every two years and a utility's rate of return on equity shall not be set lower than the average of the rates of return for other regional utilities, with certain caps, floors or adjustments. The legislation was effective in July 2007, and also includes a 10% nonbinding goal for renewable power generation by 2022, as well as incentives for new generation, including renewables. Under the legislation, KU retains an existing exemption from customer choice and other restructuring activities as applicable to KU's limited service territory in Virginia. However, subject to future developments, KU may or may not undertake such a rate proceeding in the first six months of 2009 based on calendar year 2008 financial data under the hybrid model of regulation, or make biennial rate filings with the Virginia Commission thereafter.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented the proposed interconnection guidelines to the Kentucky Commission in October 2008. An order is expected by the end of the year.

Note 3 - Financial Instruments

Energy Trading and Risk Management Activities (non-hedging derivatives). KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at September 30, 2008 and 2007, had a maturity of less than one year. Energy trading and risk management contracts are valued using Level 2, prices actively quoted for proposed or executed transactions or quoted by brokers or observable inputs other than quoted prices. Collateral related to the energy trading and risk management contracts is categorized as restricted cash.

Effective January 1, 2008, KU adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. KU has classified the applicable financial assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157. The following table sets forth by level within the fair value hierarchy KU's financial assets that were accounted for at fair value on a recurring basis as of September 30, 2008. Liabilities accounted for at fair value total less than $1 million and use Level 2 measurements. There are no Level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1	Level 2	Total
Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Energy trading and risk management contracts cash collateral	1	-	1
Total Assets	$ 1	$ 1	$ 2

Note 4 - Pension and Other Postretirement Benefit Plans

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and E.ON U.S. Services employees who are providing services to the utility. The E.ON U.S. Services costs that are allocated to KU are approximately 43% and 42% of E.ON U.S. Services total cost for 2008 and 2007, respectively.

Pension Benefits

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service cost	$ 3	$ 3	$ 9	$ 11
Interest cost	10	10	31	30
Expected return on plan assets	(12)	(12)	(35)	(37)
Amortization of prior service costs	1	1	1	1
Amortization of actuarial loss	-	1	1	3
Benefit cost	$ 2	$ 3	$ 7	$ 8

Other Postretirement Benefits

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service cost	$ 1	$ 1	$ 1	$ 1
Interest cost	1	2	4	4
Expected return on plan assets	-	-	(1)	(1)
Amortization of transition costs	-	-	1	1
Benefit cost	$ 2	$ 3	$ 5	$ 5

During 2008, KU made contributions to other postretirement benefits plans of $2 million. KU anticipates making further voluntary contributions to the postretirement plan, but no additional contributions to the pension plan in 2008.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each tax period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. With few exceptions, KU is no longer subject to U.S. federal income tax examinations for years before 2005. Statutes of limitations related to 2005 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed.

KU adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million, and are based on the expiration of the audit periods as defined in the statutes.

The amount KU recognized as interest accrued related to unrecognized tax benefits in interest expense was less than $1 million as of September 30, 2008 and December 31, 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, KU accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by KU upon adoption of FIN 48, or through September 30, 2008.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $9 million and $10 million during the three-month periods ended September 30, 2008 and 2007, respectively, and $22 million and $30 million during the nine months ended September 30, 2008 and 2007, respectively, decreasing current federal income taxes.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. In August 2008, the plaintiffs submitted an amended complaint alleging additional claims for relief. KU is monitoring, but is not currently a party to, this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 – Short-Term and Long-Term Debt

KU's long-term debt includes $33 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County Series 2002 A and B, Muhlenberg County Series 2002 A and Mercer County Series 2002 A. These bonds mature in 2032. KU does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the nine months ended September 30, 2008, was 1.90%.

As of September 30, 2008, KU maintained a bilateral line of credit totaling $35 million which matures in June 2012. At that time, there was no balance outstanding under this facility. See Note 9 Subsequent Events.

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless KU defaults on the loan agreement. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) were held in trust pending expenditure for qualifying assets. At September 30, 2008, KU had no bond proceeds in trust, and at December 31, 2007, KU had $11 million of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At September 30, 2008, KU had an aggregate $333 million of outstanding pollution control indebtedness, of which $193 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" when there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the nine months ended September 30, 2008 and 2007, the average rate on the auction rate bonds was 4.72% and 3.29%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first nine months of 2008, the ratings of the Carroll County 2004 Series A bonds were downgraded from Aaa to A2 by Moody's and from AAA to AA, and subsequently to A and then to BBB+, by S&P, and the Carroll County 2006 Series C bonds were downgraded from Aaa to A2 by Moody's and from AAA to A-, and subsequently to BBB+, by S&P due to downgrades of the bond insurer. The ratings of the following bonds were downgraded from Aaa to Aa3 by Moody's and from AAA to AA by S&P due to downgrades of the bond insurer: Mercer County 2000 Series A, Carroll County 2002 Series C, Carroll County 2005 Series A and B, Carroll County 2006 Series A and B, Carroll County 2007 Series A and Trimble County 2007 Series A.

In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. These conversions were completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively.

In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bonds and the Mercer County 2000 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent.

In June 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2004 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, KU purchased the bonds from the remarketing agent.

As of September 30, 2008, KU had repurchased bonds in the amount of $80 million. KU will hold some or all of such repurchased bonds until a later date, at which time KU may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps KU has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructurings or redemption and refinancing, could result in KU incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2008	$400	$116	$284	2.45%
December 31, 2007	$400	$ 23	$377	4.75%

E.ON U.S. maintains a revolving credit facility totaling $489 million at September 30, 2008 and $150 million at December 31, 2007, to ensure funding availability for the money pool. The revolving facility as of September 30, 2008, is split into separate loans totaling $489 million. One facility, totaling $150 million, is with E.ON North America, Inc., while the remaining loans, totaling $339 million, are with Fidelia; both are affiliated companies. The facility as of December 31, 2007, is with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2008	$489	$469	$20	3.94%
December 31, 2007	$150	$ 62	$88	4.97%

There were no redemptions of long-term debt year-to-date through September 30, 2008.

The issuances of long-term debt year-to-date through September 30, 2008, are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Due to Fidelia	$50	6.16%	Unsecured	2018
2008	Due to Fidelia	$50	5.645%	Unsecured	2018
2008	Due to Fidelia	$75	5.85%	Unsecured	2023

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in KU's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of KU contained therein). See the above-referenced notes in KU's Annual Report regarding such commitments or contingencies.

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in this proceeding denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages.

During 2005, the FERC declined KU's application to exercise exclusive jurisdiction on matters. In July 2005, the district court resolved a summary judgment motion made by KU in OMU's favor, ruling that a contractual provision grants OMU the ability to terminate the contract without cause upon four years' prior notice. A motion to reconsider that ruling was later denied.

In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding, pursuant to the summary judgment in its favor. However, KU retains the right to appeal that summary judgment once the remaining claims in the lawsuit are adjudicated. The parties completed discovery and filed various dispositive motions before the court.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in KU's favor, including determinations that KU's interpretation of facilities charge fund payments was accurate; that KU is the proportionate owner of NOx allowances allocated to the OMU plant by the government; that OMU's claim for back-up power charges should be capped at a certain price and a denial of OMU's petition to dismiss KU's counterclaim. The summary judgment rulings dismiss a substantial portion of OMU's material claims. Following the trial or other qualifying procedural occurrence, the various summary judgment motions would become appealable. The trial began on October 21, 2008 on the remaining matters before the court, including KU's counterclaim that OMU has failed to operate and maintain its plant in a good and workmanlike manner. The parties retain certain appeal rights and the Company is currently unable to determine the final outcome of this matter.

Construction Program. KU had approximately $224 million of commitments in connection with its construction program at September 30, 2008.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ has 90 days to respond to the EPA's order. Although the Company does not expect material changes in the permit as a result of the petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, KU is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding statutory and regulatory infirmities in the CAIR and potentially vacating it, and has conducted subsequent proceedings on the matter. During October 2008, the appellate court issued a ruling requesting briefs of the parties regarding whether vacating the CAIR is the applicable relief to be granted. KU, LG&E and industry parties are monitoring these further proceedings. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. KU is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the current invalidation of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and KU's and LG&E's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. Certain parties have filed a petition seeking review in the U.S. Supreme Court. Depending on the final outcome of the pending appeal, the CAMR could be superseded by new mercury reduction rules with different or more stringent requirements. Kentucky has subsequently proposed to repeal the corresponding state mercury regulations. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Companies' financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the final outcome of the challenge to CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2007 time period at a cost of $220 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $520 million during the 2008 through 2010 time period for pollution controls, including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is also monitoring relevant regulatory proceedings involving the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the U.S. Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. The parties are currently proceeding with discovery while concurrently engaged in active settlement negotiations. A \$3 million accrual has been recorded based on the current status of those discussions, however, KU cannot determine the overall outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result, which could be in excess of the amount reserved. Also of uncertain potential effect, if any, is the invalidation of the CAIR on the progress or content of settlement discussions. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's

Ghent 2 generating unit. KU and LG&E have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 8 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2008	2007	2008	2007
Electric operating revenues from LG&E	$15	$ 7	$44	$33
Purchased power from LG&E	21	18	73	71

Interest Charges

See Note 6, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest expense was as follows:

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Interest on money pool loans	$ 1	$ 2	$ 1	$ 5
Interest on Fidelia loans	14	9	40	24

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to E.ON U.S. Services relate to cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU were as follows:

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
E.ON U.S. Services billings to KU	$62	$42	$173	$389
KU billings to LG&E	21	11	58	33
LG&E billings to KU	-	2	5	35
KU billings to E.ON U.S. Services	-	22	2	24

In June 2008, LG&E transferred assets related to Trimble County Unit 2 with a net book value of $10 million to KU.

In March, June and September 2008, KU received capital contributions from its common shareholder, E.ON U.S., in the amounts of $25 million, $50 million and $50 million, respectively.

Note 9 – Subsequent Events

On October 17, 2008, KU closed on a new $78 million bilateral line of credit which has a 364 day maturity.

On October 17, 2008, KU issued Carroll County 2008 Series A tax exempt bonds in the amount of $78 million. The new bonds mature on February 1, 2032, and bear interest at a variable rate. The new bonds refinance four existing Series F bonds (Carroll County 2005 Series A and C - $13 million each and the Carroll County 2006 Series A and C - $17 million each), and includes $18 million of new funding. The proceeds from the new funding will be held in escrow pending incurrence of qualifying expenditures.

On October 27, 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $3 million of expenses related to the Hurricane Ike wind storm restoration. An order has been requested by the end of the year.

On October 30, 2008, the Kentucky Commission issued an Order approving the establishment of regulatory assets for the Companies' contributions to the CMRG and KCCS. Rate recovery will be considered in each company's next base rate case.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during the three and nine month periods ended September 30, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of September 30, 2008, KU provided electricity to approximately 507,000 customers in 77 counties in central, southeastern and western Kentucky, approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution of natural gas in Kentucky.

In July 2008, KU filed an application with the Kentucky Commission requesting increases in base electric rates of approximately 2.0% or $22 million annually. In conjunction with the filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT surcredit and merger surcredit will result in a $16 million increase in revenues annually. A hearing for the Kentucky base rate case is scheduled beginning on January 13, 2009. The requested rates have been suspended until February 5, 2009, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding.

In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through KU's service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $3 million of expenses related to the storm restoration. An order has been requested by the end of the year.

Environmental Matters

Protection of the environment is a major priority for KU. Federal, state and local regulatory agencies have issued KU permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Three Months Ended September 30, 2008, Compared to Three Months Ended September 30, 2007

Net Income

Net income for the three months ended September 30, 2008, decreased $7 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($34 million), increased interest expense ($4 million) and increased income taxes ($1 million), partially offset by increased electric revenues ($26 million) and other income ($6 million).

Revenues

Revenues increased $26 million in the three months ended September 30, 2008, primarily due to:
- Increased fuel costs billed to customers through the FAC ($23 million) due to increased fuel prices
- Increased wholesale sales ($12 million) due to increased intercompany volumes, increased wholesale market pricing and increased volume due to decreased native load
- Increased ECR surcharge ($8 million) due to increased recoverable capital spending
- Increased demand charges ($5 million) due to higher peak load
- Decreased sales volumes to native load ($24 million) due in part to a 19% decrease in cooling degree days and outages related to damage from the Hurricane Ike wind storm

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $9 million in the three months ended September 30, 2008, primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($14 million)
- Decreased generation ($5 million) due to decreased native load

Power purchased expense increased $15 million in the three months ended September 30, 2008, primarily due to:

- Increased pricing and volumes on purchases for native load ($9 million) due to increased coal and gas costs and unit outages
- Increased intercompany volumes purchased ($4 million) due to lower native load requirements for LG&E as a result of milder weather, lower industrial sales and power outages from the Hurricane Ike wind storm, resulting in the purchase of excess power from LG&E
- Increased demand payments ($1 million) due to a new capacity contract

Other operation and maintenance expense increased $5 million in the three months ended September 30, 2008, due to increased maintenance expense ($3 million) and increased other operation expense ($2 million).

Maintenance expense increased $3 million in the three months ended September 30, 2008, primarily due to:

- Increased electric maintenance ($1 million) due to higher cost of outside contractors and materials
- Increased distribution maintenance ($1 million) due to the Hurricane Ike wind storm
- Increased cost for other indirect maintenance ($1 million) due to increased software maintenance lease cost

Other operation expense increased $2 million in the three months ended September 30, 2008, primarily due to increased outside services due to increased legal expenses as a result of ongoing litigation, mainly with OMU.

Interest expense, including interest expense to affiliated companies, increased $4 million in the three months ended September 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.8	3.1
Reduction of income tax reserve	(0.8)	(0.7)
Amortization of investment tax credits	(0.2)	(0.1)
Dividends received deduction related to EEI Investment	(3.9)	(2.5)
Other differences	(2.3)	(8.3)
Effective income tax rate	30.6%	26.5%

The effective income tax rate increased for the three months ended September 30, 2008, compared to the three months ended September 30, 2007 due primarily to the tax benefits resulting from income tax estimates recorded in 2006 being adjusted to the actual income tax return filed, which is included in the other differences, in the three months ended September 30, 2007. This was partially offset by decreased state income taxes net of federal benefit due to an increase in state coal credits and an increase in tax benefits associated with increased dividends received from EEI.

Nine Months Ended September 30, 2008 Compared to
Nine Months Ended September 30, 2007

Net Income

Net income for the nine months ended September 30, 2008, decreased $13 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($95 million) and increased interest expense ($11 million), partially offset by increased electric revenues ($76 million), lower income taxes ($9 million) and higher other income ($8 million).

Revenues

Revenues in the nine months ended September 30, 2008, increased $76 million primarily due to:

- Increased fuel costs billed to customers through the FAC ($85 million) due to increased fuel prices
- Increased wholesale sales ($19 million) due to increased wholesale market pricing and increased volume due to decreased native load
- Decreased sales volumes delivered to native load ($28 million) due in part to a 24% decrease in cooling degree days

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $26 million in the nine months ended September 30, 2008, primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($21 million)
- Increased generation ($5 million) due to increased wholesale sales

Power purchased expense increased $35 million in the nine months ended September 30, 2008, primarily due to:

- Increased pricing and volumes on purchases for native load ($28 million) due to increased coal and gas costs and unit outages
- Increased intercompany costs ($4 million) due to higher fuel costs
- Increased demand payments ($2 million) due to a capacity contract
- Increased wholesale purchase cost ($1 million) due to increased volumes and prices

Other operation and maintenance expense increased $24 million in the nine months ended September 30, 2008, due to increased maintenance expense ($13 million) and increased other operation expense ($11 million).

Maintenance expense increased $13 million in the nine months ended September 30, 2008, primarily due to:

- Increased electric and boiler maintenance expense ($5 million) due to higher cost of outside contractors and materials
- Increased overhead conductor and devices maintenance expense ($4 million) due to the Hurricane Ike wind storm and other storm restoration earlier in the year
- Increased steam maintenance expense ($2 million) due to high energy piping inspections and repairs
- Increased cost for other indirect maintenance ($2 million) due to increased software maintenance lease cost

Other operation expense increased $11 million in the nine months ended September 30, 2008, primarily due to:

- Increased generation expense due to increased unit outages and increased transmission expense to cover native load demand ($4 million)
- Increased outside services ($3 million) due to increased legal expenses as a result of ongoing litigation, mainly with OMU
- Increased expense for uncollectible accounts ($2 million)
- Increased cost of consumables ($1 million) primarily due to increased contract pricing
- Increased distribution expense ($1 million) due to the Hurricane Ike wind storm and other storm restoration earlier in the year

Interest expense, including interest expense to affiliated companies, increased $11 million in the nine months ended September 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.8	3.3
Reduction of income tax reserve	(0.3)	(0.3)
Amortization of investment tax credits	(0.1)	(0.2)
Dividends received deduction related to EEI investment	(4.3)	(2.7)
Other differences	(2.7)	(3.5)
Effective income tax rate	30.4%	31.6%

The effective income tax rate decreased for the nine months ended September 30, 2008, compared to the nine months ended September 30, 2007. State income taxes net of federal benefit decreased due to an increase in state coal credits. Also contributing to the lower effective rate were the tax benefits associated with increased dividends received from EEI.

Liquidity and Capital Resources

KU uses net cash generated from its operations, external financing (including financing from affiliates) and/or infusions of capital from its parent mainly to fund construction of plant and equipment. KU currently has a working capital deficiency of $97 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $80 million. These bonds are being held until they can be refinanced or restructured. See Notes 6 and 9 of Notes to Financial Statements. KU believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was $243 million and $209 million for the nine months ended September 30, 2008 and 2007, respectively.

The 2008 increase of $34 million was primarily the result of increases in cash due to changes in:

- Accounts payable ($37 million)
- FAC receivable, net ($26 million)
- Pension funding ($11 million) due to higher pension funding in 2007
- Other current liabilities ($7 million)
- Accounts receivable ($5 million)
- Other ($1 million)

These increases were partially offset by cash provided by changes in:

- Materials and supplies ($34 million)
- Earnings, net of non-cash items ($10 million)
- Prepayments and other current assets ($9 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $554 million and $512 million in the nine months ended September 30, 2008 and 2007, respectively. Net cash used for investing activities increased $25 million in the nine months ended September 30, 2008, compared to 2007, primarily due to increased capital expenditures of $42 million and an asset transferred from LG&E of $10 million. The increase in restricted cash of $27 million represents the escrowed proceeds of the pollution control bonds issued, which were disbursed as qualifying costs were incurred.

Financing Activities

Net cash inflows from financing activities were $313 million and $315 million in the nine months ended September 30, 2008 and 2007, respectively. Net cash provided by financing activities decreased $2 million in the nine months ended September 30, 2008 compared to 2007, due to decreased long-term borrowings from an affiliated company of $103 million, the issuance of pollution control bonds of $81 million in 2007 and the reacquisition of bonds in the amount of $80 million, partially offset by the retirement of first mortgage bonds of $107 million in 2007, increased short-term borrowings from an affiliated company of $85 million and increased infusions from E.ON U.S. of $70 million.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $1,465 million, consisting primarily of construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $425 million, construction of TC2 totaling approximately $360 million, the Brown ash pond totaling approximately $40 million, a customer care system totaling approximately $25 million and on-going construction related to generation and distribution assets.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

KU has a variety of funding alternatives available to meet its capital requirements. KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds of up to $400 million available to KU at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Note 6 of Notes to Financial Statements.

Regulatory approvals are required for KU to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2007, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2009 allowing short-term borrowing of up to $400 million.

KU's debt ratings as of September 30, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework . The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company’s internal control over financial reporting that occurred during the nine months ended September 30, 2008, that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

KU is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Legal Proceedings

For a description of the significant legal proceedings involving KU, reference is made to the information under the following captions of KU's Financial Statements and Additional Information for the year ended December 31, 2007 (the "Annual Report"): Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in KU's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, KU believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

FINANCIAL STATEMENTS

DECEMBER 31, 2008

Kentucky Utilities Company

Financial Statements and Additional Information

As of and For the Years Ended December 31, 2008 and 2007

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INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	KU
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation No.
GHG	Greenhouse Gas
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy LLC (now E.ON U.S. LLC)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PCB	Polychlorinated Biphenyl

PJM	PJM Interconnection
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

Business

GENERAL

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 508,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. Approximately 99% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky.

OPERATIONS

The sources of operating revenues and volumes of sales for the years ended December 31, 2008 and 2007, were as follows:

	2008		2007	
	Revenues (millions)	Volumes (Gwh)	Revenues (millions)	Volumes (Gwh)
Residential	$ 462	6,803	$ 430	6,847
Industrial & Commercial	636	10,709	597	11,047
Municipals	92	1,971	90	2,058
Other Retail	108	1,707	98	1,691
Wholesale	106	2,894	58	1,582
Total	$ 1,404	24,084	$ 1,273	23,225

KU's peak load was 4,476 Mw on January 25, 2008, when the temperature reached a low of 5 degrees Fahrenheit in Lexington, which was a new record.

The Company's power generating system includes coal-fired units operated at its four steam generating stations. Natural gas and oil fueled CTs supplement the system during peak or emergency periods. As of December 31, 2008, KU owned and operated the following generating stations while maintaining a 13%-15% reserve margin:

	Summer Capability Rating (Mw)
Steam Stations:	
Tyrone – Woodford County, KY	71
Green River – Muhlenberg County, KY	163
E.W. Brown – Mercer County, KY	697
Ghent – Carroll County, KY	1,918
Total Steam Stations	2,849
Dix Dam Hydroelectric Station – Mercer County, KY	24
CT Generators (Peaking capability):	
E.W. Brown – Mercer County, KY*	757
Haefling – Fayette County, KY	36
Paddy's Run – Jefferson County, KY *	74
Trimble County – Trimble County, KY *	632
Total CT Generators	1,499
Total Capability Rating	4,372

* Some of these units are jointly owned with LG&E. See Note 10 of Notes to Financial Statements for information regarding jointly owned units.

At December 31, 2008, KU's transmission system included 113 substations (39 of which are shared with the distribution system) with a total capacity of approximately 17,700 MVA and approximately 4,040 miles of lines. The distribution system included 483 substations (39 of which are shared with the transmission system) with a total capacity of approximately 6,865 MVA, 14,133 miles of overhead lines and 2,151 miles of underground conduit.

KU has a purchase power agreement with OMU, owns 20% of EEI's common stock and owns 2.5% of OVEC's common stock. Additional information regarding these relationships is provided in Notes 1 and 9 of Notes to Financial Statements.

KU has contracts with the Tennessee Valley Authority to act as its transmission reliability coordinator and Southwest Power Pool, Inc. to function as its independent transmission operator, pursuant to FERC requirements. See Note 2 of Notes to Financial Statements.

RATES AND REGULATIONS

E.ON, KU's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

In February 2007, KU completed a series of financial transactions that allowed it to cease periodic reporting under the Securities Exchange Act of 1934. See Note 7 of Notes to Financial Statements.

The Company is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. Given its competitive position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of SFAS No. 71.

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in base electric rates. In conjunction with the filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008. In January 2009, KU, the AG, KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's base electric rates will decrease by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated. (See Notes 2 and 12 of Notes to Financial Statements)

In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through the service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to the wind storm.

In January 2009, a significant winter ice storm passed through KU's service territory causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. KU currently estimates costs incurred of $66 million of expenses and $28 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

For a further discussion of regulatory matters, see Notes 2 and 9 of Notes to Financial Statements.

COAL SUPPLY

Coal-fired generating units provided approximately 99% of KU's net Kwh generation for 2008. The remaining net generation for 2008 was provided by natural gas and oil fueled CT peaking units and a hydroelectric plant. Coal is expected to be the predominant fuel used by KU in the foreseeable future, with natural gas and oil being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected from time to time by a number of factors including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

KU has entered into coal supply agreements with various suppliers for coal deliveries for 2009 and beyond and normally augments its coal supply agreements with spot market purchases. The Company has a coal inventory policy which it believes provides adequate protection under most contingencies.

KU expects to continue purchasing most of its coal, which has sulfur content in the 0.7% - 3.5% range, from western and eastern Kentucky, West Virginia, southern Indiana, southern Illinois and Ohio for the foreseeable future. With the installation of FGDs (SO_2 removal systems), KU expects its use of higher sulfur coal to increase. Coal is delivered to KU generating stations by a mix of transportation modes, including barge, truck and rail.

ENVIRONMENTAL MATTERS

Protection of the environment is a major priority for KU. Federal, state and local regulatory agencies have issued the Company permits for various activities subject to air quality, water quality and waste management laws and regulations. KU is also subject to extensive existing or potential environmental regulation. See Note 9 of Notes to Financial Statements for additional information.

STATE ENERGY POLICY

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet
- Increase Kentucky's use of renewable energy
- Sustainably grow Kentucky's production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase gas supplies, including coal-to-gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

Legislative and regulatory actions as a result of these proposals and their impact on KU, which may be significant, cannot currently be predicted.

COMPETITION

At this time, neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of the ultimate legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted. Virginia, formerly a deregulated jurisdiction, has enacted legislation which implements a hybrid model of cost-based regulation. See Note 2 of Notes to Financial Statements for additional information.

EMPLOYEES AND LABOR RELATIONS

KU had 977 full-time regular employees at December 31, 2008, 153 of which were operating, maintenance and construction employees represented by the IBEW Local 2100 and the United Steelworkers of America ("USWA") Local 9447-01. Effective August 1, 2006, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. Wage re-openers were negotiated and agreed to in July 2007 and July 2008. The Company and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers.

OFFICERS OF THE COMPANY

At December 31, 2008:

Name	Age	Position	Effective Date of Election to Present Position
Victor A. Staffieri	53	Chairman of the Board, President and Chief Executive Officer	May 2001
John R. McCall	65	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994
S. Bradford Rives	50	Chief Financial Officer	September 2003
Chris Hermann	61	Senior Vice President – Energy Delivery	February 2003
Paula H. Pottinger	51	Senior Vice President – Human Resources	January 2006
Paul W. Thompson	51	Senior Vice President – Energy Services	June 2000
Wendy C. Welsh	54	Senior Vice President – Information Technology	December 2000
Michael S. Beer	50	Vice President – Federal Regulation and Policy	September 2004
Lonnie E. Bellar	44	Vice President – State Regulation and Rates	August 2007
Kent W. Blake	42	Vice President – Corporate Planning and Development	August 2007
D. Ralph Bowling	51	Vice President – Power Production	June 2008
Laura G. Douglas	59	Vice President – Corporate Responsibility and Community Affairs	November 2007
R. W. Chip Keeling	52	Vice President – Communications	March 2002
John P. Malloy	47	Vice President – Energy Delivery – Retail Business	April 2007
Dorothy E. O'Brien	55	Vice President and Deputy General Counsel – Legal and Environmental Affairs	October 2007
George R. Siemens	59	Vice President – External Affairs	January 2001
David S. Sinclair	47	Vice President – Energy Marketing	January 2008
P. Greg Thomas	52	Vice President – Energy Delivery – Distribution Operations	April 2007
John N. Voyles, Jr.	54	Vice President – Transmission & Generation Services	June 2008
Daniel K. Arbough	47	Treasurer	December 2000
Valerie L. Scott	52	Controller	January 2005

Officers generally serve in the same capacities at KU and its affiliates, E.ON U.S. and LG&E.

Risk Factors

KU is subject to a number of risks, including without limitation, those listed below and elsewhere in this document. Such risks could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by KU.

The rates that KU charges customers, as well as other aspects of the business, are subject to significant and complex governmental regulation. Federal and state entities regulate many aspects of utility operations, including financial and capital structure matters; siting and construction of facilities; rates, terms and conditions of service and operations; mandatory reliability and safety standards; accounting and cost allocation methodologies; tax matters; acquisition and disposal of utility assets and securities and other matters. Such regulations may subject KU to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge KU's rate request and ultimately reduce, alter or limit the rates KU seeks.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues. The resulting changes to transmission and wholesale power market structures and prices are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which KU participates.

Transmission and interstate market activities of KU, as well as other aspects of the business, are subject to significant FERC regulation. KU's business is subject to extensive regulation under the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of KU.

KU undertakes significant capital projects and is subject to unforeseen costs, delays or failures in such projects, as well as risk of full recovery of such costs. The completion of these facilities without delays or cost overruns is subject to risks in many areas, including approval and licensing; permitting; land acquisition; construction problems or delays; increases in commodity prices or labor rates; contractor performance; weather and geological issues; and political, labor and regulatory developments.

KU's costs of compliance with environmental laws are significant and are subject to continuing changes. Extensive federal, state and local environmental regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions.

KU's operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters. These weather or man-made factors can significantly affect KU's finances or operations by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets or impacting future growth.

KU is subject to risks regarding potential developments concerning global climate change matters. Such developments could include potential federal or state legislation or industry initiatives limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. KU's generation fleet is predominantly coal-fired and may be highly impacted by developments in this area.

KU's business is subject to risks associated with local, national and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption and slower customer growth, which may adversely affect KU's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and KU's ability to raise capital. A deterioration of economic conditions may lead to decreased production by KU's industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

KU's business is concentrated in the Midwest United States, specifically Kentucky. Local and regional economic conditions, such as population growth, industrial growth or expansion and economic development, as well as the operational or financial performance of major industries or customers, can affect the demand for energy. Significant activities in KU's service territory include automotive; aluminum and steel smelting and fabrication; chemical processing; coal, mineral and ceramic-related activities; educational institutions; health care facilities; paper and pulp processing and water utilities.

KU is subject to operational risks relating to its generating plants, transmission facilities and distribution equipment. Operation of power plants and transmission and distribution facilities subjects KU to many risks, including the breakdown or failure of equipment; accidents; labor disputes; delivery/transportation problems; disruptions of fuel supply and performance below expected levels.

KU could be negatively affected by rising interest rates, downgrades to company or bond insurer credit ratings that could impact the Company's bond credit ratings or other negative developments in its ability to access capital markets. In the ordinary course of business, KU is reliant upon adequate long-term and short-term financing means to fund its significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, KU is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs to KU.

KU is subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business. General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to KU.

KU is subject to risks associated with defined benefit retirement plans, health care plans, wages

and other employee-related matters. Risks include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. The Company is also subject to risk related to changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

KU is subject to risks associated with federal and state tax regulations. Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact KU's results of operations. KU is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. KU also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which KU operates, various tax and fee increases may be proposed or considered. KU cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on KU's results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including base rate increase proceedings, TC2 proceedings, Kentucky Commission, FERC proceedings and other rates or regulatory matters affecting KU, see Notes 2 and 9 of Notes to Financial Statements.

Environmental

For a discussion of environmental matters including additional reductions in SO_2, NOx and other emissions mandated by recent or potential regulations; items regarding notices of violations and other emissions proceedings; global warming or climate change matters and other environmental items affecting KU, see Note 9 of Notes to Financial Statements.

Litigation

For a discussion of litigation matters, see Note 9 of Notes to Financial Statements.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, the Company believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

Selected Financial Data

(in millions)	Years Ended December 31 2008	2007	2006	2005	2004
Operating revenues	$ 1,404	$ 1,273	$ 1,210	$ 1,207	$ 995
Net operating income	$ 259	$ 268	$ 235	$ 202	$ 228
Net income	$ 158	$ 167	$ 152	$ 112	$ 134
Total assets	$ 4,508	$ 3,796	$ 3,148	$ 2,756	$ 2,610
Long-term obligations (including amounts due within one year)	$ 1,532	$ 1,264	$ 843	$ 746	$ 726

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during 2008 and 2007 and should be read in connection with the financial statements and notes thereto.

Forward Looking Statements

Some of the following discussion may contain forward-looking statements that are subject to risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may materially vary. Factors that could cause actual results to materially differ include, but are not limited to: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; actions by credit rating agencies and other factors described from time to time in KU's reports, including those noted in the Risk Factors section of this report.

RESULTS OF OPERATIONS

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Net Income

Net income in 2008 decreased $9 million compared to 2007. The decrease was primarily the result of increased operating expenses ($140 million) and increased interest expense ($16 million), partially offset by increased operating revenues ($131 million), decreased income taxes ($9 million), increased equity in earnings ($4 million) and increased other income – net ($3 million).

Revenues

Revenues in 2008 increased $131 million primarily due to:

- Increased fuel costs billed to customers through the FAC ($52 million) due to increased fuel prices
- Increased wholesale sales ($46 million) due to higher sales volumes and prices. Volumes increased to LG&E ($34 million) and third-parties ($10 million) as a result of excess generation made available by LG&E via a mutual agreement. KU sells its higher cost electricity to LG&E for its wholesale sales and KU purchases LG&E's lower cost electricity to serve its native load. Both KU and LG&E experienced lower native load requirements due to milder weather, the weakening economy and increased generation due to fewer scheduled coal-fired generation unit outages during 2008, resulting in higher volumes available for wholesale sales. Pricing to third-parties increased as a result of higher fuel costs ($2 million).
- Increased ECR surcharge ($43 million) due to increased recoverable capital spending
- Increased DSM cost recovery ($2 million) due to additional conservation programs
- Increased transmission sales ($2 million) due to higher sales to LG&E
- Decreased merger surcredit ($2 million) due to a lower rate approved by the Kentucky Commission in June 2008
- Decreased VDT surcredit ($1 million) due to its termination in August 2008
- Decreased retail sales volumes delivered ($17 million) due to 26% decrease in cooling degree days and weakening economic conditions

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $52 million in 2008 primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($39 million)
- Increased generation ($13 million) due to increased utilization of coal-fired generation units as a result of fewer scheduled outages in 2008

Power purchased expense increased $53 million in 2008 primarily due to:

- Increased prices for purchases used to serve retail customers ($24 million) due to higher market prices, influenced by higher fuel costs
- Increased power purchased from LG&E via a mutual agreement due to higher volumes ($8 million) and higher prices ($8 million). KU purchases LG&E's lower cost electricity to serve its native load ($16 million). LG&E was able to provide higher volumes due to its reduced native load requirements as a result of milder weather and the weakening economy.
- Increased third-party power purchase volume for native load ($5 million) due to increased unscheduled coal-fired generation unit outages
- Increased demand payments ($7 million) for energy purchased on a long term contract
- Increased expenses ($1 million) due to activities in the PJM market for the entire year of 2008 compared to only one quarter in 2007

Other operation and maintenance expenses increased $20 million in 2008 primarily due to increased other operation expenses ($16 million) and increased maintenance expenses ($4 million).

Other operation expenses increased $16 million in 2008 primarily due to:

- Increased outside services ($4 million) due to increased legal expenses as a result of on-going litigation, mainly with OMU
- Increased cost of consumables ($4 million) due to contract pricing and commissioning and start up costs of FGDs
- Increased transmission expense ($2 million) due to increased native load purchases from LG&E and the additional costs to comply with growing SERC and NERC Mandatory Reliability Standards
- Increased distribution expense ($2 million) due to storm restoration
- Increased uncollectible accounts ($2 million) due to the weakening economy
- Increased property taxes ($2 million) due to net decrease in expense in 2007 as a result of the application of coal tax credits

Other maintenance expenses increased $4 million in 2008 primarily due to increased maintenance of overhead conductors and devices ($4 million) resulting from storm restoration.

Equity earnings in EEI increased $4 million in 2008 primarily due to an increased average price per Mwh sold in 2008 over the price for 2007.

Other income – net increased $3 million in 2008 primarily due to:

- Increased $3 million due to allowance for funds used during construction related to several large multi-year projects
- Increased $1 million due to net losses on the sale of property in 2007

- Decreased $1 million due to settlement for Brown Station new source review litigation and related programs

Interest expense increased $16 million in 2008 primarily due to increased interest expense to affiliated companies ($17 million) due to additional debt, partially offset by decreased interest expense ($1 million) due to interest received on reacquired debt.

CRITICAL ACCOUNTING POLICIES/ESTIMATES

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. Specific risks for these critical accounting policies are described in the Notes to Financial Statements. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Events rarely develop exactly as forecasted and the best estimates routinely require adjustment.

Critical accounting policies and estimates including unbilled revenue, allowance for doubtful accounts, regulatory mechanisms, pension and postretirement benefits and income taxes are detailed in Notes 1, 2, 5, 6 and 9 of Notes to Financial Statements.

Recent Accounting Pronouncements. Recent accounting pronouncements affecting KU are detailed in Note 1 of Notes to Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

KU uses net cash generated from its operations, external financing (including financing from affiliates) and/or infusions of capital from its parent mainly to fund construction of plant and equipment. As of December 31, 2008, KU had a working capital deficiency of $183 million, primarily due to the terms of certain tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term debt. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. See Note 7 of Notes to Financial Statements. KU believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

E.ON U.S. sponsors pension and postretirement benefit plans for its employees. The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The market value of the combined investments within the plans declined by approximately 29% for the year ended December 31, 2008 due to the recent volatility in the capital markets. The benefit plan assets and obligations of E.ON U.S. and KU are remeasured annually using a December 31 measurement date. Investment losses resulted in an increase to the plans' unfunded status upon actuarial revaluation of the plans. Changes in the value of plan assets did not impact the income statement for 2008; however, reduced benefit plan assets will result in increased benefit costs in future years and may increase the amount, and accelerate the timing of, required future funding contributions. The Company anticipates its 2009 pension cost will be approximately $20 million higher than 2008. The amount of future funding will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The amount of such contributions cannot be determined at this time.

Operating Activities

The 2008 net decrease in cash provided by operations was $10 million and was primarily the result of decreases in cash due to changes in:

- Materials and supplies ($55 million) primarily due to increased fuel inventory volumes and higher fuel costs
- Earnings, net of non-cash items ($15 million)
- Other ($10 million) primarily due to changes in utility plant and customer advances for construction
- Environmental cost recovery receivable ($8 million) due to increased recoverable capital spending
- Prepayment and other current assets ($2 million)
- Wind storm regulatory asset ($2 million) due to new regulatory asset for Hurricane Ike restoration expenses
- Property and other taxes payable ($1 million)

These decreases were partially offset by cash provided by changes in:

- Accounts receivable ($28 million) due to timing of payments received from IMEA and IMPA
- Accounts payable ($24 million) primarily due to construction accruals related to FGD projects and TC2
- Pension and postretirement funding ($14 million) due to contributions made in 2007
- Fuel adjustment clause receivable, net ($13 million) due to timing of collections
- Other current liabilities ($2 million)
- Accrued income taxes ($2 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Net cash used for investing activities decreased $33 million in 2008 compared to 2007 primarily due to decreased capital expenditures of $55 million, partially offset by decreased restricted cash of $11 million, an asset transferred from LG&E of $10 million and decreased non-hedging derivative liability of $1 million. Restricted cash represents the escrowed proceeds of the pollution control bonds, which are disbursed as qualifying costs are incurred.

Financing Activities

Net cash provided by financing activities decreased $15 million due to decreased long-term borrowings from affiliated company of $198 million, reacquisition of bonds of $80 million, retirement of pollution control bonds of $60 million and issuance of pollution control bonds of $1 million, partially offset by the retirement of first mortgage bonds of $107 million in 2007, increased infusions from E.ON U.S. of $70 million, decreased repayment of short-term borrowings from affiliate – net of $67 million, reissuance of reacquired bonds of $63 million and retirement of reacquired bonds of $17 million.

See Note 7 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU expects its capital expenditures for the three-year period ending December 31, 2011 to total approximately $1,325 million, consisting primarily of construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $360 million, on-going construction related to distribution assets totaling approximately $250 million, on-going construction related to generation assets totaling approximately $220 million, ash pond and landfill projects totaling approximately $185 million, construction of TC2 totaling approximately $165 million (including $30 million for environmental controls), the Brown SCR totaling approximately $110 million, and information technology projects of approximately $35 million. See Note 9 of Notes to Financial Statements for additional information.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See the Contractual Obligations table below and Note 9 of Notes to Financial Statements for current commitments. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

KU has a variety of funding alternatives available to meet its capital requirements. KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds of up to $400 million available to the Company at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Notes 7 and 8 of Notes to Financial Statements.

Regulatory approvals are required for KU to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2007, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2009 allowing short-term borrowing of up to $400 million. As of December 31, 2008, KU has borrowed $16 million of this authorized amount. See Note 8 of Notes to Financial Statements.

KU's debt ratings as of December 31, 2008, were:

	Moody's	S&P
Unenhanced pollution control revenue bonds	A2	BBB+
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 7 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2008. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. See Statements of Capitalization.

(in millions)	Payments Due by Period						
Contractual Cash Obligations	2009	2010	2011	2012	2013	Thereafter	Total
Short-term debt (a)	$ 16	$ -	$ -	$ -	$ -	$ -	$ 16
Long-term debt	-	33	-	50	175	1,274(b)	1,532
Interest on long-term debt to affiliated company (c)	66	66	65	63	58	441	759
Interest on fixed rate bonds (d)	2	2	2	2	2	23	33
Operating leases (e)	9	5	4	4	3	6	31
Unconditional power purchase obligations (f)	26	17	10	10	10	155	228
Coal and gas purchase obligations (g)	442	387	363	217	59	-	1,468
Postretirement benefit plan obligations (h)	6	6	7	7	7	36	69
Other obligations (i)	119	3	1	-	-	-	123
Total contractual cash obligations	$ 686	$ 519	$ 452	$ 353	$ 314	$ 1,935	$ 4,259

(a) Represents borrowings from affiliated company due within one year.
(b) Includes long-term debt of $228 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2023 to 2034.
(c) Represents future interest payments on long-term debt to affiliated company.
(d) Represents interest on fixed rate long-term bonds. Future interest obligations on variable rate long-term bonds cannot be quantified.
(e) Represents future operating lease payments.
(f) Represents future minimum payments under OMU and OVEC power purchase agreements through 2010 and 2026, respectively.
(g) Represents contracts to purchase coal and natural gas transportation. Obligations for 2014 and 2015 are indexed to future market prices and will not be included above until prices are set using the contracted methodology.
(h) Represents currently projected cash flows for the postretirement benefit plan as calculated by the actuary. For pension funding information see Note 5 of Notes to Financial Statements.
(i) Represents construction commitments, including commitments for TC2 and the FGDs.

CONTROLS AND PROCEDURES

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

KU is not subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the “Act”) and consequently is not required to evaluate the effectiveness of the Company’s internal control over financial reporting pursuant to Section 404 of the Act. However, management has assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2008, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2008, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company’s internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2008 KU financial statements and additional information.

Kentucky Utilities Company
Balance Sheets
(Millions of $)

	December 31 2008	December 31 2007
ASSETS:		
Current assets:		
Cash and cash equivalents (Note 1)	$ 2	$ -
Restricted cash (Note 1)	10	11
Accounts receivable - less reserve of $3 million and $2 million in 2008 and 2007, respectively (Note 1)	165	172
Accounts receivable from affiliated companies (Note 11)	12	17
Materials and supplies (Note 1):		
Fuel (predominantly coal)	73	42
Other materials and supplies	36	34
Prepayments and other current assets	10	12
Total current assets	308	288
Other property and investments (Note 1)	29	29
Utility plant, at original cost (Note 1):	4,446	3,868
Less: reserve for depreciation	1,724	1,622
Total utility plant, net	2,722	2,246
Construction work in progress	1,176	1,071
Total utility plant and construction work in progress	3,898	3,317
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	127	28
Other	96	86
Cash surrender value of key man life insurance	39	37
Other assets	11	11
Total deferred debits and other assets	273	162
Total Assets	$ 4,508	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(Millions of $)

	December 31 2008	December 31 2007
LIABILITIES AND EQUITY:		
Current liabilities:		
Current portion of long-term debt (Note 7)	$ 228	$ 33
Notes payable to affiliated companies (Notes 8 and 11)	16	23
Accounts payable	161	160
Accounts payable to affiliated companies (Note 11)	38	48
Customer deposits	21	20
Other current liabilities	27	28
Total current liabilities	491	312
Long-term debt:		
Long-term bonds (Note 7)	123	300
Long-term debt to affiliated company (Note 7)	1,181	931
Total long-term debt	1,304	1,231
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 6)	280	285
Accumulated provision for pensions and related benefits (Note 5)	186	83
Investment tax credit (Note 6)	80	55
Asset retirement obligations	32	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	329	310
Deferred income taxes	16	22
Other	20	10
Other liabilities	26	23
Total deferred credits and other liabilities	969	818
Commitments and contingencies (Note 9)		
COMMON EQUITY:		
Common stock, without par value -		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital (Note 11)	241	90
Retained earnings	1,174	1,016
Undistributed subsidiary earnings	21	21
Total retained earnings	1,195	1,037
Total common equity	1,744	1,435
Total Liabilities and Equity	$ 4,508	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Millions of $)

	Years Ended December 31 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 158	$ 167
Items not requiring cash currently:		
Depreciation and amortization	136	121
Deferred income taxes - net	(13)	(5)
Investment tax credit - net	25	42
Provision for pension and postretirement plans	10	11
Other	1	(4)
Change in certain current assets and liabilities:		
Accounts receivable	12	(16)
Materials and supplies	(33)	22
Accounts payable	9	(15)
Accrued income taxes	4	2
Property and other taxes payable	(6)	(5)
Prepayments and other current assets	(1)	1
Other current liabilities	7	5
Pension and postretirement funding	(5)	(19)
Wind storm regulatory asset	(2)	-
Environmental cost recovery receivable	(9)	(1)
Fuel adjustment clause receivable, net	9	(4)
Other	(5)	5
Net cash provided by operating activities	297	307
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(690)	(745)
Assets transferred from affiliate	(10)	-
Change in non-hedging derivative liability	(1)	-
Change in restricted cash	1	12
Net cash used for investing activities	(700)	(733)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings from affiliated company (Note 7)	250	448
Short-term borrowings from affiliated company (Note 8)	201	289
Repayment of short-term borrowings from affiliated company	(208)	(363)
Retirement of first mortgage bonds	-	(107)
Issuance of pollution control bonds	77	78
Retirement of pollution control bonds	(60)	-
Acquisition of outstanding bonds	(80)	-
Reissuance of reacquired bonds	63	-
Retirement of reacquired bonds	17	-
Additional paid-in capital	145	75
Net cash provided by financing activities	405	420
Change in cash and cash equivalents	2	(6)
Cash and cash equivalents at beginning of year	-	6
Cash and cash equivalents at end of year	$ 2	$ -
Supplemental disclosures of cash flow information:		
Cash paid during the year for:		
Income taxes	$ 50	$ 38
Interest on borrowed money	13	16
Interest to affiliated companies on borrowed money	53	29

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization
(Millions of $)

	December 31 2008	December 31 2007
LONG-TERM DEBT (Note 7):		
Pollution control series:		
Mercer Co. 2000 Series A, due May 1, 2023, variable %	$ 13	$ 13
Carroll Co. 2002 Series A, due February 1, 2032, variable %	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable %	2	2
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable %	8	8
Carroll Co. 2002 Series C, due October 1, 2032, variable %	96	96
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Carroll Co. 2005 Series A, due June 1, 2035, variable %	-	13
Carroll Co. 2005 Series B, due June 1, 2035, variable %	-	13
Carroll Co. 2006 Series A, due June 1, 2036, variable %	-	17
Carroll Co. 2006 Series B, due October 1, 2034, variable %	54	54
Carroll Co. 2006 Series C, due June 1, 2036, variable %	-	17
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%	18	18
Trimble Co. 2007 Series A, due March 1, 2037, 6.0%	9	9
Carroll Co. 2008 Series A, due February 1, 2032, variable %	78	-
Total pollution control series	351	333
Notes payable to Fidelia:		
Due November 24, 2010, 4.24%, unsecured	33	33
Due January 16, 2012, 4.39%, unsecured	50	50
Due April 30, 2013, 4.55%, unsecured	100	100
Due August 15, 2013, 5.31%, unsecured	75	75
Due December 19, 2014, 5.45%, unsecured	100	100
Due July 8, 2015, 4.735%, unsecured	50	50
Due December 21, 2015, 5.36%, unsecured	75	75
Due October 25, 2016, 5.675%, unsecured	50	50
Due June 20, 2017, 5.98%, unsecured	50	50
Due July 25, 2018, 6.16%, unsecured	50	-
Due August 27, 2018, 5.645%, unsecured	50	-
Due December 17, 2018, 7.035%, unsecured	75	-
Due October 25, 2019, 5.71%, unsecured	70	70
Due February 7, 2022, 5.69%, unsecured	53	53
Due May 22, 2023, 5.85%, unsecured	75	-
Due September 14, 2028, 5.96%, unsecured	100	100
Due June 23, 2036, 6.33%, unsecured	50	50
Due March 30, 2037, 5.86%, unsecured	75	75
Total notes payable to Fidelia	1,181	931
Total long-term debt outstanding	1,532	1,264
Less current portion of long-term debt	228	33
Long-term debt	1,304	1,231
COMMON EQUITY:		
Common stock, without par value -		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in-capital (Note 11)	241	90
Retained earnings	1,174	1,016
Undistributed subsidiary earnings	21	21
Total retained earnings	1,195	1,037
Total common equity	1,744	1,435
Total capitalization	$ 3,048	$ 2,666

The accompanying notes are an integral part of these financial statements.

Note 1 - Summary of Significant Accounting Policies

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 508,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. Approximately 99% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

Regulatory Accounting. KU is subject to SFAS No. 71, under which regulatory assets are created based on expected recovery from customers in future rates to defer costs that would otherwise be charged to expense. Likewise, regulatory liabilities are created based on expected return to customers in future rates to defer credits that would otherwise be reflected as income, or, in the case of costs of removal, are created to match long-term future obligations arising from the current use of assets. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC, the Kentucky Commission or the Virginia Commission. See Note 2, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Cash and Cash Equivalents. KU considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets.

Allowance for Doubtful Accounts. The allowance for doubtful accounts is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter.

Materials and Supplies. Fuel and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies and are not currently traded by KU. At December 31, 2008 and 2007, the emission allowances inventory was less than $1 million.

Other Property and Investments. Other property and investments on the balance sheets consists of KU's investment in EEI, economic development loans provided to various communities in the service territory, KU's investment in OVEC, funds related to the long-term purchased power contract with OMU and non-utility plant.

Although KU holds investment interests in OVEC and EEI, it is not the primary beneficiary, therefore, neither are consolidated into the Company's financial statements. KU and 11 other electric utilities are participating owners of OVEC, located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana. Pursuant to current contractual agreements, KU's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity.

As of December 31, 2008 and 2007, KU's investment in OVEC totaled less than $1 million and is accounted for under the cost method of accounting. The direct exposure to loss as a result of its involvement with OVEC is generally limited to the value of its investment. In the event of the inability of OVEC to fulfill its power provision requirements, KU anticipates substituting such power supply with either owned generation or market purchases and believes it would generally recover associated incremental costs through regulatory rate mechanisms. See Note 9, Commitments and Contingencies, for further discussion of developments regarding KU's ownership interests and power purchase rights.

KU owns 20% of the common stock of EEI, which owns and operates a 1,162-Mw generating station in southern Illinois. KU's investment in EEI is accounted for under the equity method of accounting and, as of December 31, 2008 and 2007, totaled $22 million and $23 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment.

Utility Plant. Utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates in Kentucky. KU has not recorded a significant allowance for funds used during construction.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided were approximately 3.0% in 2008 and 3.2% in 2007 of average depreciable plant. Of the amount provided for depreciation at December 31, 2008 and 2007, approximately 0.5% was related to the retirement, removal and disposal costs of long lived assets.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized using the straight line method, which approximates the effective interest method, over the lives of the related bond issues.

Income Taxes. Income taxes are accounted for under SFAS No. 109, *Accounting for Income Taxes* and FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109*. In accordance with these statements, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are transactions for which the ultimate tax outcome is uncertain. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Uncertain tax positions are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 6, Income Taxes.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. KU and LG&E received an investment tax credit related to TC2. See Note 6, Income Taxes. Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of KU's tax liability based on credits for construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. KU accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable were $60 million and $59 million at December 31, 2008 and 2007, respectively.

Fuel Costs. The cost of fuel for generation is charged to expense as used.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environmental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Recent Accounting Pronouncements. The following are recent accounting pronouncements affecting KU:

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The adoption of SFAS No. 161 will have no impact on KU's statements of operations, financial position and cash flows, however, additional disclosures relating to derivatives will be required beginning in the first quarter of 2009.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 was adopted effective January 1, 2008 and the Company elected not to fair value its eligible financial assets and liabilities.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments related to SFAS No. 157 have been evaluated and have no impact on the Company's financial statements. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives and cash collateral on derivatives, as required, are now provided. Per FASB Staff Position 157-2, fair value accounting for all nonrecurring fair value measurements of nonfinancial assets and liabilities will be adopted effective January 1, 2009.

Note 2 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to SFAS No. 71. Given its position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of SFAS No. 71.

Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in base electric rates. In conjunction with the filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008. In January 2009, KU, the AG, KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's base electric rates will decrease by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated.

The VDT surcredit originated in December 2001, when the Kentucky Commission issued an Order approving a settlement agreement allowing KU to set up a regulatory asset of $54 million for workforce reduction costs and begin amortizing it over a five-year period starting in April 2001. The Order also provided for a surcredit to be included on customers' bills representing 40% of the annual savings derived from this initiative. For periods beginning January 1, 2006, the VDT surcredit had increased to $4 million per year.

In February 2006, KU and all parties to the proceeding reached a unanimous settlement agreement on the future ratemaking treatment of the VDT surcredit. Under the terms of the settlement agreement, the VDT surcredit continued at its current level until such time as KU filed for a change in base rates. The Kentucky Commission issued an Order in March 2006, approving the settlement agreement. In accordance with the Order, the VDT surcredit terminated in August 2008, the first billing month after the July 2008 filing for a change in base rates.

The merger surcredit originated as part of the LG&E Energy merger with KU Energy Corporation in 1998. It was based on estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings were deferred and amortized over a five-year period pursuant to regulatory orders. In approving the merger, the Kentucky Commission adopted KU's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. These savings were provided in the form of a surcredit mechanism on customers' bills. In October 2003, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case in which the merger surcredit of $18 million per year would remain in place for another five-year term beginning July 1, 2003, and KU would file a plan for the merger surcredit six months before its expiration.

In December 2007, KU submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. In June 2008, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case which provided for a reduction in the merger surcredit to approximately $6 million for a 7-month period beginning July 2008, termination of the merger surcredit when new base rates went into effect on or after January 31, 2009, and that the annual merger surcredit be continued at an annual rate of $12 million thereafter should the Company not file for a change in base rates. In accordance with the Order, the merger surcredit was terminated effective February 6, 2009, with the implementation of new base rates.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in base electric rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requests a shift from current, all-in stated unit charge rates to an unbundled and formula rate. The revised rates represent varying increases of 6% to 7% from current charges and include a change from the all-in stated applicable return on equity of 11.8%. The proceeding involves data requests and hearings before the FERC, as well as data requests and filings by intervenors. In November 2008, the FERC issued an Order to suspend rates until May 1, 2009, at which time the applied for rates will become effective, subject to potential refund or adjustment commencing in October 2009, based upon the outcome of the proceedings. Concurrently with the progress of the FERC rate proceedings, KU and the municipal customers have commenced structured settlement negotiations overseen by the FERC.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the balance sheets as of December 31:

(in millions)	2008	2007
ARO	$ 28	$ 24
MISO exit	19	20
Unamortized loss on bonds	13	10
FAC	9	17
ECR	20	11
Hurricane Ike	2	-
Other	5	4
Subtotal	96	86
Pension and postretirement benefits	127	28
Total regulatory assets	$ 223	$ 114
Accumulated cost of removal of utility plant	$ 329	$ 310
Deferred income taxes – net	16	22
Other	20	10
Total regulatory liabilities	$ 365	$ 342

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. KU will recover this asset through the pension expense included in the calculation of base rates with the Kentucky Commission and will seek recovery of this asset in future proceedings with the Virginia Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. Approval for the recovery of this asset was received from the Kentucky Commission as part of the 2008 base rate case and KU will seek recovery of this asset in future proceedings with the Virginia Commission. KU currently earns a rate of return on remaining regulatory assets, including other regulatory assets comprised of VDT costs (2007 only), merger surcredit and deferred storm costs. Other regulatory assets also include KCCS funding (see CMRG and KCCS Contributions below), FERC jurisdictional pension expense and rate case expenses. KU will seek recovery of the KCCS funding in the next base rate case and received approval for the recovery of the rate case expenses as part of the 2008 base rate case. Other regulatory liabilities include DSM and MISO costs included in base rates that will be netted against costs of withdrawing from the MISO as part of the settlement agreement in the 2008 base rate case.

ARO. A summary of KU's net ARO assets, regulatory assets, ARO liabilities, regulatory liabilities and cost of removal established under FIN 47, *Accounting for Conditional Asset Retirement Obligations, an Interpretation of SFAS No. 143,* and SFAS No. 143, *Accounting for Asset Retirement Obligations,* follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets	Regulatory Liabilities	Accumulated Cost of Removal	Cost of Removal Depreciation
As of December 31, 2006	$ 5	$ (28)	$ 22	$ (2)	$ 2	$ 1
ARO accretion	-	(2)	2	-	-	-
As of December 31, 2007	5	(30)	24	(2)	2	1
ARO accretion	-	(2)	2	-	-	-
Removal cost reclass	-	-	2	(2)	-	-
As of December 31, 2008	$ 5	$ (32)	$ 28	$ (4)	$ 2	$ 1

Pursuant to regulatory treatment prescribed under SFAS No. 71, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million in 2008 and 2007 for the ARO accretion and depreciation expense. KU AROs are primarily related to the final retirement of assets associated with generating units. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory liability pursuant to regulatory treatment prescribed under SFAS No. 71. There were no FIN 47 net asset additions during 2008 or 2007. For the years ended December 31, 2008 and 2007, KU recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under SFAS No. 71.

KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations are recorded for transmission and distribution assets.

MISO. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, KU withdrew from the MISO effective September 1, 2006. Specific proceedings regarding the costs and benefits of the MISO and exit matters had been underway since July 2003. Since the exit from the MISO, KU has been operating under a FERC-approved open access-transmission tariff. KU now contracts with the Tennessee Valley Authority to act as its transmission Reliability Coordinator and Southwest Power Pool, Inc. to function as its Independent Transmission Organization, pursuant to FERC requirements.

KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of $1 million and an estimated $3 million over the next seven years for credits realized from other payments the MISO will receive, plus interest. In accordance with Kentucky Commission Orders approving the MISO exit, KU has established a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The approved base rate case settlement provided for MISO Schedule 10 expenses collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. KU and other parties have requested rehearing and a delay in any collection of RSG amounts. During January and February 2009, the FERC issued a deficiency letter in the proceeding relating to one prior Order, which delays collection of applicable RSG resettlements by the MISO pending further proceedings. Further developments in the RSG proceeding are expected to occur during 2009. Due to the numerous participants, complex principles at issue and changes from prior precedents, KU cannot predict the ultimate outcome of this matter. Based upon the recent FERC Orders, KU established a reserve during the fourth quarter of 2008, of less than $1 million relating to potential RSG resettlement costs for the period ended December 31, 2008.

Unamortized Loss on Bonds. The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

FAC. KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges.

In January 2009, the Kentucky Commission initiated a routine examination of KU's FAC for the two-year period November 1, 2006 through October 31, 2008. A public hearing is scheduled in March 2009. An order is anticipated in the second quarter of 2009.

In August 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period November 1, 2007 through April 30, 2008. The Kentucky Commission issued an Order in January 2009, approving the charges and credits billed through the FAC during the review period.

In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in June 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

In December 2006, the Kentucky Commission initiated its periodic two-year review of KU's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates for November 1, 2004 through October 31, 2006. In March 2007, the KIUC challenged KU's recovery of approximately $5 million in aggregate fuel costs KU incurred during a period prior to its exit from the MISO and requested the Kentucky Commission disallow this amount. A public hearing was held in May 2007. In October 2007, the Kentucky Commission issued its Order approving the calculation and application of KU's FAC charges and fuel procurement practices and indicated that KU was in compliance with the provisions of Administrative Regulation 807 KAR 5:5056. The Kentucky Commission further approved KU's recommendation for the transfer of fuel cost from the FAC to base rates. In November 2007, the KIUC filed a petition for rehearing, claiming the Kentucky Commission misinterpreted the KIUC's arguments in the proceeding. In the same month, the Kentucky Commission issued an Order denying the KIUC's request for rehearing. An appeal was not filed by the KIUC.

In January 2003, the Kentucky Commission reviewed KU's FAC for the six-month period ended October 31, 2001. The Kentucky Commission ordered KU to reduce its fuel costs for purposes of calculating its FAC by less than $1 million. At issue was the purchase of approximately 102,000 tons of coal from Western Kentucky Energy Corp., a non-regulated affiliate, for use at KU's Ghent facility. The Kentucky Commission further ordered that an independent audit be conducted to examine operational and management aspects of both KU's and LG&E's fuel procurement functions. The final report's recommendations, issued in February 2004, related to documentation and process improvements. Management Audit Action Plans were agreed upon by KU and the Kentucky Commission Staff in the second quarter of 2004, and resulted in Audit Progress Reports being filed by KU with the Kentucky Commission. In February 2007, the Kentucky Commission staff indicated that KU fully complied with all audit recommendations and that no further reports are required.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The factor may be adjusted annually for over- or under-collections of fuel costs from the prior year. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kwh from the factor in effect for the April 2007 through March 2008 period.

ECR. Kentucky law permits KU to recover the costs of complying with the Federal Clean Air Act, including a return of operating expenses, and a return of and on capital invested, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the March 2009 expense month filing, which represents a slight increase over the current 10.50%.

In January 2009, the Kentucky Commission initiated a six-month review for the period ending October 31, 2008, of KU's environmental surcharge. An order is anticipated in the second quarter of 2009.

In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of KU's environmental surcharge. The Kentucky Commission issued an Order in

August 2008, approving the charges and credits billed through the ECR during the review period and the rate of return on capital.

In October 2007, KU met with the Kentucky Commission and other interested parties to discuss the status of the Ghent Unit 2 SCR construction. KU informed the Kentucky Commission that construction of the Ghent Unit 2 SCR was not going to commence before the CCN expired in December 2007, due to a change in the economics for the project. The CCN expired in December 2007, and KU has delayed construction of the Ghent Unit 2 SCR.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. The Kentucky Commission issued a final Order in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Hurricane Ike. In September 2008, high winds from the remnants of Hurricane Ike passed through the service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike.

FERC Jurisdictional Pension Costs. Pension costs of $3 million incurred by the Company allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in the next FERC rate proceeding.

Rate Case Expenses. KU incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

CMRG and KCCS Contributions. In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and KU will seek rate recovery in the Company's next base rate case.

Deferred Storm Costs. Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset, $4 million related to costs not reimbursed from the 2003 ice storm. These costs will be amortized through June 2009. KU earns a return of these amortized costs, which are included in jurisdictional operating expenses.

Pension and Postretirement Benefits. KU adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* in 2006. This statement requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under SFAS No. 71, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on SFAS No. 87, *Employers' Accounting for Pensions,* and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions,* both of which were amended by SFAS No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery, therefore, the Company has recorded a regulatory asset representing the change in funded status of the pension and postretirement plans that is expected to be recovered. The regulatory asset will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Accumulated Cost of Removal of Utility Plant. As of December 31, 2008 and 2007, KU has segregated the cost of removal, previously embedded in accumulated depreciation, of $329 million and $310 million, respectively, in accordance with FERC Order No. 631. This cost of removal component is for assets that do not have a legal ARO under SFAS No. 143. For reporting purposes in the balance sheets, KU has presented this cost of removal as a regulatory liability pursuant to SFAS No. 71.

Deferred Income Taxes – Net. These regulatory assets and liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits, the allowance for funds used during construction and deferred taxes provided at rates in excess of currently enacted rates.

DSM. KU's rates contain a DSM provision. The provision includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Other Regulatory Matters

Storm Restoration. In January 2009, a significant winter ice storm passed through KU's service territory causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. KU currently estimates costs incurred of $66 million of expenses and $28 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave customers the ability to choose their electric supplier and capped electric rates through December 2010. KU subsequently received a legislative exemption from the customer choice requirements of this law. In April 2007, however, the Virginia General Assembly amended the Virginia Electric Utility Restructuring Act, thereby terminating this competitive market and commencing re-regulation of utility rates. The new act ended the cap on rates at the end of 2008. Pursuant to this legislation, the Virginia Commission adopted regulations revising the rules governing utility rate increase applications. As of January 2009, a hybrid model of regulation is being applied in Virginia. Under this model, utility rates are reviewed every two years. KU's exemption from the requirements of the Virginia Electric Utility Restructuring Act in 1999, however, discharges KU from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, KU has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case. KU is also subject to other utility regulations in Virginia, including, but not limited to, the recovery of prudently incurred fuel costs through an annual fuel factor charge and the submission of integrated resource plans.

Regional Reliability Council. KU has changed its regional reliability council membership from the Reliability First Corporation to the SERC, effective January 1, 2007. Regional reliability councils are industry consortiums that promote, coordinate and ensure the reliability of the bulk electric supply systems in North America.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by KU and LG&E, together with the IMEA and the IMPA, was approved by the Kentucky Commission in November 2005.

CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

The CCN for the remaining line has been challenged by certain Hardin County, Kentucky property owners. In August 2006, KU and LG&E obtained a successful dismissal of the challenge at the Franklin County circuit court, which ruling was reversed by the Kentucky Court of Appeals in December 2007, and the proceeding reinstated. The matter is currently before the Kentucky Supreme Court on a motion for discretionary review filed by KU and LG&E in May 2008. The motion, which seeks reversal of the appellate court decision and reinstatement of the circuit court dismissal of the challenge has not yet been ruled upon.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures and certain Hardin County landowners have raised challenges to such transmission line in some of these forums as well. During 2008, KU and LG&E obtained various successful rulings at the Hardin County circuit court establishing their condemnation and easement rights. In August 2008, the landowners appealed such rulings to the Kentucky Court of Appeals and received a stay preventing KU and LG&E access to the properties during the appeal. KU and LG&E have petitioned the appellate court to lift the stay and otherwise sustain the lower court ruling, but such matter has not yet been ruled upon. In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky, claiming that certain National Historic Preservation Act requirements were not fully complied with by the U.S. Army relating to easements for the line through Fort Knox. KU and LG&E are cooperating with the U.S. Army in its defense in this case.

KU and LG&E continue to actively engage in settlement negotiations with the Hardin County property owners involved in the appeals of the condemnation proceedings. During the fourth quarter of 2008, KU and LG&E entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they had brought challenging the same transmission line. KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to these transmission line approval and land acquisition proceedings.

Ghent FGD Inquiry. In October 2006, the Kentucky Commission commenced an inquiry into elements of KU's planned construction of one of its three new FGDs at the Ghent generating station. The proceeding requested, and the Company provided, additional information regarding configuration details, expenditures and the proposed construction sequence applicable to future construction phases of the Ghent FGD project. In January 2007, the Kentucky Commission issued an Order completing its inquiry in the matter and confirming its approval of KU's construction plan. The Order also provided general guidance for jurisdictional utilities regarding applicable information and data requirements for future CCN applications and subsequent proceedings.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting KU's further proposal to address certain market power issues the FERC had claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of control areas in which it may be deemed to have market power, subject to a restriction that such power not be collusively re-sold back into such control areas. However, restrictions exist on sales by KU of power at market-based rates in the KU/LG&E and Big Rivers Electric Corporation control areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for KU's power sales at control area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. The Order is subject to a FERC rehearing process during which time the FERC has delayed implementation of the provisions relating to sales at interfaces. The Company cannot determine its ultimate impact at this time. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC's regulation. During September 2008, KU submitted a regular tri-annual update filing under market-based rate regulations and FERC review proceedings for such filing remain in progress.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. During May 2008, the SERC and KU agreed to a settlement involving penalties totaling less than $1 million related to KU's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. The SERC and KU are currently involved in settlement negotiations concerning a June 2008 self-report by KU relating to three other standards and an October 2008 self-report of a possible violation relating to an additional standard. SERC proceedings for these June and October self-reports are in the early stages and therefore the outcome is unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. In December 2008, the SERC commenced a routine, periodic audit of KU and LG&E relating to certain designated reliability standards. This audit was completed during the first quarter of 2009 with no violations identified. While KU believes itself to be in compliance with the mandatory reliability standards, the Company cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

IRP. Integrated resource planning regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, KU and LG&E filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The AG and the KIUC were granted intervention in the IRP proceeding. During September 2008, KU and LG&E responded to public comments and they are awaiting the Kentucky Commission staff report which will close this proceeding. KU and LG&E are not able to predict further proceedings at this time.

PUHCA 2005. E.ON, KU's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005. The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005 and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252, Smart Metering standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254, Interconnection standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. Data discovery concluded in July 2007, and no parties to the case requested a hearing. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU will file annual reports on the program within 90 days of each plan year-end for the 3-year pilot period.

Green Energy Riders. In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. The AG and KIUC were granted full intervention. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits.

Home Energy Assistance Program. In July 2007, KU filed an application with the Kentucky Commission for the establishment of a new Home Energy Assistance program. During September 2007, the Kentucky Commission approved the new five-year program as filed, effective in October 2007. The program terminates in September 2012, and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge.

Collection Cycle Revision. As part of the base rate case filed on July 29, 2008, LG&E proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreement approved in the rate case in February 2009, changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E, and KU will implement a late payment charge if payment is not received within 15 days from the bill issuance date.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission. In July 2008, KU filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The settlement agreement in the rate case established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission, but has not requested formal review and approval of the depreciation rates from the Virginia Commission. Such a review will take place either during KU's next base rate case in Virginia or when KU makes a formal application to the Virginia Commission for approval of the proposed rates.

Brownfield Development Rider Tariff. In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. KU does not expect any impact as a result of this Order. KU shall file revised net metering tariffs and application forms within ninety days of the Order to comply with the new guidelines.

EISA 2007 Standards. In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and nonregulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008 and to complete the consideration by December 19, 2009.

Note 3 - Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of December 31 follow:

	2008		2007	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $228 million)	$ 351	$ 349	$ 333	$ 333
Long-term debt from affiliate	$ 1,181	$ 1,117	$ 931	$ 996

The long-term debt valuations reflect prices quoted by dealers. The fair value of the long-term debt from affiliate is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates. The current market rates are determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU's credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU is subject to the risk of fluctuating interest rates in the normal course of business. KU's policies allow the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2008, a 100 basis point change in the benchmark rate on KU's variable rate debt would impact pre-tax interest expense by $3 million annually. Although KU's policies allow for the use of interest rate swaps, as of December 31, 2008, KU had no interest rate swaps outstanding.

Energy Trading and Risk Management Activities. KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with SFAS No. 133, as amended.

Energy trading and risk management contracts are valued using prices based on active trades on the Intercontinental Exchange ("ICE"). In the absence of a traded price, midpoints of the best bids and offers will be the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs can include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers, as of the balance sheet date. Using these valuation methodologies, these contracts are considered level 2 based on SFAS No. 157 measurement criteria. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2008 and 2007, had a maturity of less than one year and were considered to be in a liquid market.

KU maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2008, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. KU has reserved against counterparty credit risk based on the counterparty's credit rating and applying historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2008 and 2007, counterparty credit reserves were less than $1 million.

KU manages the price volatility of its forecasted electric wholesale sales with the sales of market-traded electric forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income. Unrealized gains and losses are included in other expense – net, whereas realized gains and losses are included in operating revenues. Unrealized losses were $1 million and unrealized gains were less than $1 million in 2008 and 2007, respectively. Realized gains and losses were less than $1 million in 2008 and 2007.

Effective January 1, 2008, KU adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. KU has classified the applicable financial assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157.

The following table sets forth by level within the fair value hierarchy KU's financial assets that were accounted for at fair value on a recurring basis as of December 31, 2008. Cash collateral related to the energy trading and risk management contracts totals less than $1 million, is categorized as restricted cash and is a level 1 measurement based on the funds being held in liquid accounts. Liabilities accounted for at fair value total less than $1 million and use level 2 measurements. There are no level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1	Level 2	Total
Financial Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Total Financial Assets	$ -	$ 1	$ 1

Note 4 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

KU's customer receivables and revenues arise from deliveries of electricity to approximately 508,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. For the years ended December 31, 2008 and 2007, 100% of total revenue was derived from electric operations. During 2008, KU's 10 largest customers accounted for less than 10% of electric volumes.

Effective August 1, 2006, KU and its employees represented by the IBEW Local 2100 entered into a new three-year collective bargaining agreement. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. Wage re-openers were negotiated and agreed to in July 2007 and July 2008. KU and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 16% of KU's workforce at December 31, 2008.

Note 5 - Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded non-contributory defined benefit pension plans and other postretirement benefit plans that together cover employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The Company makes an annual lump sum contribution to the RIA, based on years of service and a percentage of covered compensation. The health care plans are contributory with participants' contributions adjusted annually. KU uses December 31 as the measurement date for its plans.

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2008, and a statement of the funded status as of December 31 for KU's sponsored defined benefit plans:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Change in benefit obligation				
Benefit obligation at beginning of year	$ 284	$ 303	$ 76	$ 88
Service cost	5	6	1	2
Interest cost	18	17	5	5
Benefits paid, net of retiree contributions	(18)	(19)	(3)	(5)
Actuarial (gain)/loss and other	17	(23)	(4)	(14)
Benefit obligation at end of year	$ 306	$ 284	$ 75	$ 76
Change in plan assets				
Fair value of plan assets at beginning of year	$ 264	$ 253	$ 13	$ 12
Actual return on plan assets	(61)	17	(3)	-
Employer contributions	-	13	5	6
Benefits paid, net of retiree contributions	(18)	(19)	(3)	(5)
Administrative expenses and other	(2)	-	-	-
Fair value of plan assets at end of year	$ 183	$ 264	$ 12	$ 13
Funded status at end of year	$ (123)	$ (20)	$ (63)	$ (63)

Amounts Recognized in Statement of Financial Position. The following tables provide the amounts recognized in the balance sheets and information for plans with benefit obligations in excess of plan assets as of December 31:

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Regulatory assets	$ 137	$ 37	$ (10)	$ (9)
Accrued benefit liability (non-current)	(123)	(20)	(63)	(63)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets:

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Benefit obligation	$ 306	$ 284	$ 75	$ 76
Accumulated benefit obligation	261	243	-	-
Fair value of plan assets	183	264	12	13

For discussion of the pension and postretirement regulatory assets, see Note 2, Rates and Regulatory Matters.

Components of Net Periodic Benefit Cost. The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and E.ON U.S. Services' employees, who are providing services to the utility. The E.ON U.S. Services' costs that are allocated to KU are approximately 46% and 45% of E.ON U.S. Services' total cost for 2008 and 2007, respectively.

(in millions)	Pension Benefits					
	KU 2008	Servco Allocation to KU 2008	Total KU 2008	KU 2007	Servco Allocation to KU 2007	Total KU 2007
Service cost	$ 6	$ 4	$ 10	$ 6	$ 4	$ 10
Interest cost	18	6	24	17	5	22
Expected return on plan assets	(21)	(5)	(26)	(21)	(5)	(26)
Amortization of prior service costs	1	1	2	1	1	2
Amortization of actuarial loss	-	-	-	2	1	3
Benefit cost at end of year	$ 4	$ 6	$ 10	$ 5	$ 6	$ 11

Other Postretirement Benefits

	KU 2008	Servco Allocation to KU 2008	Total KU 2008	KU 2007	Servco Allocation to KU 2007	Total KU 2007
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Expected return on plan assets	(1)	-	(1)	(1)	-	(1)
Amortization of transitional obligation	1	-	1	1	-	1
Benefit cost at end of year	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The assumptions used in the measurement of KU's pension benefit obligation are shown in the following table:

	2008	2007
Weighted-average assumptions as of December 31:		
Discount rate	6.25%	6.66%
Rate of compensation increase	5.25%	5.25%

The discount rates were determined by the December 29, 2008, Mercer Pension Discount Yield Curve. These discount rates were then lowered by 2 basis points for the average change in 4 bond indices, Citigroup High Grade Credit Index AAA/AA 10+ years, Lehman Brothers US AA Long Credit, Merrill Lynch US Corporate AA-AAA rated 10+ years and Merrill Lynch US Corporate AA rated 15+ years, for the period from December 29, 2008 to December 31, 2008.

The assumptions used in the measurement of KU's net periodic benefit cost are shown in the following table:

	2008	2007
Discount rate	6.66%	5.96%
Expected long-term return on plan assets	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate could have an approximate $31 million positive or negative impact to the 2008 accumulated benefit obligation and an approximate $42 million positive or negative impact to the 2008 projected benefit obligation.

- A 25 basis point change in the expected rate of return on assets would have an approximate $1 million positive or negative impact on 2008 pension expense.

Assumed Health care Cost Trend Rates. For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for 2008. The rate was assumed to decrease gradually to 5% by 2016 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million on the 2008 total of service and interest costs components and an increase or decrease of $4 million in year-end 2008 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts. The following list provides the amount of expected future benefit payments, which reflect expected future service and the estimated gross amount of Medicare subsidy receipts:

(in millions)	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2009	$ 18	$ 7	$ 1
2010	18	7	-
2011	17	7	1
2012	17	7	-
2013	17	7	1
2014-18	94	39	3

Plan Assets. The following table shows KU's weighted-average asset allocation by asset category at December 31:

Pension Plans	Target Range	2008	2007
Equity securities	45% - 75%	55%	57%
Debt securities	30% - 50%	43	43
Other	0% - 10%	2	-
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Lehman Aggregate and Lehman U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that either are of short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

Contributions. KU made a discretionary contribution to the pension plan of $13 million in January 2007. In addition, contributions to other postretirement benefit plans of $5 million and $6 million were made in 2008 and 2007, respectively. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. In 2009, KU anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company has monitored developments regarding the Act and has made a number of elections to comply.

Thrift Savings Plans. KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were $3 million and $2 million for 2008 and 2007, respectively.

KU also makes contributions to retirement income accounts within its thrift savings plans for certain employees not covered by its noncontributory defined benefit pension plans. These employees consist mainly of those hired after December 31, 2005. KU makes these contributions based on years of service and the employees' wage and salary levels, and it makes them in addition to the matching contributions discussed above. The amounts contributed by KU under this arrangement equaled less than $1 million in 2008 and in 2007.

Note 6 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, E.ON US Investments Corp., for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. While the federal statute of limitations related to 2005 and later years are open, Revenue Agent Reports for 2005-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments made by the IRS for the 2005-2006 tax years were recorded in the 2008 financial statements. The tax year 2007 return was examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed. KU had no adjustments for the 2007 filed federal income tax return. The tax year 2008 return is also being examined under the CAP program.

KU adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Additions and reductions of uncertain tax positions during 2008 and 2007 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes.

Interest and penalties, if any, are recorded as operating expenses on the income statement and accrued expenses on the balance sheet. The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of December 31, 2008 and 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, KU accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by KU upon adoption of FIN 48, or through December 31, 2008.

Components of income tax expense are shown in the table below:

(in millions)		2008	2007
Current	- federal	$ 46	$ 28
	- state	10	13
Deferred	- federal – net	(10)	(5)
	- state – net	(3)	(1)
Investment tax credit – deferred		25	43
Amortization of investment tax credit		-	(1)
Total income tax expense		$ 68	$ 77

Current federal income tax expense increased and investment tax credit – deferred decreased primarily due to claiming $18 million less in investment tax credits in 2008. These investment tax credits are discussed further below. Current state income tax decreased due to coal credits claimed in 2008.

Deferred federal income tax decreased due to adjusting prior year estimates to actual based on the filed tax return.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $25 million and $43 million in 2008 and 2007, respectively, decreasing current federal income taxes. In addition, a full depreciation basis adjustment is required for the amount of the credit. The income tax expense impact of this adjustment will begin when the facility is placed in service.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. In August 2008, the plaintiffs submitted an amended complaint alleging additional claims for relief. In November 2008, the Court dismissed the suit; however, the plaintiffs filed a motion for reconsideration. The Company is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

Components of net deferred tax liabilities included in the balance sheets are shown below:

(in millions)	2008	2007
Deferred tax liabilities:		
Depreciation and other plant-related items	$ 284	$ 292
Regulatory assets and other	40	40
Total deferred tax liabilities	324	332
Deferred tax assets:		
Income taxes due to customers	6	9
Pensions and related benefits	19	17
Liabilities and other	22	23
Total deferred tax assets	47	49
Net deferred income tax liability	$ 277	$ 283
Balance sheet classification		
Current assets	$ (3)	$ (2)
Non-current liabilities	280	285
Net deferred income tax liability	$ 277	$ 283

KU expects to have adequate levels of taxable income to realize its recorded deferred tax assets.

A reconciliation of differences between the statutory U.S. federal income tax rate and KU's effective income tax rate follows:

	2008	2007
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	2.6	3.4
Reduction of income tax reserve	(0.2)	(0.4)
Qualified production activities deduction	(1.1)	(1.2)
Dividends received deduction related to EEI investment	(4.2)	(2.9)
Amortization of investment tax credits	(0.1)	(0.4)
Other differences	(1.9)	(1.9)
Effective income tax rate	30.1 %	31.6 %

State income taxes, net of federal benefit decreased due to state coal credits received in 2008. KU's effective income tax rate also decreased in 2008 as a result of increased dividends from its investment in EEI.

Note 7 - Long-Term Debt

As of December 31, 2008 and 2007, long-term debt and the current portion of long-term debt consist primarily of pollution control bonds and long-term loans from affiliated companies as summarized below.

(in millions)	Stated Interest Rates	Maturities	Principal Amounts
Outstanding at December 31, 2008:			
Noncurrent portion	Variable – 7.035%	2010-2037	$1,304
Current portion	Variable	2023-2034	$ 228
Outstanding at December 31, 2007:			
Noncurrent portion	Variable – 6.33%	2010-2037	$1,231
Current portion	Variable	2032	$ 33

Long-term debt includes $228 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County Series 2002 A and B, Muhlenberg County Series 2002 A, Mercer County Series 2002 A, Mercer County 2000 Series A, Carroll County 2004 Series A, Carroll County 2006 Series B and Carroll County 2008 Series A. Maturity dates for these bonds range from 2023 to 2034. The average annualized interest rate for these bonds during 2008 and 2007 was 1.75% and 3.72%, respectively.

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless the Company defaults on the loan agreement. Subsequent to February 2007, the loan agreement is an unsecured obligation of KU. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) were held in trust pending expenditure for qualifying assets. At December 31, 2008, and 2007, KU had $9 million and $11 million, respectively, of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the pollution control bonds are or were insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At December 31, 2008, KU had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" where there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture which can be as high as 15%. During 2008 and 2007, the average rate on the auction rate bonds was 4.50% and 3.96%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In 2008, the ratings of the following bonds were downgraded due to downgrades of the bond insurers or the termination of the bond insurance.

($ in millions)		Bond Rating			
		Moody's		S&P	
Tax Exempt Bond Issues	Principal	2008	2007	2008	2007
Mercer County 2000 Series A (1)	$ 13	Aaa	Aaa	AA+	AAA
Carroll County 2002 Series C	$ 96	A2	Aaa	A	AAA
Carroll County 2004 Series A (1)	$ 50	Aaa	Aaa	AA+	AAA
Carroll County 2005 Series A (2)	$ 13	-	Aaa	-	AAA
Carroll County 2005 Series B (2)	$ 13	-	Aaa	-	AAA
Carroll County 2006 Series A (2)	$ 17	-	Aaa	-	AAA
Carroll County 2006 Series B (1)	$ 54	Aaa	Aaa	AA+	AAA
Carroll County 2006 Series C (2)	$ 17	-	Aaa	-	AAA
Carroll County 2007 Series A	$ 18	A2	Aaa	A	AAA
Trimble County 2007 Series A	$ 9	A2	Aaa	A	AAA
Carroll County 2008 Series A (3)	$ 78	Aaa	-	AA+	-

(1) Bonds restructured in December 2008, and enhanced by letter of credit. Bond insurance terminated upon restructuring.
(2) Bonds defeased in October 2008. Proceeds combined with new bond allocation of $18 million to create new bond issue of $78 million without insurance enhancement.
(3) Bond issued in October 2008, without insurance enhancement. Bond restructured in December 2008, and enhanced by letter of credit.

In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. These conversions were completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively.

In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bonds and the Mercer County 2000 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent. In October 2008, the Carroll County 2006 Series C bonds, along with the Carroll County 2005 Series A and B and Carroll County 2006 Series A bonds, were defeased.

In June 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2004 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, KU purchased the bonds from the remarketing agent.

In November 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series B and Carroll County 2008 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in December 2008. In connection with the conversions, the bond insurance policy associated with the bonds was terminated and replaced with letters of credit.

In December 2008, KU remarketed the Mercer County 2000 Series A and Carroll County 2004 Series A bonds. In connection with the conversions, the bond insurance policy associated with the bonds was terminated and replaced with letters of credit.

As of December 31, 2008, KU had no remaining repurchased bonds. KU refinanced and remarketed $63 million and refinanced $17 million of pollution control bonds that had been previously repurchased by the Company.

All of KU's first mortgage bonds were released and terminated in February 2007. Only the tax-exempt pollution control revenue bonds issued by the counties remain. Under the provisions for certain of KU's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for these bonds during 2008 and 2007 was 1.75% and 3.72%, respectively.

Redemptions and maturities of long-term debt for 2008 and 2007 are summarized below:

($ in millions)		Principal		Secured/	
Year	Description	Amount	Rate	Unsecured	Maturity
2008	Pollution control bonds	$ 13	Variable	Secured	2035
2008	Pollution control bonds	$ 13	Variable	Secured	2035
2008	Pollution control bonds	$ 17	Variable	Secured	2036
2008	Pollution control bonds	$ 17	Variable	Secured	2036
2007	Pollution control bonds	$ 54	Variable	Secured	2024
2007	First mortgage bonds	$ 54	7.92%	Secured	2007

Issuances of long-term debt for 2008 and 2007 are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Due to Fidelia	$ 75	7.035%	Unsecured	2018
2008	Pollution control bonds	$ 78	Variable	Unsecured	2032
2008	Due to Fidelia	$ 50	6.16%	Unsecured	2018
2008	Due to Fidelia	$ 50	5.645%	Unsecured	2018
2008	Due to Fidelia	$ 75	5.85%	Unsecured	2023
2007	Pollution control bonds	$ 54	Variable	Unsecured	2034
2007	Pollution control bonds	$ 18	Variable	Unsecured	2026
2007	Pollution control bonds	$ 9	Variable	Unsecured	2037
2007	Due to Fidelia	$ 53	5.69%	Unsecured	2022
2007	Due to Fidelia	$ 75	5.86%	Unsecured	2037
2007	Due to Fidelia	$ 50	5.98%	Unsecured	2017
2007	Due to Fidelia	$ 100	5.96%	Unsecured	2028
2007	Due to Fidelia	$ 70	5.71%	Unsecured	2019
2007	Due to Fidelia	$ 100	5.45%	Unsecured	2014

In October 2008, KU issued Carroll County 2008 Series A tax exempt bonds in the amount of $78 million. The new bonds mature on February 1, 2032, and bear interest at a variable rate. The new bonds refinance four existing bonds (Carroll County 2005 Series A and C - $13 million each and the Carroll County 2006 Series A and C - $17 million each), and includes $18 million of new funding. The proceeds from the new funding will be held in escrow pending incurrence of qualifying expenditures.

In December 2008, KU converted the interest rate mode of the Carroll County 2006 Series B to a weekly mode from an auction mode. The bonds along with the Carroll County 2004 Series A, the Mercer County 2000 Series A, and the Carroll County 2008 Series A, were issued with the enhancement of a letter of credit. The bonds have been reclassified as current portion of long-term debt because investors can put the bonds back to the Company on a weekly basis.

In February 2007, KU completed a series of financial transactions impacting its periodic reporting requirements. The $54 million Pollution Control Series 10 bond was refinanced and replaced with a new unsecured tax-exempt bond of the same amount maturing in 2034. The $53 million Series P bond was defeased and replaced with an intercompany loan totaling $53 million from Fidelia. In conjunction with the defeasance, the Company terminated the related interest rate swap. Fidelia also agreed to eliminate the second lien on its two secured loans. Pursuant to the terms of the remaining tax-exempt bonds, the first mortgage bonds were cancelled and the underlying lien on substantially all of KU's assets was released following the completion of these steps. KU no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

Long-term debt maturities for KU are shown in the following table:

(in millions)	
2009	$ -
2010	33
2011	-
2012	50
2013	175
Thereafter	1,274 (a)
Total	$ 1,532

(a) Includes long-term debt of $228 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2023 to 2034.

Note 8 - Notes Payable and Other Short-Term Obligations

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2008	$ 400	$ 16	$ 384	1.49%
December 31, 2007	$ 400	$ 23	$ 377	4.75%

E.ON U.S. maintains revolving credit facilities totaling $313 million and $150 million at December 31, 2008 and 2007, respectively, to ensure funding availability for the money pool. At December 31, 2008, one facility, totaling $150 million, is with E.ON North America, Inc., while the remaining line, totaling $163 million, is with Fidelia; both are affiliated companies. The facility as of December 31, 2007, was with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2008	$ 313	$ 299	$ 14	2.05%
December 31, 2007	$ 150	$ 62	$ 88	4.97%

During June 2007, KU entered into a short-term bilateral line of credit totaling $35 million. During the third quarter of 2007, KU extended the maturity date on this facility to June 2012. There was no outstanding balance under this facility at December 31, 2008.

The covenants under this revolving line of credit include the following:

- The debt/total capitalization ratio must be less than 70%
- E.ON must own at least 66.667% of voting stock of KU directly or indirectly
- The corporate credit rating of the Company must be at or above BBB- and Baa3 as determined by S&P and Moody's
- A limitation on disposing of assets aggregating more than 15% of total assets as of December 31, 2006

KU was in compliance with these covenants at December 31, 2008.

In October 2008, KU closed on a new $78 million bilateral line of credit which has a 364 day maturity. This facility was terminated in December 2008 and replaced by four new letter of credit facilities to allow issuance of letters of credit totaling $198 million to support tax-exempt bonds totaling $195 million. The reimbursement agreements are identical and contain the following covenants:

- E.ON must own 75% of voting stock of KU directly or indirectly
- A limitation on disposing of assets aggregating more than 20% of total assets as of most recent quarter-end.

At December 31, 2008, KU had no remaining capacity for letters of credit under these facilities and was in compliance with these covenants.

Note 9 - Commitments and Contingencies

Operating Leases. KU leases office space, office equipment, plant equipment and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $9 million and $6 million for 2008 and 2007, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2008, are shown in the following table:

(in millions)	
2009	$ 9
2010	5
2011	4
2012	4
2013	3
Thereafter	6
Total	$ 31

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in this proceeding denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages.

In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding, pursuant to a July 2005 summary judgment ruling interpreting the contract termination provisions in OMU's favor.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in KU's favor, including determinations that KU's interpretation of facilities charge fund payments was accurate; that KU is the proportionate owner of NOx allowances allocated to the OMU plant by the government; that OMU's claims disputing various back-up power charges should be dismissed and that's KU's counterclaim based on operations and maintenance practices should proceed to trial. The summary judgment rulings resulted in the dismissal of all of OMU's remaining claims against KU. The trial on KU's counterclaim occurred during October and November 2008. During February 2009, the court issued orders on the matters covered at trial, including (i) awarding KU an aggregate $9 million relating to the cost of NOx allowances charged by OMU to KU and the price of back-up power purchased by OMU from KU and (ii) denying KU's claim for damages based upon sub-par operations and availability of the OMU units. Those rulings, as well as all of the court's various prior rulings, including upholding early termination of the contract in spring 2010, remain subject to post-trial motions and appeal rights.

Sale and Leaseback Transaction. KU is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. KU and LG&E have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if KU had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

In case of default under the lease, KU is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2008, the maximum aggregate amount of default fees or amounts was $9 million, of which KU would be responsible for 62% (approximately $6 million). KU has made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay KU's full portion of any default fees or amounts.

Letter of Credit. KU has provided letters of credit totaling $198 million supporting bonds of $195 million and a letter of credit totaling less than $1 million to support certain obligations related to workers' compensation.

Purchased Power. KU has purchased power arrangements with OMU and OVEC. Under the OMU agreement, which is presently expected to end in May 2010, KU purchases all of the output of an approximately 400-Mw coal-fired generating station not required by OMU. The amount of purchased power available to KU during 2009-2010, which is expected to be approximately 5% of KU's total Kwh native load energy requirements, is dependent upon a number of factors including the OMU units' availability, maintenance schedules, fuel costs and OMU requirements. Payments are based on the total costs of the station allocated per terms of the OMU agreement. Included in the total costs is KU's proportionate share of debt service requirements on $228 million of OMU bonds outstanding at December 31, 2008. The debt service is allocated to KU based on its annual allocated share of capacity, which averaged approximately 41% in 2008. KU does not guarantee the OMU bonds, or any requirements therein, in the event of default by OMU.

KU has a contract for purchased power with OVEC, terminating in 2026, for various Mw capacities. KU has an investment of 2.5% ownership in OVEC's common stock, which is accounted for on the cost method of accounting. KU's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity. Future obligations for power purchases are shown in the following table:

(in millions)	
2009	$ 26
2010	17
2011	10
2012	10
2013	10
Thereafter	155
Total	$ 228

Coal and Gas Purchase Obligations. KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

(in millions)	
2009	$ 442
2010	387
2011	363
2012	217
2013	59
Thereafter	- (a)
Total	$ 1,468

(a) Obligations after 2013 are indexed to future market prices and will not be included above until prices are set using the contracted methodology.

Construction Program. KU had $123 million of commitments in connection with its construction program at December 31, 2008.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights. The parties have commenced certain negotiations relating to potential construction cost increases due to higher labor and per diem costs above an established baseline, and certain safety and compliance costs resulting from a change in law. KU's share of additional costs from inception of the contract through the expected project completion in 2010 may be approximately $25 million.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendency of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an Order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ revised the permit to address the issues identified in the EPA's Order, although the Sierra Club subsequently submitted comments objecting to the revisions. Although the Company does not expect material changes in the permit as a result of the various petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Mine Safety Compliance Costs. In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky and other states that supply coal to KU, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of some of the coal contracts KU has in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. KU has begun to receive information from the mines it contracts with regarding price adjustments related to these compliance costs and has hired a consultant to review all supplier claims for validity and reasonableness. At this time KU has not been notified of claims by all mines and is reviewing those claims it has received. An adjustment will be made to the value of the coal inventory once the amount is determinable, however, the amount cannot be estimated at this time. The Company expects to recover these costs through the FAC.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, KU is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation, but leaving the CAIR in the interim. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. KU is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and KU's and LG&E's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has announced that it intends to promulgate a new rule to replace the CAMR. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new mercury reduction rules with different or more stringent requirements. Kentucky has also repealed its corresponding state mercury regulations. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the

CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2008 time period at a cost of $221 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $720 million during the 2009 through 2011 time period for pollution controls including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by the Company for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring on-going efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is also monitoring on-going regulatory proceedings including the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. The new administration has announced its intention to exercise its existing authority under the Clean Air Act to achieve reductions in GHG emissions. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint sought civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. In December 2008, the Company reached a tentative settlement with the government resolving all outstanding claims. The proposed consent decree provides for payment of a $1 million civil penalty; funding of $3 million in environmental mitigation projects; surrender of 53,000 excess SO_2 allowances; surrender of excess NOx allowances estimated at 650 allowances annually for eight years; installation of an FGD by December 31, 2010; installation of an SCR by December 31, 2012; and compliance with specified emission limits and operational restrictions. In February 2009, the proposed consent decree was lodged with the Court. In March 2009, the Court issued a consent decree approving the settlement.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. KU and LG&E have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation activities for elevated PCB levels at existing properties, liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 10 - Jointly Owned Electric Utility Plant

KU and LG&E have begun construction of TC2, a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively, in TC2. Of the remaining 25% of TC2, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is expected to occur in 2010. In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	107	455	97	91	750

(in millions)			
KU's 60.75% ownership:		LG&E's 14.25% ownership:	
Cost	$ 560	Cost	$ 136
Accumulated depreciation	-	Accumulated depreciation	2
Net book value	$ 560	Net book value	$ 134

	KU	LG&E
Construction work in progress (included in above)	$550	$132

KU and LG&E jointly own the following CTs and related equipment:

($ in millions)	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
KU 47%, LG&E 53% (a)	129	53	(12)	41	146	62	(15)	47	275	115	(27)	88
KU 62%, LG&E 38% (b)	190	82	(14)	68	118	51	(8)	43	308	133	(22)	111
KU 71%, LG&E 29% (c)	228	80	(18)	62	92	32	(6)	26	320	112	(24)	88
KU 63%, LG&E 37% (d)	404	137	(21)	116	236	79	(12)	67	640	216	(33)	183
KU 71%, LG&E 29% (e)	n/a	9	(2)	7	n/a	3	(1)	2	n/a	12	(3)	9

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.
(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on its respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Electric operating revenues from LG&E	$ 80	$ 46
Purchased power from LG&E	109	93

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest income and expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Interest on money pool loans	$ 2	$ 6
Interest on Fidelia loans	56	35

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. Services on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU for the years ended December 31, were as follows:

(in millions)	2008	2007
E.ON U.S. Services billings to KU	$ 227	$ 488
KU billings to LG&E	75	6
LG&E billings to KU	5	12
KU billings to E.ON U.S. Services	3	26

In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

In March, June, September and December 2008, KU received capital contributions from its common shareholder, E.ON U.S., in the amounts of $25 million, $50 million, $50 million and $20 million, respectively.

In September and December 2007, KU received capital contributions from its shareholder, E.ON U.S. in the amount of $55 million and $20 million, respectively.

Note 12 – Subsequent Events

On January 13, 2009, KU, the AG, KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, KU's base electric rates will decrease by $9 million annually. An Order approving the settlement was received on February 5, 2009. The new rates were implemented effective February 6, 2009. However, in connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit, respectively, terminated, which will amount in increased revenues of approximately $16 million annually.

On January 27 and 28, 2009, a significant winter ice storm passed through KU's service territory causing approximately 199,000 customer outages, followed closely by a severe wind storm on February 11, 2009, causing approximately 44,000 customer outages. KU currently estimates costs incurred of $66 million of expenses and $28 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

On February 19, 2009, the court issued post-trial orders in the litigation between KU and OMU, which orders awarded KU an aggregate $9 million related to disputed NOx allowance and back-up power pricing provisions, but denied a KU claim for damages relating to the availability of the OMU units. The orders are subject to certain appeal and other procedural rights prior to becoming final.

On March 17, 2009, the Court issued a consent decree approving the settlement in the Brown New Source Review litigation.

On March 19, 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial position or results of operations.

FINANCIAL STATEMENTS

MARCH 31, 2008

Louisville Gas and Electric Company

Financial Statements and Additional Information

As of March 31, 2008 and 2007

INDEX OF ABBREVIATIONS

ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
Company	LG&E
DSM	Demand Side Management
ECR	Environmental Cost Recovery
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EUSIC	E.ON US Investments Corp.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation Number
GHG	Greenhouse Gas
GSC	Gas Supply Clause
IRS	Internal Revenue Service
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offer Rate
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Units
Moody's	Moody's Investor Services, Inc.
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
S&P	Standard & Poor's Rating Service
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2

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Financial Statements (Unaudited)

Louisville Gas and Electric Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
OPERATING REVENUES:		
Electric	$ 224	$ 222
Gas	191	153
Total operating revenues	415	375
OPERATING EXPENSES:		
Fuel for electric generation	80	76
Power purchased	24	26
Gas supply expenses	153	115
Other operation and maintenance expenses	80	69
Depreciation and amortization	31	31
Total operating expenses	368	317
OPERATING INCOME	47	58
Other expense – net	2	2
Interest expense (Notes 3 and 6)	8	5
Interest expense to affiliated companies (Note 9)	6	3
INCOME BEFORE INCOME TAXES	31	48
Federal and state income taxes (Note 5)	10	16
NET INCOME	$ 21	$ 32

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Balance at beginning of period	$ 690	$ 639
Net income	21	32
Subtotal	711	671
Cash dividends declared on stock:		
Cumulative preferred	-	1
Common	40	35
Subtotal	40	36
Balance at end of period	$ 671	$ 635

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	March 31, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 3	$ 4
Restricted cash	2	7
Accounts receivable – less reserves of $2 million as of March 31, 2008 and December 31, 2007	179	189
Accounts receivable from affiliated companies (Note 9)	5	-
Materials and supplies:		
Fuel (predominantly coal)	37	46
Gas stored underground	23	81
Other materials and supplies	31	31
Reacquired bonds	40	-
Prepayments and other current assets (Note 9)	5	13
Total current assets	325	371
Utility plant:		
At original cost	4,364	4,319
Less: reserve for depreciation	1,645	1,619
Net utility plant	2,719	2,700
Deferred debits and other assets:		
Restricted cash	13	12
Prepaid pension assets	15	14
Regulatory assets (Note 2):		
Pension and postretirement benefits	109	110
Other	92	94
Other assets	11	12
Total deferred debits and other assets	240	242
Total assets	$ 3,284	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	March 31, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 160	$ 120
Notes payable to affiliated companies (Notes 6 and 9)	108	78
Accounts payable	107	111
Accounts payable to affiliated companies (Note 9)	18	57
Customer deposits	20	19
Other current liabilities	32	34
Total current liabilities	445	419
Long-term debt:		
Long-term debt (Note 6)	414	454
Long-term debt to affiliated company (Notes 6 and 9)	410	410
Total long-term debt	824	864
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	341	342
Accumulated provision for pensions and related benefits (Note 4)	95	94
Investment tax credit (Note 5)	46	46
Asset retirement obligation	30	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	244	241
Deferred income taxes – net	49	50
Gas supply adjustment and other	16	19
Long-term derivative liability	29	22
Other liabilities	26	25
Total deferred credits and other liabilities	876	869
Common equity:		
Common stock, without par value –		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	60	60
Accumulated other comprehensive loss	(16)	(13)
Retained earnings	671	690
Total common equity	1,139	1,161
Total liabilities and equity	$ 3,284	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Three Months Ended March 31, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 21	32
Items not requiring cash currently:		
Depreciation and amortization	31	31
Deferred income taxes – net	(1)	1
Other	(3)	2
Changes in current assets and liabilities:		
Accounts receivable	5	29
Material and supplies	67	48
Accounts payable	(22)	2
Accrued income taxes	-	5
Prepayments and other current assets	8	-
Other current liabilities	(2)	3
Pension and postretirement funding	1	(56)
Gas supply clause receivable, net	(8)	(23)
Other	8	10
Net cash provided by operating activities	105	84
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(67)	(34)
Restricted cash	5	(7)
Net cash used for investing activities	(62)	(41)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Short-term borrowings from affiliated company	355	197
Repayment of short-term borrowings from affiliated company	(325)	(241)
Reacquired bonds	(40)	-
Payment of dividends	(40)	(1)
Long-term derivative liability	7	1
Restricted cash	(1)	-
Net cash used in financing activities	(44)	(44)
CHANGE IN CASH AND CASH EQUIVALENTS	(1)	(1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4	7
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 3	$ 6

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2008	2007
Net income	$ 21	$ 32
Loss on derivative instruments and hedging activities – net of tax benefit/(expense) of $2 million and $(1) million, respectively (Note 3)	(3)	-
Other comprehensive loss, net of tax	(3)	-
Comprehensive income	$ 18	$ 32

The accompanying notes are an integral part of these financial statements.

Note 1 - General

The unaudited financial statements include the accounts of the Company. LG&E's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings, comprehensive income and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted, although the Company believes that the disclosures are adequate to make the information presented not misleading. These unaudited financial statements and notes should be read in conjunction with the Company's annual report for the year ended December 31, 2007, including management's discussion and analysis and the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No.

159 was adopted effective January 1, 2008 and had no impact on the statements of operations, financial position and cash flows.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, the Company will provide additional disclosures relating to its financial derivatives, AROs and pension assets, as required, in 2008.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to LG&E's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

Louisville Gas and Electric Company
(unaudited)

(in millions)	March 31, 2008	December 31, 2007
ARO	$ 25	$ 24
Unamortized loss on bonds	20	19
GSC adjustments	23	20
MISO exit	12	13
FAC	3	9
ECR	4	4
Other	5	5
Subtotal	92	94
Pension and postretirement benefits	109	110
Total regulatory assets	$ 201	$ 204
Accumulated cost of removal of utility plant	$ 244	$ 241
Deferred income taxes – net	49	50
Gas supply adjustments ($5 and $10 million at March 31, 2008 and December 31, 2007, respectively) and other	16	19
Total regulatory liabilities	$ 309	$ 310

LG&E does not currently earn a rate of return on the GSC adjustments, FAC and gas performance-based ratemaking regulatory assets, all of which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset which represents the changes in funded status of the plans. The Company will seek recovery of this asset in future proceedings with the Kentucky Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. LG&E will seek recovery of this asset in future proceedings with the Kentucky Commission. LG&E currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit, gas performance-based ratemaking and Mill Creek Ash Pond costs. Other regulatory liabilities include DSM and MISO costs included in base rates that will be netted against costs of withdrawing from the MISO in the next rate case.

MISO Exit. LG&E and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, LG&E paid approximately $13 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. LG&E and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided LG&E with an immediate recovery of less than $1 million and will provide an estimated $2 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which may continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in LG&E's next rate case, however, the Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In January 2008, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period May 1, 2007 through October 31, 2007. A public hearing was held in March 2008. An order is anticipated in the third quarter of 2008.

In August 2007, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period of November 1, 2006 through April 30, 2007. A public hearing was held in October 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

ECR. In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of LG&E's environmental surcharge. All parties to the case submitted requests with the Kentucky Commission to waive rights to a hearing on this matter. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review period, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Other Regulatory Matters

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by LG&E and KU, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005, and was never appealed.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into

Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, LG&E, KU and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. LG&E, KU and the Kentucky Commission filed for reconsideration of the appellate court's ruling, but those requests were denied in April 2008. LG&E and KU will file a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line (all rights of way for the other line have been acquired), a Meade County, Kentucky circuit court judge issued a ruling upholding the objections of two co-owners of the property crossed by the easement and dismissed that eminent domain proceeding pending the completion of the CCN appeal described above. LG&E and KU have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the eminent domain litigation. Additional condemnation proceedings involving other parcels of property to support this same transmission line are also pending in neighboring Hardin County, and three landowners there have now sought dismissal of certain of those proceedings in Hardin County, on the same grounds cited by the Meade County court. LG&E and KU have opposed those efforts to dismiss, and are awaiting ruling by the Hardin County Circuit Court.

Merger Surcredit. In December 2007, LG&E submitted to the Kentucky Commission its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. The Kentucky Commission issued a procedural schedule for this proceeding in March 2008, with data discovery to be completed in May 2008. A public hearing is scheduled in May 2008, and an order is expected by the end of the second quarter of 2008.

DSM. In July 2007, LG&E and KU filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. LG&E and KU filed revised tariffs in April 2008, under authority of this Order.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the Electric Reliability Organization, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. LG&E is a member of the SERC, which acts as LG&E's RRO. The SERC is currently assessing LG&E's compliance with certain existing mitigation plans resulting from a prior RRO's audit of various reliability standards, and LG&E and SERC are in discussions regarding potential settlement, further mitigation steps or other resolution actions regarding these items. While LG&E believes itself to be in substantial compliance with the mandatory reliability standards, LG&E cannot predict the outcome of the current SERC proceeding or of other analysis which may be conducted regarding compliance with particular reliability standards.

Depreciation Study. In December 2007, LG&E filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received by the Kentucky Commission, the timing of which cannot currently be determined.

Brownfield Development Rider Tariff. In March 2008, LG&E and KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. Data discovery concluded in July 2007, and no parties to the case requested a hearing. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by LG&E, for implementation within approximately eight months, for its large commercial and industrial customers.

Collection Cycle Revision. In September 2007, LG&E filed an application with the Kentucky Commission to revise the collection cycle for customer bill payments from 15 days to 10 days to more closely align with the KU billing cycle and to avoid confusion for delinquent customers. In December 2007, the Kentucky Commission denied LG&E's request to shorten the collection cycle. LG&E filed a motion with the Kentucky Commission for reconsideration and received an Order granting approval. The Kentucky Commission issued additional data requests to LG&E in February 2008. An order is anticipated in the second quarter of 2008.

Note 3 - Financial Instruments

Effective January 1, 2008, LG&E adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157.

Interest Rate Swaps (hedging derivatives). LG&E uses over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. The fair values of the swaps reflect price quotes from dealers. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature. Management has designated all of the interest rate swaps as hedge instruments. Financial instruments designated as cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity.

The following table sets forth by level within the fair value hierarchy LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2008. There are no Level 2 or Level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1
Liabilities:	
Interest rate swaps	$29
Total	$29

LG&E was party to various interest rate swap agreements with aggregate notional amounts of $211 million as of March 31, 2008 and December 31, 2007. Under these swap agreements, LG&E paid fixed rates averaging 4.38% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 2.16% at March 31, 2008. The swap agreements in effect at March 31, 2008, have been designated as cash flow hedges and mature on dates ranging from 2020 to 2033. The cash flow designation was assigned because the underlying variable rate debt has variable future cash flows. LG&E's hedges have been determined to be highly effective. For the three months ended March 31, 2008, the Company recorded a pre-tax loss of $6 million in other comprehensive income to reflect the ineffective portion of the hedge. Amounts in accumulated other comprehensive income will be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million. A deposit in the amount of $13 million, used as collateral for one of the interest rate swaps, is classified as restricted cash on the balance sheet. The amount of the deposit required is tied to the market value of the swap.

Energy Trading and Risk Management Activities (non-hedging derivatives). LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

The table below summarizes LG&E's energy trading and risk management activities for the three months ended March 31, 2007:

(in millions)	
Fair value of contracts at beginning of period, net asset	$ 1
Unrealized gains and losses recognized at contract inception during the period	-
Realized gains and losses recognized during the period	-
Changes in fair values attributable to changes in valuation techniques and assumptions	(2)
Other unrealized gains and losses and changes in fair values	-
Fair value of contracts at end of period, net (liability) asset	$ (1)

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at March 31, 2007, had a maturity of less than one year. There were no contracts outstanding at March 31, 2008. All amounts for 2008 are less than $1 million. Energy trading and risk management contracts are valued using Level 1, prices actively quoted for proposed or executed transactions or quoted by brokers.

Note 4 - Pension and Other Postretirement Benefit Plans

The following table provides the components of net periodic benefit cost for pension and other benefit plans for the three months ended March 31:

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Service cost	$ 1	$ 1	$ -	$ -
Interest cost	6	8	1	1
Expected return on plan assets	(7)	(11)	-	-
Amortization of prior service costs	1	2	1	1
Amortization of actuarial loss	-	1	-	-
Benefit cost year-to-date	$ 1	$ 1	$ 2	$ 2

Net periodic benefit costs incurred by employees of LG&E are reflected in both utility plant on the balance sheet and in operating expense on the income statement. The above costs do not include allocations of net periodic benefit costs from affiliates whose employees provide services to LG&E.

The pension plans are funded in accordance with all applicable requirements of the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. In March 2008, LG&E made contributions to other postretirement benefit plans of approximately $2 million. LG&E anticipates making further voluntary contributions in 2008 to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the postretirement medical account under the pension plan up to the maximum amount allowed by law.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including LG&E, will calculate its separate income tax for the tax period. The resulting separate-return tax cost or benefit will be paid to or received from the parent company, or its designee. LG&E also files income tax returns in various state jurisdictions. With few exceptions, LG&E is no longer subject to U.S. federal income tax examinations for years before 2004. Statutes of limitations related to 2004 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to the actual calendar year applicable to the return and ends 90 days after the return is filed.

LG&E adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, LG&E had $1 million of unrecognized tax benefits related to federal and state income taxes. If recognized, the entire $1 million of unrecognized tax benefits would reduce the effective income tax rate.

Possible amounts of uncertain tax positions for LG&E that may decrease within the next 12 months total less than $1 million, and are based on the expiration of statutes during 2008.

LG&E, upon adoption of FIN 48, adopted a new financial statement classification for interest and penalties. Prior to the adoption of FIN 48, LG&E recorded interest and penalties for income taxes on the income statement in income tax expense and in the taxes accrued balance sheet account, net of tax. Upon adoption of FIN 48, interest is recorded as interest expense and penalties are recorded as operating expenses on the income statement and accrued expenses in the balance sheets, on a pre-tax basis. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes.

The amount LG&E recognized as interest accrued related to unrecognized tax benefits in interest expense in operating expenses was less than $1 million at March 31, 2008 and March 31, 2007. At the date of adoption, LG&E accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by LG&E upon adoption of FIN 48, or through March 31, 2008.

In June 2006, LG&E and KU filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that LG&E and KU were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credit. LG&E's portion of the TC2 tax credit will be approximately $25 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, LG&E recorded investment tax credits of $1 million and $3 million during the three months ended March 31, 2008 and March 31, 2007, respectively, decreasing current federal income taxes.

In March 2008, certain groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was violative of certain environmental laws and demanded relief, including suspension or termination of the program. LG&E is monitoring, but is not currently a party to, this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 - Short-Term and Long-Term Debt

LG&E's long-term debt includes $160 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Jefferson County Series 2001 A and B, Trimble County Series 2001 A and B and Jefferson County Series 2005 A. Maturity dates for these bonds range from 2026 to 2035. LG&E does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the three months ended March 31, 2008, was 3.23%.

During June 2007, LG&E's five existing lines of credit totaling $185 million expired and were replaced with short-term bilateral lines of credit facilities totaling $125 million. There was no outstanding balance under any of these facilities at March 31, 2008. During the third quarter of 2007, LG&E extended the maturity date of these facilities through June 2012.

Pollution control series bonds are obligations of LG&E issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during April 2007, the county's debt was also secured by an equal amount of LG&E's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless LG&E defaults on the loan agreement.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At March 31, 2008, LG&E had an aggregate $574 million of outstanding pollution control indebtedness, of which $354 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" where there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the three months ended March 31, 2008 and March 31, 2007, the average rate on the auction rate bonds was 4.82% and 3.65%, respectively. The instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first quarter of 2008, the ratings of the Louisville Metro 2003 Series A bonds were downgraded from Aaa to A2 by Moody's and from AAA to A- by S&P due to downgrades of the bond insurer. In February 2008, LG&E issued a notice to bondholders of its intention to convert the Louisville Metro 2005 Series A, 2007 Series A and B bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. These conversions were completed in March 2008, for the 2005 Series and in April 2008, for the two 2007 Series. In connection with the conversions, LG&E purchased the bonds from the remarketing agent. In March 2008, LG&E issued notices to bondholders of its intention to convert the Jefferson County 2000 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in May 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent. LG&E will hold some or all of such bonds until a later date, including potential further conversion, remarketing or refinancing. Uncertainty in markets relating to auction rate securities or steps LG&E has taken or may take to mitigate such uncertainty, such as additional conversions, subsequent restructurings or redemption and refinancing, could result in LG&E incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures. See Note 10, Subsequent Events.

LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances were as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
March 31, 2008	$400	$108	$292	3.08%
December 31, 2007	$400	$78	$322	4.75%

E.ON U.S. maintains a revolving credit facility totaling $311 million at March 31, 2008 and $150 million at December 31, 2007, with an affiliated company, E.ON North America, Inc., to ensure funding availability for the money pool. The balance is as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
March 31, 2008	$311	$94	$217	3.36%
December 31, 2007	$150	$62	$88	4.97%

There were no redemptions or issuances of long-term debt year-to-date through March 31, 2008.

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in LG&E's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of LG&E contained therein). See the above-referenced notes in LG&E's Annual Report regarding such commitments or contingencies.

Construction Program. LG&E had approximately $105 million of commitments in connection with its construction program at March 31, 2008.

In June 2006, LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division for Air Quality in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, LG&E administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the Kentucky Division for Air Quality issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. LG&E's operations are subject to a number of environmental laws and regulations, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to LG&E's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. The final rule is currently under challenge. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. LG&E's weighted-average company-wide emission rate for SO_2 in the first quarter of 2008 was approximately 0.51 lbs./MMBtu of heat input, with every generating unit below its emission limit established by the Kentucky Division for Air Quality and the Louisville Metro Air Pollution Control District. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. In February 2008, a federal appellate court issued a decision vacating the CAMR, but the EPA and other parties have filed a motion for rehearing. Depending on the final outcome of the pending appeal, the CAMR could be superceded by new mercury reduction rules with different or more stringent requirements. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAMR, but those state requirements are likely to be revised to reflect the outcome of the challenge to the CAMR at the federal level. In addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants, but those rules are not expected to have a material impact on LG&E's power plant operations.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 through 2007 time period at a cost of $197 million. In 2001, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E under its periodic environmental surcharge mechanisms. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve the emissions reductions mandated by the CAIR, LG&E expects to incur additional capital expenditures totaling $130 million during the 2008 through 2010 time period for pollution control equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by LG&E for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. LG&E is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of LG&E, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. The Companies have complied with the information requests and are not able to predict further proceedings in this matter at this time.

General Environmental Proceedings. From time to time, LG&E appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation obligations for former manufactured gas plant sites; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; ongoing claims regarding alleged particulate emissions from LG&E's Cane Run station and ongoing claims regarding GHG emissions from LG&E's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of LG&E.

Note 8 - Segments of Business

LG&E's revenues, net income and total assets by business segment for the three months ended March 31 follow:

	Three Months Ended March 31,	
(in millions)	2008	2007
LG&E Electric		
Revenues	$ 224	$ 222
Net income	11	21
Total assets	2,680	2,570
LG&E Gas		
Revenues	191	153
Net income	10	11
Total assets	604	553
Total		
Revenues	415	375
Net income	21	32
Total assets	3,284	3,123

Note 9 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as electric operating revenues and purchased power operating expense. LG&E intercompany electric revenues and purchased power expense for the three months ended March 31, were as follows:

(in millions)	2008	2007
Electric operating revenues from KU	$27	$30
Purchased power from KU	14	18

Interest Charges

See Note 6, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

LG&E's intercompany interest expense for the three months ended March 31, was as follows:

(in millions)	2008	2007
Interest on money pool loans	$ 1	$ 1
Interest on Fidelia loans	5	3

Other Intercompany Billings

E.ON U.S. Services provides LG&E with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E and vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services is directly charged to LG&E, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned combustion turbines and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of LG&E, primarily tax settlements, and other payments made by LG&E on behalf of other non-regulated businesses which are paid through E.ON U.S. Services.

Intercompany billings to and from LG&E for the three months ended March 31 were as follows:

(in millions)	2008	2007
E.ON U.S. Services billings to LG&E	$42	$123
LG&E billings to KU	1	10
KU billings to LG&E	23	14
LG&E billings to E.ON U.S. Services	3	1

In March 2008, LG&E paid a dividend of $40 million to its common shareholder, E.ON U.S. LLC.

Note 10 - Subsequent Events

On April 4, 2008, the 2007 Series A and B bonds were converted from an auction rate mode to a weekly interest rate mode. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

On May 1, 2008, the 2000 Series A bonds were converted from an auction rate mode to a weekly interest rate mode. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during the three month period ended March 31, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of December 31, 2007, LG&E provided natural gas to approximately 326,000 customers and electricity to approximately 401,000 customers in Louisville and adjacent areas in Kentucky. LG&E's service area covers approximately 700 square miles in 17 counties. LG&E also provides natural gas service in limited additional areas. LG&E's coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions, produce most of LG&E's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

LG&E is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making LG&E an indirect wholly-owned subsidiary of E.ON. LG&E's affiliate, KU, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

Environmental Matters

Protection of the environment is a major priority for LG&E. Federal, state and local regulatory agencies have issued LG&E permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric and gas utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Net Income

Net income for the three months ended March 31, 2008, decreased $11 million compared to the same period in 2007. The decrease was primarily the result of increased operating expenses ($51 million) and increased interest expense ($6 million), partially offset by increased revenues ($40 million) and decreased income taxes ($6 million), attributable to a decreased pre-tax income.

Revenues

Electric revenues in the three months ended March 31, 2008, increased $2 million primarily due to:

- Increased fuel costs ($5 million) billed to customers through the FAC due to higher fuel costs (coal and natural gas) and higher transportation costs
- Increased ECR surcharge ($2 million) due to increased recoverable capital spending
- Decreased wholesale sales ($5 million) due to increased native load demand

Natural gas revenues in the three months ended March 31, 2008, increased $38 million primarily due to:

- Increased average cost of gas billed to retail customers ($23 million) due to higher gas expenses
- Increased volumes ($17 million), resulting from an 8% increase in heating degree days in the first quarter of 2008 as compared to the same period in 2007
- Decreased wholesale sales ($2 million)

Expenses

Fuel for electric generation and natural gas supply expenses comprise a large component of total operating expenses. Increases or decreases in the cost of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission and the FERC.

Fuel for electric generation increased $4 million in the three months ended March 31, 2008, primarily due to:

- Increased spot market pricing for coal/natural gas ($7 million) due to mine safety compliance costs and higher transportation costs
- Decreased generation ($3 million) due to lower wholesale sales

Power purchased expense decreased $2 million in the three months ended March 31, 2008, primarily due to:

- Decreased volumes purchased ($5 million) due to lower intercompany purchases and higher native load
- Increased cost per mWh of purchases ($3 million) due to higher fuel prices

Gas supply expenses increased $38 million in the three months ended March 31, 2008, primarily due to:

- Increased cost of net gas supply ($29 million) due to higher inventory unit cost and adjustments to the GSC for recoveries
- Increased volumes of natural gas delivered to the distribution system ($9 million) due to higher demand

Other operation and maintenance expenses increased $11 million in the three months ended March 31, 2008, primarily due to increased maintenance expenses ($9 million) and increased other operation expenses ($2 million).

Maintenance expense increased $9 million in the three months ended March 31, 2008, primarily due to:

- Increased boiler maintenance expense ($5 million) due to spring outages
- Increased electric maintenance ($2 million) due to major inspection work
- Increased contractor and overtime labor ($2 million) related to storm restoration

Other operation expense increased $2 million in the three months ended March 31, 2008, primarily due to:

- Increased scrubber reactant expense ($1 million) due to higher priced lime contract
- Increased labor expense ($1 million) resulting from storm restoration

Interest expense, including interest expense to affiliated companies, increased $6 million in the three months ended March 31, 2008, primarily due to:

- Increased interest expense ($3 million) due to increased variable rates on pollution control bonds
- Increased interest expense to affiliated companies ($3 million) due to increased borrowings from affiliated companies

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.7	3.3
Reserve release	0.0	(0.2)
Amortization of investment tax credits	(3.2)	(2.1)
Other differences	(2.3)	(2.7)
Effective income tax rate	32.2%	33.3%

The effective income tax rate decreased for the three months ended March 31, 2008, compared to the three months ended March 31, 2007, due primarily to a decrease in state income taxes net of federal benefit due to an increase in state coal credits and a decrease in amortization of investment tax credits due to the changes in levels of pretax income.

Liquidity and Capital Resources

LG&E uses net cash generated from its operations and external financing (including financing from affiliates) to fund construction of plant and equipment and the payment of dividends. LG&E believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was $105 million and $84 million for the three months ended March 31, 2008 and 2007, respectively.

The 2008 increase of $21 million was primarily the result of increases in cash due to changes in:

- Pension and post retirement funding ($57 million) due to higher pension funding in 2007
- Materials and supplies ($19 million)
- Gas supply clause receivable ($15 million)
- Prepayments and other current assets ($8 million)

These increases were partially offset by cash used by changes in:

- Accounts payable ($24 million)
- Accounts receivable ($24 million)
- Earnings, net of non-cash items ($18 million)
- Other current liabilities ($5 million)
- Accrued income taxes ($5 million)
- Other ($2 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $67 million and $34 million in the three months ended March 31, 2008 and 2007, respectively. Net cash used for investing activities decreased $21 million in the three months ended March 31, 2008 compared to 2007, due to decreased capital expenditures of $33 million and increased restricted cash of $12 million. Restricted cash represents the escrowed proceeds of the Pollution Control Bonds issued which are disbursed as qualifying costs are incurred.

Financing Activities

Net cash outflows from financing activities were $44 million in the three months ended March 31, 2008 and 2007, respectively.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

LG&E expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $735 million, consisting primarily of construction of TC2 totaling approximately $85 million (including $25 million for environmental controls), gas main replacement initiatives of approximately $50 million, redevelopment of the Ohio Falls hydroelectric facility totaling approximately $45 million, a customer care system totaling approximately $30 million and on-going construction related to generation and distribution assets.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

LG&E has a variety of funding alternatives available to meet its capital requirements. LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds of up to $400 million available to LG&E at market-based rates. Fidelia also provides long-term intercompany funding to LG&E. See Note 6 of Notes to Financial Statements.

LG&E's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See Note 7 of Notes to Financial Statements for current commitments. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In

November 2007, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds.

LG&E's debt ratings as of March 31, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework . The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company's internal control over financial reporting that occurred during the quarter ended March 31, 2008, that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting.

LG&E is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Legal Proceedings

For a description of the significant legal proceedings involving LG&E, reference is made to the information under the following captions of LG&E's Annual Report for the year ended December 31, 2007: Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in LG&E's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, LG&E believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on LG&E's financial position or results of operations.

FINANCIAL STATEMENTS

JUNE 30, 2008

Louisville Gas and Electric Company

Financial Statements and Additional Information

As of June 30, 2008 and 2007

INDEX OF ABBREVIATIONS

ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
Company	Louisville Gas and Electric Company
DSM	Demand Side Management
ECR	Environmental Cost Recovery
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EUSIC	E.ON US Investments Corp.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation Number
GHG	Greenhouse Gas
GSC	Gas Supply Clause
IRS	Internal Revenue Service
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offer Rate
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Units
Moody's	Moody's Investor Services, Inc.
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxide
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
S&P	Standard & Poor's Rating Service
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process

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Louisville Gas and Electric Company
Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Balance at beginning of period	$ 671	$ 635	$ 690	$ 639
Net income	19	24	40	56
Preferred stock buyback	-	(4)	-	(4)
Subtotal	690	655	730	691
Cash dividends declared on stock:				
Cumulative preferred	-	-	-	1
Common	-	30	40	65
Subtotal	-	30	40	66
Balance at end of period	$ 690	$ 625	$ 690	$ 625

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	June 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 3	$ 4
Restricted cash	11	7
Accounts receivable – less reserves of $2 million as of June 30, 2008 and December 31, 2007	153	189
Accounts receivable from affiliated companies (Note 9)	11	-
Materials and supplies:		
Fuel (predominantly coal)	42	46
Gas stored underground	40	81
Other materials and supplies	31	31
Prepayments and other current assets (Note 9)	14	13
Total current assets	305	371
Utility plant:		
At original cost	4,402	4,319
Less: reserve for depreciation	1,664	1,619
Net utility plant	2,738	2,700
Deferred debits and other assets:		
Restricted cash	12	12
Prepaid pension assets	15	14
Regulatory assets (Note 2):		
Pension and postretirement benefits	109	110
Other	109	94
Other assets	9	12
Total deferred debits and other assets	254	242
Total assets	$3,297	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	June 30, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 120	$ 120
Notes payable to affiliated companies (Notes 6 and 9)	188	78
Accounts payable	114	111
Accounts payable to affiliated companies (Note 9)	32	57
Customer deposits	21	19
Other current liabilities	41	34
Total current liabilities	516	419
Long-term debt:		
Long-term debt (Note 6)	323	454
Long-term debt to affiliated company (Notes 6 and 9)	410	410
Total long-term debt	733	864
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	352	342
Accumulated provision for pensions and related benefits (Note 4)	98	94
Investment tax credit (Note 5)	48	46
Asset retirement obligation	30	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	246	241
Deferred income taxes – net	47	50
Gas supply adjustment and other	18	19
Long-term derivative liability	22	22
Other liabilities	24	25
Total deferred credits and other liabilities	885	869
Common equity:		
Common stock, without par value –		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	60	60
Accumulated other comprehensive loss	(11)	(13)
Retained earnings	690	690
Total common equity	1,163	1,161
Total liabilities and equity	$ 3,297	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Six Months Ended June 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 40	$ 56
Items not requiring cash currently:		
Depreciation and amortization	63	63
Deferred income taxes – net	7	3
Investment tax credit – net	2	3
Other	9	7
Changes in current assets and liabilities:		
Accounts receivable	31	20
Material and supplies	45	46
Accounts payable	(9)	2
Other current liabilities	(4)	(21)
Pension funding	-	(56)
Gas supply clause receivable, net	(23)	(27)
Other	7	(4)
Net cash provided by operating activities	168	92
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(118)	(87)
Asset transferred to affiliate (Note 9)	10	-
Change in restricted cash	-	-
Long-term derivative liability (non-hedging) (Note 3)	1	-
Net cash used for investing activities	(107)	(87)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings from affiliated company (Note 6)	-	138
Short-term borrowings from affiliated company - net (Note 6)	110	19
Reacquired bonds	(131)	-
Retirement of first mortgage bonds	-	(126)
Issuance of pollution control bonds	-	126
Retirement of preferred stock	-	(91)
Payment of dividends	(40)	(69)
Long-term derivative liability (hedging) (Note 3)	(1)	(4)
Net cash used in financing activities	(62)	(7)
CHANGE IN CASH AND CASH EQUIVALENTS	(1)	(2)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4	7
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 3	$ 5

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Net income	$ 19	$ 24	$ 40	$ 56
Gain on derivative instruments and hedging activities – net of tax expense of $3 million, $3 million, $1 million and $3 million, respectively (Note 3)	5	5	2	5
Other comprehensive income, net of tax	5	5	2	5
Comprehensive income	$ 24	$ 29	$ 42	$ 61

The accompanying notes are an integral part of these financial statements.

Note 1 - General

The unaudited financial statements include the accounts of the Company. LG&E's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings, comprehensive income and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted, although the Company believes that the disclosures are adequate to make the information presented not misleading. These unaudited financial statements and notes should be read in conjunction with the Company's annual report for the year ended December 31, 2007, including management's discussion and analysis and the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No.

159 was adopted effective January 1, 2008 and had no impact on the statements of operations, financial position and cash flows.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives, AROs and pension assets, as required, are now provided.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to LG&E's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

Louisville Gas and Electric Company
(unaudited)

(in millions)	June 30, 2008	December 31, 2007
ARO	$ 25	$ 24
Unamortized loss on bonds	21	19
GSC adjustments	36	20
MISO exit	12	13
FAC	6	9
ECR	4	4
Other	5	5
Subtotal	109	94
Pension and postretirement benefits	109	110
Total regulatory assets	$ 218	$ 204
Accumulated cost of removal of utility plant	$ 246	$ 241
Deferred income taxes – net	47	50
Gas supply adjustments ($3 million and $10 million at June 30, 2008 and December 31, 2007, respectively) and other	18	19
Total regulatory liabilities	$ 311	$ 310

LG&E does not currently earn a rate of return on the GSC adjustments, FAC and gas performance-based ratemaking regulatory assets (included in "Other" above), all of which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. The Company will seek recovery of this asset in future proceedings with the Kentucky Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. LG&E will seek recovery of this asset in future proceedings with the Kentucky Commission. LG&E currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit, gas performance-based ratemaking and Mill Creek Ash Pond costs. Other regulatory liabilities include DSM and MISO costs included in base rates that will be netted against costs of withdrawing from the MISO in the next base rate case.

MISO Exit. LG&E and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, LG&E paid approximately $13 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. LG&E and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided LG&E with an immediate recovery of less than $1 million and will provide an estimated $2 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in LG&E's next base rate case, however, the Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In January 2008, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in May 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

ECR. In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of LG&E's environmental surcharge. An order is anticipated by the end of the year.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of LG&E's environmental surcharge. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

<u>Other Regulatory Matters</u>

Base Rate Case. In July 2008, LG&E filed an application with the Kentucky Commission for increases in gas and electric base rates. See Note 10, Subsequent Events.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by LG&E and KU, together with the

Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, LG&E, KU and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. LG&E, KU and the Kentucky Commission filed for reconsideration of the appellate court's ruling, but those requests were denied in April 2008. LG&E and KU filed a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal, which motion has been opposed by the counter-parties.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. All rights of way for one transmission line have been acquired. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line, a Meade County, Kentucky circuit court judge issued a ruling upholding the objections of two co-owners of the property crossed by the easement and dismissed that eminent domain proceeding pending the completion of the CCN appeal described above. LG&E and KU have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the eminent domain litigation. Additional condemnation proceedings involving other parcels of property to support this transmission line are also pending in neighboring Hardin County where three landowners have challenged LG&E's and KU's right to easements, on the same grounds cited by the Meade County court and other purported basis. In May and June 2008, the Hardin County Circuit Court issued rulings denying the dismissal motions, finding that LG&E and KU had established their condemnation rights and granting judgment in favor of LG&E and KU. During July 2008, the landowners filed subsequent motions in Hardin Circuit Court seeking to further challenge LG&E's and KU's condemnation right by asserting deficiencies in the air permit relating to the proposed TC2 generation unit. LG&E and KU continue to engage in settlement negotiations with the property owners. In a separate, further proceeding, certain landowners have filed a lawsuit in federal court against the U.S. Army, LG&E and KU, alleging that the U.S. Army failed to comply with Section 106 of the National Historic Preservation Act in granting an easement across Fort Knox. LG&E and KU are working with the U.S. Army in defending against the claims.

Merger Surcredit. In December 2007, LG&E submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008, to the Kentucky Commission. In June 2008, the Kentucky Commission issued an Order approving a settlement which provides for continuation of the merger surcredit for the period July 2008 through January 2009, which surcredits will terminate in connection with any new base rates to go into effect after January 2009. See Note 10, Subsequent Events.

VDT. In accordance with the Kentucky Commission's Order dated March 24, 2006, the VDT will terminate in the first billing month after the filing for a change in base rates. As a result of LG&E's filing of its application with the Kentucky Commission for an increase in gas and electric base rates in July 2008, the VDT terminated with the first billing cycle in August 2008, subject to a final balancing adjustment in September 2008.

DSM. In July 2007, LG&E and KU filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. LG&E and KU filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the Electric Reliability Organization, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. LG&E is a member of the SERC, which acts as LG&E's RRO. The SERC has assessed LG&E's compliance with certain existing mitigation plans relating to two standards resulting from a prior RRO's audit of various reliability standards, and the parties agreed in principle to a penalty of less than $1 million in June 2008. While LG&E believes itself to be in substantial compliance with the mandatory reliability standards, LG&E cannot predict the outcome of other analyses, including on-going SERC reviews relating to six additional standards, which may be conducted regarding compliance with particular reliability standards.

Depreciation Study. In December 2007, LG&E filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission, the timing of which cannot currently be determined. A revised procedural schedule was issued in June 2008, but a hearing is not currently scheduled. In July 2008, LG&E filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. The Kentucky Commission has not yet ruled on the request.

Brownfield Development Rider Tariff. In March 2008, LG&E and KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by LG&E, for implementation within approximately eight months, for its large commercial and industrial customers.

Collection Cycle Revision. In September 2007, LG&E filed an application with the Kentucky Commission to revise the collection cycle for customer bill payments from 15 days to 10 days to more closely align with the KU billing cycle and to avoid confusion for delinquent customers. In December 2007, the Kentucky Commission denied LG&E's request to shorten the collection cycle. LG&E filed a motion with the Kentucky Commission for reconsideration and received an Order granting approval. The Kentucky Commission issued additional data requests to LG&E in February 2008, and in April 2008, issued an Order denying LG&E's request to revise its collection cycle without prejudice for refiling the request in a base rate proceeding. In addition, as part of the base rate case filed on July 29, 2008, the Company has included revisions to its Terms and Conditions Tariffs. LG&E has again proposed to change the due date for customer bill payments from 15 days to 10 days. If approved, this proposal would synchronize the Collection Cycles for both utilities. See Note 10, Subsequent Events.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case are to present the proposed interconnection guidelines to the Kentucky Commission in September 2008.

Note 3 - Financial Instruments

Interest Rate Swaps (hedging derivatives). LG&E uses over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. The fair values of the swaps reflect price quotes from dealers. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature. LG&E was party to various interest rate swap agreements with aggregate notional amounts of $211 million as of June 30, 2008 and December 31, 2007. Under these swap agreements, LG&E paid fixed rates averaging 4.38% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 1.62% at June 30, 2008. The interest rate swaps are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended. The swap agreements have been designated as cash flow hedges and mature on dates ranging from 2020 to 2033. The cash flow designation was assigned because the underlying variable rate debt has variable future cash flows. Financial instruments designated as highly effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity.

Through June, LG&E recorded a pre-tax loss of $1 million in other comprehensive income during 2008, to reflect the ineffective portion of the interest rate swaps deemed highly effective. The interest rate swap that hedges against LG&E's $83 million Trimble County 2000 Series A bond has been determined to be highly effective. In June, the interest rate swaps designated to hedge against LG&E's $128 million Jefferson County 2003 Series A bond were no longer highly effective, as a result of failed auctions on the bonds. See Note 6, Short-Term and Long-Term Debt. In June 2008, LG&E recorded a $1 million mark-to-market loss in earnings on the interest rate swaps deemed ineffective related to the Jefferson County 2003 Series A bond. Amounts recorded in accumulated other comprehensive income will be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million. A deposit in the amount of $12 million, used as collateral for one of the interest rate swaps, is classified as restricted cash on the balance sheet. The amount of the deposit required is tied to the market value of the swap.

Energy Trading and Risk Management Activities (non-hedging derivatives). LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at June 30, 2007, had a maturity of less than one year. There were no contracts outstanding at June 30, 2008. Energy trading and risk management contracts are valued using

Level 2, prices actively quoted for proposed or executed transactions or quoted by brokers or observable inputs other than quoted prices.

Effective January 1, 2008, LG&E adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157. The following table sets forth by level within the fair value hierarchy LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. There are no Level 1 or Level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 2
Liabilities:	
Interest rate swaps	$ 22
Energy marketing contracts	-
Total	$ 22

Note 4 - Pension and Other Postretirement Benefit Plans

The following table provides the components of net periodic benefit cost for pension and other benefit plans:

	Three Months Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007	2008	2007	2008	2007
(in millions)								
Service cost	$ 1	$ 2	$ -	$ 1	$ 2	$ 3	$ -	$ 1
Interest cost	7	5	1	1	13	13	3	2
Expected return on plan assets	(8)	(7)	-	-	(16)	(18)	-	-
Amortization of prior service costs	1	1	-	-	3	3	1	1
Amortization of actuarial loss	-	-	1	-	-	1	-	-
Benefit cost	$ 1	$ 1	$ 2	$ 2	$ 2	$ 2	$ 4	$ 4

Net periodic benefit costs incurred by employees of LG&E are reflected in both utility plant on the balance sheets and in operating expense on the income statements. The above costs do not include allocations of net periodic benefit costs from affiliates whose employees provide services to LG&E.

The pension plans are funded in accordance with all applicable requirements of the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. In March 2008, LG&E made contributions to other postretirement benefit plans of approximately $2 million. LG&E anticipates making further voluntary contributions in 2008 to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the postretirement medical account under the pension plan up to the maximum amount allowed by law. See Note 10, Subsequent Events.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including LG&E, calculates its separate income tax for each tax period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. LG&E also files income tax returns in various state jurisdictions. With few exceptions, LG&E is no longer subject to U.S. federal income tax examinations for years before 2004. Statutes of limitations related to 2004 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed.

LG&E adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, LG&E had $1 million of unrecognized tax benefits related to federal and state income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Possible amounts of uncertain tax positions for LG&E that may decrease within the next 12 months total less than $1 million, and are based on the expiration of statutes during 2008.

The amount LG&E recognized as interest accrued related to unrecognized tax benefits in interest expense was less than $1 million at June 30, 2008 and December 31, 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, LG&E accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by LG&E upon adoption of FIN 48, or through June 30, 2008.

In June 2006, LG&E and KU filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that LG&E and KU were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credit. LG&E's portion of the TC2 tax credit will be approximately $25 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, LG&E recorded investment tax credits of $2 million and $3 million during the three months ended June 30, 2008 and 2007, respectively, and $4 million and $5 million during the six months ended June 30, 2008 and 2007, respectively, decreasing current federal income taxes.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. LG&E is monitoring, but is not currently a party to, this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 - Short-Term and Long-Term Debt

LG&E's long-term debt includes $251 million classified as current liabilities ($131 million of which are currently being held by the Company as discussed below) because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Jefferson County Series 2001 A and B and Trimble County Series 2001 A and B. Maturity dates for these bonds range from 2026 to 2027. The repurchased bonds include the Louisville Metro 2005 Series A and 2007 Series A and B bonds and the Jefferson County 2000 Series A bonds. LG&E does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the six months ended June 30, 2008, was 2.73%.

LG&E maintains bilateral lines of credit totaling $125 million which mature in June 2012. As of June 30, 2008, there was no balance outstanding under any of these facilities.

Pollution control series bonds are obligations of LG&E issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during April 2007, the county's debt was also secured by an equal amount of LG&E's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless LG&E defaults on the loan agreement.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At June 30, 2008, LG&E had an aggregate $574 million of outstanding pollution control indebtedness, of which $263 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" where there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the six months ended June 30, 2008 and 2007, the average rate on the auction rate bonds was 4.81% and 3.30%, respectively. The instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first six months of 2008, the ratings of the Louisville Metro 2003 Series A bonds were downgraded from Aaa to A2 by Moody's and from AAA to A-, and subsequently to BBB+, by S&P due to downgrades of the bond insurer. The ratings of the following bonds were downgraded from Aaa to Aa3 by Moody's and from AAA to AA by S&P due to downgrades of the bond insurer: Trimble County 2000 Series A, Jefferson County 2000 Series A, Jefferson County 2001 Series A, Trimble County 2002 Series A, Louisville Metro 2005 Series A, Louisville Metro 2007 Series A and B and Trimble County 2007 Series A.

In February 2008, LG&E issued a notice to bondholders of its intention to convert the Louisville Metro 2005 Series A and 2007 Series A and B bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. These conversions were completed in March 2008, for the 2005 Series, and in April 2008, for the two 2007 Series. In connection with the conversions, LG&E purchased the bonds from the remarketing agent.

In March 2008, LG&E issued notices to bondholders of its intention to convert the Jefferson County 2000 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in May 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

In June 2008, LG&E issued notices to bondholders of its intention to convert the Louisville Metro 2003 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent. See Note 10, Subsequent Events.

As of June 30, 2008, LG&E had repurchased bonds in the amount of $131 million. LG&E will hold some or all of such repurchased bonds until a later date, at which time LG&E may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps LG&E has taken or may take to mitigate such uncertainty, such as additional conversions, subsequent restructurings or redemption and refinancing, could result in LG&E incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
June 30, 2008	$400	$188	$212	2.43%
December 31, 2007	$400	$ 78	$322	4.75%

E.ON U.S. maintains a revolving credit facility totaling $311 million at June 30, 2008 and $150 million at December 31, 2007, to ensure funding availability for the money pool. The revolving facility as of June 30, 2008, is split into two separate loans totaling $311 million. One facility, totaling $150 million, is with E.ON North America, Inc., while the second, totaling $161 million, is with Fidelia; both are affiliated companies. The facility as of December 31, 2007, is with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
June 30, 2008	$311	$220	$91	3.17%
December 31, 2007	$150	$ 62	$88	4.97%

There were no redemptions or issuances of long-term debt year-to-date through June 30, 2008.

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in LG&E's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of LG&E contained therein). See the above-referenced notes in LG&E's Annual Report regarding such commitments or contingencies.

Construction Program. LG&E had approximately $70 million of commitments in connection with its construction program at June 30, 2008.

In June 2006, LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division for Air

Quality in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, LG&E administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the Kentucky Division for Air Quality issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. LG&E's operations are subject to a number of environmental laws and regulations, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to LG&E's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling vacating the CAIR, which decision may be subject to rehearing or other subsequent proceedings. LG&E, KU and industry parties are monitoring these further proceedings. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. LG&E is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the current invalidation of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and LG&E's and KU's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The parties are currently evaluating the possibility of seeking review in the U.S. Supreme Court. Depending on the final outcome of the pending appeal, the CAMR could be superceded by new mercury reduction rules with different or more stringent requirements. Kentucky has subsequently proposed to repeal the corresponding state mercury regulations. In addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPS incorporate certain CAIR requirements, the final outcome of the challenge to CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 through 2007 time period at a cost of $197 million. In 2001, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E under its periodic environmental surcharge mechanisms. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling $130 million during the 2008 through 2010 time period for pollution control equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by LG&E for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. LG&E is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of LG&E, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. The

Companies have complied with the information requests and are not able to predict further proceedings in this matter at this time.

General Environmental Proceedings. From time to time, LG&E appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation obligations for former manufactured gas plant sites; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; ongoing claims regarding alleged particulate emissions from LG&E's Cane Run station and ongoing claims regarding GHG emissions from LG&E's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of LG&E.

Note 8 - Segments of Business

LG&E's revenues, net income and total assets by business segment follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2008	2007	2008	2007
LG&E Electric				
Revenues	$ 240	$ 226	$ 464	$ 449
Net income	21	26	33	47
Total assets	2,632	2,558	2,632	2,558
LG&E Gas				
Revenues	58	51	248	203
Net income	(2)	(2)	7	9
Total assets	665	597	665	597
Total				
Revenues	298	277	712	652
Net income	19	24	40	56
Total assets	3,297	3,155	3,297	3,155

Note 9 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as electric operating revenues and purchased power operating expense. LG&E intercompany electric revenues and purchased power expense were as follows:

(in millions)	Three Months Ended June 30, 2008	2007	Six Months Ended June 30, 2008	2007
Electric operating revenues from KU	$25	$23	$51	$53
Purchased power from KU	14	8	29	26

Interest Charges

See Note 6, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

LG&E's intercompany interest expense was as follows:

(in millions)	Three Months Ended June 30, 2008	2007	Six Months Ended June 30, 2008	2007
Interest on money pool loans	$ 1	$ 1	$ 2	$ 1
Interest on Fidelia loans	6	5	10	7

Other Intercompany Billings

E.ON U.S. Services provides LG&E with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services is directly charged to LG&E, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of LG&E, primarily tax settlements, and other payments made by LG&E on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from LG&E were as follows:

(in millions)	Three Months Ended June 30, 2008	2007	Six Months Ended June 30, 2008	2007
E.ON U.S. Services billings to LG&E	$60	$154	$102	$277
LG&E billings to KU	4	23	5	33
KU billings to LG&E	14	8	37	22
LG&E billings to E.ON U.S. Services	1	28	3	29

In June 2008, LG&E transferred assets related to Trimble County Unit 2 with a net book value of $10 million to KU.

In March 2008, LG&E paid a dividend of $40 million to its common shareholder, E.ON U.S.

Note 10 - Subsequent Events

On July 3, 2008, LG&E made contributions to other postretirement benefit plans of approximately $2 million.

On July 9, 2008, the Louisville Metro 2003 Series A bonds were converted from an auction rate mode to a weekly interest rate mode. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

On July 25, 2008, LG&E borrowed $25 million from Fidelia for a period of 10 years at a fixed rate of 6.21%. The loan is unsecured.

On July 29, 2008, LG&E filed an application with the Kentucky Commission for increases in gas base rates of approximately 4.5% or $30 million annually and in electric base rates of approximately 2.0% or $15 million annually. LG&E has requested the increases based on the twelve month test year ended April 30, 2008. LG&E requested new base rates to become effective on and after September 1, 2008. In conjunction with the filing of the application for changes in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. Under Kentucky Commission practice, new rates will most likely be suspended an additional five months with an effective date on and after February 1, 2009, subject to refund if an order is not issued by such time. The rate review proceeding, which will likely involve opposition filings by intervenors or other third-parties, should be completed in early 2009, subject to a number of factors.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during the three and six month periods ended June 30, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of December 31, 2007, LG&E provided natural gas to approximately 326,000 customers and electricity to approximately 401,000 customers in Louisville and adjacent areas in Kentucky. LG&E's electric service area covers approximately 700 square miles in 9 counties. LG&E provides natural gas service in its electric service area and 8 additional counties in Kentucky. LG&E's coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions, produce most of LG&E's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

LG&E is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making LG&E an indirect wholly-owned subsidiary of E.ON. LG&E's affiliate, KU, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

In July 2008, LG&E filed an application with the Kentucky Commission for increases in base gas rates of approximately 4.5% or $30 million annually and in base electric rates of approximately 2.0% or $15 million annually. In conjunction with the filing of the application for changes in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT and merger surcredit will result in a $21 million increase in revenues annually. These proceedings should be completed by early 2009.

Environmental Matters

Protection of the environment is a major priority for LG&E. Federal, state and local regulatory agencies have issued LG&E permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric and gas utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Three Months Ended June 30, 2008, Compared to Three Months Ended June 30, 2007

Net Income

Net income for the three months ended June 30, 2008, decreased $5 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($26 million) and increased other expense ($3 million), partially offset by increased revenues ($21 million), lower income taxes ($2 million) attributable to lower pre-tax income and lower interest expense ($1 million).

Revenues

Electric revenues increased $14 million in the three months ended June 30, 2008, primarily due to:

- Increased wholesale sales ($18 million) due to increased volumes and increased wholesale market pricing
- Increased fuel costs ($3 million) billed to customers through the FAC due to increased fuel prices
- Increased demand side management cost recovery ($2 million) due to additional conservation programs
- Increased ECR surcharge ($2 million) due to increased recoverable capital spending
- Decreased sales volumes to native load ($11 million) due in part to a 19% decrease in cooling degree days

Natural gas revenues increased $7 million in the three months ended June 30, 2008, primarily due to:

- Increased average cost of gas billed to retail customers ($9 million) due to increased gas costs
- Decreased sales volumes ($2 million) due to a 15% decrease in heating degree days

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expense. Increases or decreases in the costs of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission.

Fuel for electric generation increased $1 million in the three months ended June 30, 2008, primarily due to increased transportation costs.

Power purchased expense increased $6 million in the three months ended June 30, 2008, primarily due to:

- Increased volumes purchased ($7 million) due to increased intercompany purchases
- Decreased native load and industrial sales ($1 million) due to lower industrial production in the Company's service territory

Gas supply expenses increased $7 million in the three months ended June 30, 2008, primarily due to:

- Increased costs of net gas supply ($12 million) primarily due to increased unit costs
- Decreased volumes of natural gas delivered to the distribution system ($5 million) due to decreased demand

Revenues

Electric revenues in the six months ended June 30, 2008, increased $15 million primarily due to:

- Increased wholesales sales ($12 million) due to increased wholesale market pricing
- Increased fuel costs ($7 million) billed to customers through the FAC due to increased fuel prices
- Increased ECR surcharge ($4 million) due to increased recoverable capital spending
- Increased demand side management cost recovery ($2 million) due to additional conservation programs
- Decreased sales volumes delivered ($10 million) resulting in part from a 25% decrease in cooling days

Natural gas revenues in the six months ended June 30, 2008, increased $45 million primarily due to:

- Increased average cost of gas ($36 million) billed to retail customers due to increased gas costs
- Increased sales volumes delivered ($11 million) due to a 5% increase in heating degree days
- Decreased wholesale sales ($2 million) due to decreased volumes

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expense. Increases or decreases in the cost of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission.

Fuel for electric generation increased $4 million in the six months ended June 30, 2008, primarily due to:

- Increased contract and spot market pricing for coal and natural gas ($11 million) due to increased coal transportation costs
- Decreased generation ($7 million) due to decreased native load sales

Power purchased expense increased $4 million in the six months ended June 30, 2008, primarily due to:

- Increased volumes purchased ($2 million) due to increased intercompany purchases as a result of lower KU native load due to milder weather and lower industrial sales
- Increased fuel costs ($1 million) associated with these intercompany purchases
- Increased prices for purchases used to serve retail customers ($1 million)

Gas supply expense increased $45 million in the six months ended June 30, 2008, primarily due to:

- Increased cost of net gas supply ($41 million) primarily due to increased unit cost
- Increased volumes of natural gas delivered to the distribution system ($4 million) due to increased demand

Other operation and maintenance expense increased $24 million in the six months ended June 30, 2008, primarily due to increased maintenance expense ($12 million) and increased other operation expense ($12 million).

Maintenance expense increased $12 million in the six months ended June 30, 2008, primarily due to:

- Increased boiler and electric plant maintenance expense ($7 million) due to higher cost for outside contractors and materials
- Increased maintenance of overhead lines ($3 million) due to an increase in storm restoration work for 2008
- Increased maintenance supervisor and engineering expense ($1 million) due to engineering consulting and testing costs for new projects in 2008
- Increased gas mains maintenance expense ($1 million)

Other operation expense increased $12 million in the six months ended June 30, 2008, primarily due to:

- Increased steam expense ($7 million) due to a non-recurring capital lease adjustment in 2007
- Increased demand side management conservation expense ($3 million) due to additional conservation programs
- Increased generation expense ($1 million) due to outages
- Increased distribution expense ($1 million) due to increased gas leak repairs and regulatory inspections

Interest expense, including interest expense to affiliated companies, increased $4 million in the six months ended June 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.9	3.3
Reserve release	-	(0.1)
Amortization of investment tax credits	(3.3)	(2.4)
Other differences	(1.3)	(2.5)
Effective income tax rate	33.3%	33.3%

The effective income tax rate for the six months ended June 30, 2008, compared to the six months ended June 30, 2007, remained the same. State income taxes net of federal benefit decreased due to an increase in state coal credits. Amortization of investment tax credits increased due to the changes in levels of pretax income. These items were offset by various other differences.

Liquidity and Capital Resources

LG&E uses net cash generated from its operations and external financing (including financing from affiliates) to fund construction of plant and equipment and the payment of dividends. LG&E believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was $168 million and $92 million for the six months ended June 30, 2008 and 2007, respectively.

The 2008 increase of $76 million was primarily the result of increases in cash due to changes in:

- Pension funding ($56 million) due to higher pension funding in 2007
- Other current liabilities ($17 million)
- Accounts receivable ($11 million)
- Other ($11 million)
- Gas supply clause receivable ($4 million)

These increases were partially offset by cash used by changes in:

- Accounts payable ($11 million)
- Earnings, net of non-cash items ($11 million)
- Materials and supplies ($1 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $118 million and $87 million in the six months ended June 30, 2008 and 2007, respectively. Net cash used for investing activities increased $20 million in the six months ended June 30, 2008 compared to 2007, due to increased capital expenditures of $31 million, partially offset by an asset transferred to an affiliate of $10 million and cash provided by changes in long-term derivative liability (non-hedging) of $1 million.

Financing Activities

Net cash outflows from financing activities were $62 million and $7 million in the six months ended June 30, 2008 and 2007, respectively. Net cash used in financing activities increased $55 million in the six months ended June 30, 2008 compared to 2007, due to lower long-term borrowings from affiliated company of $138 million and the reacquisition of bonds in the amount of $131 million, partially offset by increased short-term borrowings from affiliated company of $91 million, the retirement of preferred stock of $91 million in 2007, decreased dividend payments of $29 million, and decreased change in the mark-to-market of long-term derivative liability (cash flow hedge) of $3 million.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

LG&E expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $735 million, consisting primarily of construction of TC2 totaling approximately $85 million (including $25 million for environmental controls), gas main replacement initiatives of approximately $50 million, redevelopment of the Ohio Falls hydroelectric facility totaling approximately $45 million, a customer care system totaling approximately $30 million and on-going construction related to generation and distribution assets.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

LG&E has a variety of funding alternatives available to meet its capital requirements. LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds of up to $400 million available to LG&E at market-based rates. Fidelia also provides long-term intercompany funding to LG&E. See Note 6 of Notes to Financial Statements.

LG&E's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See Note 7 of Notes to Financial Statements for current commitments. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In November 2007, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds.

LG&E's debt ratings as of June 30, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework . The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company's internal control over financial reporting that occurred during the six months ended June 30, 2008, that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting.

LG&E is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Legal Proceedings

For a description of the significant legal proceedings involving LG&E, reference is made to the information under the following captions of LG&E's Annual Report for the year ended December 31, 2007: Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in LG&E's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, LG&E believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on LG&E's financial position or results of operations.

FINANCIAL STATEMENTS

SEPTEMBER 30, 2008

Louisville Gas and Electric Company

Financial Statements and Additional Information

As of September 30, 2008 and December 31, 2007
and for the three-month and nine-month periods ended
September 30, 2008 and 2007

INDEX OF ABBREVIATIONS

ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	Louisville Gas and Electric Company
DSM	Demand Side Management
ECR	Environmental Cost Recovery
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EUSIC	E.ON US Investments Corp.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation Number
GHG	Greenhouse Gas
GSC	Gas Supply Clause
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offer Rate
Mcf	Thousand cubic feet
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Units
Moody's	Moody's Investor Services, Inc.
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
S&P	Standard & Poor's Rating Service
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process

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Financial Statements (Unaudited)

Louisville Gas and Electric Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
OPERATING REVENUES:				
Electric	$ 283	$ 270	$ 747	$ 718
Gas	47	36	295	240
Total operating revenues	330	306	1,042	958
OPERATING EXPENSES:				
Fuel for electric generation	94	89	253	245
Power purchased	27	17	73	60
Gas supply expenses	34	23	228	171
Other operation and maintenance expenses	90	67	249	201
Depreciation and amortization	32	31	95	94
Total operating expenses	277	227	898	771
OPERATING INCOME	53	79	144	187
Other expense (income) – net	(5)	(1)	(1)	-
Interest expense (Notes 3, 5 and 6)	4	7	19	22
Interest expense to affiliated companies (Note 9)	8	6	20	15
INCOME BEFORE INCOME TAXES	46	67	106	150
Federal and state income taxes (Note 5)	13	22	33	49
NET INCOME	$ 33	$ 45	$ 73	$ 101

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Balance at beginning of period	$ 690	$ 625	$ 690	$ 639
Net income	33	45	73	101
Preferred stock buyback	-	-	-	(4)
Subtotal	723	670	763	736
Cash dividends declared on stock:				
Cumulative preferred	-	-	-	1
Common	-	-	40	65
Subtotal	-	-	40	66
Balance at end of period	$ 723	$ 670	$ 723	$ 670

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	September 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 4	$ 4
Restricted cash	9	7
Accounts receivable – less reserves of $2 million as of September 30, 2008 and December 31, 2007	165	189
Materials and supplies:		
Fuel (predominantly coal)	35	46
Gas stored underground	127	81
Other materials and supplies	32	31
Prepayments and other current assets	5	13
Total current assets	377	371
Utility plant:		
At original cost	4,465	4,319
Less: reserve for depreciation	1,691	1,619
Net utility plant	2,774	2,700
Deferred debits and other assets:		
Restricted cash	13	12
Prepaid pension assets	15	14
Regulatory assets (Note 2):		
Pension and postretirement benefits	109	110
Other	117	94
Other assets	6	12
Total deferred debits and other assets	260	242
Total assets	$ 3,411	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	September 30, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 120	$ 120
Notes payable to affiliated companies (Notes 6 and 9)	345	78
Accounts payable	109	111
Accounts payable to affiliated companies (Note 9)	38	57
Customer deposits	21	19
Property taxes	13	10
Other current liabilities	29	24
Total current liabilities	675	419
Long-term debt:		
Long-term debt (Note 6)	195	454
Long-term debt to affiliated company (Notes 6 and 9)	435	410
Total long-term debt	630	864
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	360	342
Accumulated provision for pensions and related benefits (Note 4)	100	94
Investment tax credit (Note 5)	49	46
Asset retirement obligation	31	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	248	241
Deferred income taxes – net	47	50
Gas supply adjustment and other	28	19
Long-term derivative liability	24	22
Other liabilities	23	25
Total deferred credits and other liabilities	910	869
Common equity:		
Common stock, without par value –		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	60	60
Accumulated other comprehensive loss	(11)	(13)
Retained earnings	723	690
Total common equity	1,196	1,161
Total liabilities and equity	$ 3,411	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30,	
	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 73	$ 101
Items not requiring cash currently:		
Depreciation and amortization	95	94
Deferred income taxes – net	11	4
Investment tax credit – net	3	6
Gain from disposal of assets	(9)	-
Other	13	(1)
Changes in current assets and liabilities:		
Accounts receivable	24	30
Material and supplies	(36)	(6)
Accounts payable	(8)	(27)
Other current liabilities	6	(2)
Pension funding	(5)	(56)
Fuel adjustment clause receivable, net	2	(10)
Gas supply clause receivable, net	(13)	(21)
Other	13	16
Net cash provided by operating activities	169	128
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(179)	(137)
Asset transferred to affiliate (Note 9)	10	-
Proceeds from sale of asset	9	-
Long-term derivative liability (non-hedging) (Note 3)	5	-
Net cash used for investing activities	(155)	(137)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings from affiliated company (Note 6)	25	138
Short-term borrowings from affiliated company - net (Note 6)	266	38
Reacquired bonds	(259)	-
Retirement of first mortgage bonds	-	(126)
Issuance of pollution control bonds	-	126
Retirement of preferred stock	-	(92)
Payment of dividends	(40)	(69)
Change in restricted cash	(1)	(9)
Long-term derivative liability (hedging) (Note 3)	(5)	(1)
Net cash provided by (used for) financing activities	(14)	5
CHANGE IN CASH AND CASH EQUIVALENTS	-	(4)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4	7
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 4	$ 3

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Net income	$ 33	$ 45	$ 73	$ 101
Gain/(loss) on derivative instruments and hedging activities – net of tax expense/(benefit) of less than $1 million and $(3) million in the three months ended September 30, 2008 and 2007, respectively, and $1 million in the nine months ended September 30, 2008 and 2007, (Note 3)	-	(4)	2	1
Comprehensive income	$ 33	$ 41	$ 75	$ 102

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Notes to Financial Statements
(Unaudited)

Note 1 - General

The unaudited financial statements include the accounts of the Company. LG&E's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings, comprehensive income and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted. These unaudited financial statements and notes should be read in conjunction with the Company's financial statements and additional information for the year ended December 31, 2007, including the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 was adopted effective January 1, 2008 and the Company elected not to fair value its eligible financial assets and liabilities.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments related to SFAS No. 157 have been evaluated and have no impact on the Company's financial statements. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives and AROs, as required, are now provided.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to LG&E's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

Louisville Gas and Electric Company
(unaudited)

(in millions)	September 30, 2008	December 31, 2007
ARO	$ 29	$ 24
Unamortized loss on bonds	24	19
GSC adjustments	35	20
MISO exit	12	13
FAC	8	9
ECR	4	4
Other	5	5
Subtotal	117	94
Pension and postretirement benefits	109	110
Total regulatory assets	$ 226	$ 204
Accumulated cost of removal of utility plant	$ 248	$ 241
Deferred income taxes – net	47	50
Gas supply adjustments ($12 million and $10 million at September 30, 2008 and December 31, 2007, respectively) and other	28	19
Total regulatory liabilities	$ 323	$ 310

LG&E does not currently earn a rate of return on the GSC adjustments, FAC and gas performance-based ratemaking regulatory assets (included in "Other" above), all of which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. LG&E is seeking recovery of this asset with the Kentucky Commission as part of the current base rate case. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. LG&E is seeking recovery of this asset with the Kentucky Commission as part of the current base rate case. LG&E currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit and Mill Creek Ash Pond costs. Other regulatory liabilities include DSM and MISO costs currently included in base rates that will be netted against costs of withdrawing from the MISO in the next base rate case.

MISO Exit. LG&E and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, LG&E paid $13 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. LG&E and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided LG&E with an immediate recovery of less than $1 million and will provide an estimated $2 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in LG&E's base rate case, for which a hearing is scheduled beginning on January 13, 2009. The Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In August 2008, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period November 1, 2007 through April 30, 2008. A hearing was held on October 7, 2008. A second hearing has been scheduled for November 25, 2008, for the sole purpose of hearing public comments, if any, from several counties in which the newspapers failed to publish notice as requested in a timely manner. An order is expected in December of 2008 or first quarter of 2009.

In January 2008, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in May 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

ECR. In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of LG&E's environmental surcharge. The Kentucky Commission issued an Order in August 2008, approving the charges and credits billed through the ECR during the review period and the rate of return on capital.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of LG&E's environmental surcharge. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Other Regulatory Matters

Hurricane Ike Wind Storm. In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through LG&E's service territory causing significant outages and system damage. In October 2008, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $24 million of expenses related to the storm restoration. An order has been requested by the end of the year.

Base Rate Case. In July 2008, LG&E filed an application with the Kentucky Commission requesting increases in base gas rates of 4.5% or $30 million annually and in base electric rates of 2.0% or $15 million annually. A hearing is scheduled beginning on January 13, 2009. The requested rates have been suspended until February 5, 2009, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. In conjunction with the filing of the application for changes in base rates, based on previous orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT surcredit and merger surcredit will result in a $21 million increase in revenues annually.

CMRG and KCCS Contributions. In July 2008, LG&E and KU, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. LG&E and KU jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and rate recovery will be considered in each company's next base rate case.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by LG&E and KU, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, LG&E, KU and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. LG&E and KU filed a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal, which motion has been opposed by the counter-parties.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. All rights of way for one transmission line have been acquired. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line, a Meade County, Kentucky court issued a ruling upholding the objections of two property co-owners and dismissed the condemnation proceeding pending the completion of the CCN appeal described above. LG&E and KU have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the condemnation litigation. Additional condemnation proceedings involving other parcels of property to support this transmission line are also pending in neighboring Hardin County where three landowners have challenged LG&E's and KU's right to easements, on the same grounds cited by the Meade County court and other purported bases, including asserted deficiencies in the air permit relating to the TC2 generation unit. In May, July and August 2008, the Hardin County Circuit Court issued rulings denying the property owners' various motions, finding that LG&E and KU had established their condemnation rights and granting judgment in favor of LG&E and KU. In August 2008, the property owners petitioned for intermediate relief to the Kentucky Court of Appeals and received a stay preventing LG&E and KU access to the properties. LG&E and KU have made responsive pleadings at the Court of Appeals and continue to engage in settlement negotiations with the property owners. In a separate, further proceeding, certain landowners have filed a lawsuit in federal court in Louisville, Kentucky against the U.S. Army, LG&E and KU, alleging that the U.S. Army failed to comply with Section 106 of the National Historic Preservation Act in granting an easement across Fort Knox. LG&E and KU are working with the U.S. Army in defending against the claims. LG&E and KU are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to these real property proceedings.

Merger Surcredit. In December 2007, LG&E submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008, to the Kentucky Commission. In June 2008, the Kentucky Commission issued an Order approving a settlement which provides for continuation of the merger surcredit until new base rates go into effect.

VDT. In accordance with the Kentucky Commission's Order dated March 24, 2006, the VDT surcredit terminated in the first billing month after the filing for a change in base rates. As LG&E filed its application with the Kentucky Commission for an increase in gas and electric base rates in July 2008, the VDT surcredit terminated with the first billing cycle in August 2008, subject to a final balancing adjustment of less than $1 million made in September 2008.

DSM. In July 2007, LG&E and KU filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. LG&E and KU filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. LG&E is a member of the SERC, which acts as LG&E's RRO. During May 2008, the SERC and LG&E agreed in principle to a settlement involving penalties totaling less than $1 million concerning LG&E's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. The SERC and LG&E are currently involved in settlement negotiations concerning a June 2008 self-report by LG&E relating to three other standards. Additionally, LG&E has submitted to the SERC an October 2008 self report of a possible violation relating to one further standard, for which SERC proceedings are in the early stages and therefore unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements in principle with the SERC proceed to the NERC and FERC review before becoming final. While LG&E believes itself to be in compliance with the mandatory reliability standards, LG&E cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Depreciation Study. In December 2007, LG&E filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission. In July 2008, LG&E filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding.

Brownfield Development Rider Tariff. In March 2008, LG&E received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by LG&E, for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008.

Collection Cycle Revision. In September 2007, LG&E filed an application with the Kentucky Commission to revise the collection cycle for customer bill payments from 15 days to 10 days to more closely align with the KU billing cycle and to avoid confusion for delinquent customers. In December 2007, the Kentucky Commission denied LG&E's request to shorten the collection cycle. LG&E filed a motion with the Kentucky Commission for reconsideration and received an Order granting approval. The Kentucky Commission issued additional data requests to LG&E in February 2008, and in April 2008, issued an Order denying LG&E's request to revise its collection cycle without prejudice for refiling the request in a base rate proceeding. As part of the base rate case filed on July 29, 2008, the Company has included revisions to its terms and conditions tariffs in which LG&E has again proposed to change the due date for customer bill payments from 15 days to 10 days. If approved, this proposal would synchronize the collection cycles for both utilities.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented the proposed interconnection guidelines to the Kentucky Commission in October 2008. An order is expected by the end of the year.

Note 3 - Financial Instruments

Interest Rate Swaps (hedging derivatives). LG&E uses over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. The fair values of the swaps reflect price quotes from dealers. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature. LG&E was party to various interest rate swap agreements with aggregate notional amounts of $211 million as of September 30, 2008 and December 31, 2007. Under these swap agreements, LG&E paid fixed rates averaging 4.38% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 4.16% at September 30, 2008. The interest rate swaps are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended. The swap agreements have been designated as cash flow hedges and mature on dates ranging from 2020 to 2033. The cash flow designation was assigned because the underlying variable rate debt has variable future cash flows. Financial instruments designated as highly effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity.

Through September 30, 2008, LG&E recorded a pre-tax loss of $1 million in other expense (income) during 2008, to reflect the ineffective portion of the interest rate swaps deemed highly effective. The interest rate swap that hedges LG&E's $83 million Trimble County 2000 Series A bond continues to be highly effective. In June 2008, the interest rate swaps designated to hedge LG&E's $128 million Jefferson County 2003 Series A bond were no longer highly effective, as a result of failed auctions on the bonds. See Note 6, Short-Term and Long-Term Debt. Through September 30, 2008, LG&E recorded a $4 million mark-to-market loss in earnings on the interest rate swaps deemed ineffective related to the Jefferson County 2003 Series A bond. Amounts recorded in accumulated other comprehensive income will be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million. A deposit in the amount of $13 million, used as collateral for one of the interest rate swaps, is classified as restricted cash on the balance sheet. The amount of the deposit required is tied to the market value of the swap.

Energy Trading and Risk Management Activities (non-hedging derivatives). LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at September 30, 2008 and 2007, had a maturity of less than one year. Energy trading and risk management contracts are valued using prices actively quoted for proposed or executed transactions or quoted by brokers or observable inputs other than quoted prices. Collateral related to the energy trading and risk management contracts is categorized as restricted cash.

Effective January 1, 2008, LG&E adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157. The following table sets forth by level within the fair value hierarchy LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2008. There are no Level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1	Level 2	Total
Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Energy trading and risk management contracts cash collateral	1	-	1
Interest rate swap cash collateral	13	-	13
Total Assets	$ 14	$ 1	$ 15
Liabilities:			
Interest rate swap	$ -	$ 24	$ 24
Total Liabilities	$ -	$ 24	$ 24

Note 4 - Pension and Other Postretirement Benefit Plans

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both LG&E employees and E.ON U.S. Services employees who are providing services to the utility. The E.ON U.S. Services costs that are allocated to LG&E are approximately 43% of E.ON U.S. Services total costs for both 2008 and 2007.

Pension Benefits

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service cost	$ 2	$ 4	$ 7	$ 11
Interest cost	14	19	40	60
Expected return on plan assets	(17)	(26)	(50)	(81)
Amortization of prior service costs	3	4	9	13
Amortization of actuarial loss	1	1	2	4
Benefit cost	$ 3	$ 2	$ 8	$ 7

Other Postretirement Benefits

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service cost	$ -	$ 1	$ 1	$ 1
Interest cost	1	3	4	4
Amortization of transition costs	-	-	1	1
Amortization of prior service costs	1	1	1	1
Benefit cost	$ 2	$ 5	$ 7	$ 7

During 2008, LG&E made contributions to other postretirement benefit plans of $4 million. LG&E anticipates making further voluntary contributions to the postretirement plan, but no additional contributions to the pension plan in 2008.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including LG&E, calculates its separate income tax for each tax period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. LG&E also files income tax returns in various state jurisdictions. With few exceptions, LG&E is no longer subject to U.S. federal income tax examinations for years before 2005. Statutes of limitations related to 2005 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process".

This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed.

LG&E adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, LG&E had $1 million of unrecognized tax benefits related to federal and state income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Possible amounts of uncertain tax positions for LG&E that may decrease within the next 12 months total less than $1 million, and are based on the expiration of the audit periods as defined in the statutes.

The amount LG&E recognized as interest accrued related to unrecognized tax benefits in interest expense was less than $1 million as of September 30, 2008 and December 31, 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, LG&E accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by LG&E upon adoption of FIN 48, or through September 30, 2008.

In June 2006, LG&E and KU filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that LG&E and KU were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credit. LG&E's portion of the TC2 tax credit will be approximately $25 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, LG&E recorded investment tax credits of $3 million during each of the three month periods ended September 30, 2008 and 2007, and $6 million and $8 million during the nine months ended September 30, 2008 and 2007, respectively, decreasing current federal income taxes.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. In August 2008, the plaintiffs submitted an amended complaint alleging additional claims for relief. LG&E is monitoring, but is not currently a party to, this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 - Short-Term and Long-Term Debt

LG&E's long-term debt includes $120 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Jefferson County Series 2001 A and B and Trimble County Series 2001 A and B. Maturity dates for these bonds range from 2026 to 2027. LG&E does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the nine months ended September 30, 2008, was 2.53%.

As of September 30, 2008, LG&E maintained bilateral lines of credit totaling $125 million which mature in June 2012. At that time, there was no balance outstanding under any of these facilities.

Pollution control series bonds are obligations of LG&E issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during April 2007, the county's debt was also secured by an equal amount of LG&E's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless LG&E defaults on the loan agreement.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At September 30, 2008, LG&E had an aggregate $574 million of outstanding pollution control indebtedness, of which $135 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" where there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the nine months ended September 30, 2008 and 2007, the average rate on the auction rate bonds was 4.58% and 3.46%, respectively. The instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first nine months of 2008, the ratings of the Louisville Metro 2003 Series A bonds were downgraded from Aaa to A2 by Moody's and from AAA to A-, and subsequently to BBB+, by S&P due to downgrades of the bond insurer. The ratings of the following bonds were downgraded from Aaa to Aa3 by Moody's and from AAA to AA by S&P due to downgrades of the bond insurer: Trimble County 2000 Series A, Jefferson County 2000 Series A, Jefferson County 2001 Series A, Trimble County 2002 Series A, Louisville Metro 2005 Series A, Louisville Metro 2007 Series A and B and Trimble County 2007 Series A.

In February 2008, LG&E issued a notice to bondholders of its intention to convert the Louisville Metro 2005 Series A and 2007 Series A and B bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. These conversions were completed in March 2008, for the 2005 Series, and in April 2008, for the two 2007 Series. In connection with the conversions, LG&E purchased the bonds from the remarketing agent.

In March 2008, LG&E issued notices to bondholders of its intention to convert the Jefferson County 2000 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in May 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

In June 2008, LG&E issued notices to bondholders of its intention to convert the Louisville Metro 2003 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

As of September 30, 2008, LG&E had repurchased bonds in the amount of $259 million. LG&E will hold some or all of such repurchased bonds until a later date, at which time LG&E may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps LG&E has taken or may take to mitigate such uncertainty, such as additional conversions, subsequent restructurings or redemption and refinancing, could result in LG&E incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2008	$400	$345	$ 55	2.45%
December 31, 2007	$400	$ 78	$322	4.75%

E.ON U.S. maintains a revolving credit facility totaling $489 million at September 30, 2008 and $150 million at December 31, 2007, to ensure funding availability for the money pool. The revolving facility as of September 30, 2008, is split into separate loans. One facility, totaling $150 million, is with E.ON North America, Inc., while the remaining loans, totaling $339 million, are with Fidelia; both are affiliated companies. The facility as of December 31, 2007, is with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2008	$489	$469	$20	3.94%
December 31, 2007	$150	$ 62	$88	4.97%

There were no redemptions of long-term debt year-to-date through September 30, 2008.

The Company issued unsecured long-term debt year-to-date through September 30, 2008, totaling $25 million. This debt, due to Fidelia, has a maturity date in 2018.

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in LG&E's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of LG&E contained therein). See the above-referenced notes in LG&E's Annual Report regarding such commitments or contingencies.

Construction Program. LG&E had approximately $57 million of commitments in connection with its construction program at September 30, 2008.

In June 2006, LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, LG&E administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ has 90 days to respond to the EPA's order. Although the Company does not expect material changes in the permit as a result of the petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. LG&E's operations are subject to a number of environmental laws and regulations, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to LG&E's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding statutory and regulatory infirmities in the CAIR and potentially vacating it, and has conducted subsequent proceedings on the matter. During October 2008, the appellate court issued a ruling requesting briefs of the parties regarding whether vacating the CAIR is the applicable relief to be granted. LG&E, KU and industry parties are monitoring these further proceedings. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. LG&E is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the current invalidation of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and LG&E's and KU's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. In addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

In February 2008, a federal appellate court issued a decision vacating the CAMR. Certain parties have filed a petition seeking review in the U.S. Supreme Court. Depending on the final outcome of the pending appeal, the CAMR could be superseded by new mercury reduction rules with different or more stringent requirements. Kentucky has subsequently proposed to repeal the corresponding state mercury regulations. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the final outcome of the challenge to CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 through 2007 time period at a cost of $197 million. In 2001, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E under its periodic environmental surcharge mechanisms. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling $100 million during the 2008 through 2010 time period for pollution control equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by LG&E for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. LG&E is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. LG&E is also monitoring relevant regulatory proceedings involving the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of LG&E, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. LG&E and KU have complied with the information requests and are not able to predict further proceedings in this matter at this time.

General Environmental Proceedings. From time to time, LG&E appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation obligations for former manufactured gas plant sites; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; ongoing claims regarding alleged particulate emissions from LG&E's Cane Run station and claims regarding GHG emissions from LG&E's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of LG&E.

Note 8 - Segments of Business

LG&E's revenues, net income and total assets by business segment follow:

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
LG&E Electric				
Revenues	$ 283	$ 270	$ 747	$ 718
Net income	37	50	70	97
Total assets	2,637	2,558	2,637	2,558
LG&E Gas				
Revenues	47	36	295	240
Net income	(4)	(5)	3	4
Total assets	774	659	774	659
Total				
Revenues	330	306	1,042	958
Net income	33	45	73	101
Total assets	3,411	3,217	3,411	3,217

Note 9 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Intercompany billings to and from LG&E were as follows:

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
E.ON U.S. Services billings to LG&E	$50	$52	$152	$302
LG&E billings to KU	-	2	5	35
KU billings to LG&E	21	11	58	33
LG&E billings to E.ON U.S. Services	1	9	4	11

In June 2008, LG&E transferred assets related to Trimble County Unit 2 with a net book value of $10 million to KU.

In March 2008, LG&E paid a dividend of $40 million to its common shareholder, E.ON U.S.

Note 10 - Subsequent Events

On October 21, 2008, the Kentucky Commission authorized the Company to issue up to $100 million of new long-term debt to its affiliate Fidelia.

On October 27, 2008, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $24 million of expenses related to the Hurricane Ike wind storm restoration. An order has been requested by the end of the year.

On October 30, 2008, the Kentucky Commission issued an Order approving the establishment of regulatory assets for the Companies' contributions to the CMRG and KCCS. Rate recovery will be considered in each company's next base rate case.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during the three and nine month periods ended September 30, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of September 30, 2008, LG&E provided natural gas to approximately 324,000 customers and electricity to approximately 402,000 customers in Louisville and adjacent areas in Kentucky. LG&E's electric service area covers approximately 700 square miles in 9 counties. LG&E provides natural gas service in its electric service area and 8 additional counties in Kentucky. LG&E's coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions, produce most of LG&E's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

LG&E is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making LG&E an indirect wholly-owned subsidiary of E.ON. LG&E's affiliate, KU, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

In July 2008, LG&E filed an application with the Kentucky Commission for increases in base gas rates of approximately 4.5% or $30 million annually and in base electric rates of approximately 2.0% or $15 million annually. In conjunction with the filing of the application for changes in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT surcredit and merger surcredit will result in a $21 million increase in revenues annually. A hearing is scheduled beginning on January 13, 2009. The requested rates have been suspended until February 5, 2009, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an Order in the proceeding.

In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through LG&E's service territory causing significant outages and system damage. In October 2008, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $24 million of expenses related to the storm restoration. An order has been requested by the end of the year.

Environmental Matters

Protection of the environment is a major priority for LG&E. Federal, state and local regulatory agencies have issued LG&E permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric and gas utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Three Months Ended September 30, 2008, Compared to
Three Months Ended September 30, 2007

Net Income

Net income for the three months ended September 30, 2008, decreased $12 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($50 million), partially offset by increased revenues ($24 million), decreased income taxes ($9 million), increased other income ($4 million) and decreased interest expense ($1 million).

Revenues

Electric revenues increased $13 million in the three months ended September 30, 2008, primarily due to:

- Increased wholesale sales ($19 million) due to increased volumes and increased wholesale market pricing
- Increased fuel costs billed to customers through the FAC ($10 million) due to increased fuel prices
- Increase demand charges ($3 million) due to higher peak load
- Decrease in the merger surcredit distribution to customers ($3 million)
- Decreased sales volumes to native load ($22 million) due in part to a 15% decrease in cooling degree days and outages related to damage from the Hurricane Ike wind storm

Natural gas revenues increased $11 million in the three months ended September 30, 2008, primarily due to:

- Increased average cost of gas billed to retail customers ($14 million) due to increased gas costs

- Decreased sales volumes ($3 million) due to a decrease in gas demand

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expense. Increases or decreases in the costs of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission.

Fuel for electric generation increased $5 million in the three months ended September 30, 2008, primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($8 million)
- Decreased generation ($3 million) due to decreased native load sales

Power purchased expense increased $10 million in the three months ended September 30, 2008, primarily due to:

- Increased volumes purchased for native load ($8 million) due to increased intercompany purchases as a result of lower KU native load due to milder weather and lower industrial sales
- Increased native load sales ($2 million) due to increased fuel prices and increased volumes due to increased unit outages

Gas supply expenses increased $11 million in the three months ended September 30, 2008, due to increased cost of net gas supply billed to customers, primarily due to increased cost per Mcf.

Other operation and maintenance expense increased $23 million in the three months ended September 30, 2008, primarily due to increased maintenance expense ($17 million) and increased other operation expense ($6 million).

Maintenance expense increased $17 million in the three months ended September 30, 2008, primarily due to increased electric maintenance due to higher costs for outside contractors and materials partially as a result of the Hurricane Ike wind storm.

Other operation expense increased $6 million in the three months ended September 30, 2008, primarily due to increased overhead lines expense due to the Hurricane Ike wind storm.

Interest expense, including interest expense to affiliated companies, decreased $1 million in the three months ended September 30, 2008, primarily due to repurchased bonds ($3 million) offset by increased borrowings ($2 million).

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	(1.6)	3.9
Reduction of income tax reserve	(0.4)	(0.9)
Amortization of investment tax credits	(2.2)	(1.5)
Other differences	(2.5)	(3.7)
Effective income tax rate	28.3%	32.8%

The effective income tax rate decreased for the three months ended September 30, 2008, compared to the three months ended September 30, 2007, due primarily to a decrease in state income taxes net of federal benefit. State income taxes were favorably impacted by $4 million of coal and recycle credits recorded during the period. Amortization of investment tax credits increased due to the changes in levels of pretax income. These items were partially offset by various other differences.

Nine Months Ended September 30, 2008, Compared to
Nine Months Ended September 30, 2007

Net Income

Net income for the nine months ended September 30, 2008, decreased $28 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($127 million) and increased interest expense ($2 million), partially offset by increased revenues ($84 million) and lower income taxes ($16 million) attributable to lower pre-tax income.

Revenues

Electric revenues in the nine months ended September 30, 2008, increased $29 million primarily due to:

- Increased wholesales sales ($32 million) due to increased wholesale market pricing and decreased native load
- Increased fuel costs billed to customers through the FAC ($17 million) due to increased fuel prices
- Increased ECR surcharge ($4 million) due to increased recoverable capital spending
- Increased demand charges ($4 million) due to higher peak load
- Decreased merger surcredit distribution to customers ($2 million)
- Decreased sales volumes to native load ($32 million) due in part to an 18% decrease in cooling degree days and outages related to damage from the Hurricane Ike wind storm

Natural gas revenues in the nine months ended September 30, 2008, increased $55 million primarily due to:

- Increased average cost of gas billed to retail customers ($47 million) due to increased gas costs
- Increased sales volumes ($8 million) due to a 5% increase in heating degree days

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expense. Increases or decreases in the cost of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission.

Fuel for electric generation increased $8 million in the nine months ended September 30, 2008, primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($17 million)
- Decreased generation ($9 million) due to decreased native load sales

Power purchased expense increased $13 million in the nine months ended September 30, 2008, primarily due to:

- Increased volumes purchased ($11 million) due to increased intercompany purchases as a result of lower KU native load due to milder weather and lower industrial sales
- Increased prices for purchases used to serve retail customers ($2 million)

Gas supply expense increased $57 million in the nine months ended September 30, 2008, primarily due to:

- Increased cost of net gas supply billed to customers ($61 million), primarily due to the commodity cost per Mcf
- Decreased costs ($4 million) due to decreased gas purchases for wholesale sales

Other operation and maintenance expense increased $48 million in the nine months ended September 30, 2008, primarily due to increased maintenance expense ($28 million) and increased other operation expense ($20 million).

Maintenance expense increased $28 million in the nine months ended September 30, 2008, primarily due to:

- Increased maintenance of overhead conductors and devices and tree trimming ($16 million) due to storm restoration
- Increased boiler and electric plant maintenance expense ($7 million) due to a scheduled outage and higher cost for outside contractors and material
- Increased distribution expense ($2 million) due to storm restoration
- Increased cost for other indirect maintenance ($2 million) due to increased software maintenance lease cost
- Increased steam expense ($1 million) due to high energy piping inspections and repairs

Other operation expense increased $20 million in the nine months ended September 30, 2008, primarily due to:

- Increased steam expense ($9 million) due to a non-recurring capital lease adjustment in 2007
- Increased distribution expense ($7 million) due to storm restoration
- Increased generation expense ($3 million) due to increased regional transmission organization charges primarily due to increased volume of transactions
- Increased cost of consumables ($1 million) due to contract pricing

Interest expense, including interest expense to affiliated companies, increased $2 million in the nine months ended September 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	0.9	3.6
Reduction of income tax reserve	(0.2)	(0.4)
Amortization of investment tax credits	(2.7)	(2.0)
Other differences	(1.9)	(3.5)
Effective income tax rate	31.1%	32.7%

The effective income tax rate decreased for the nine months ended September 30, 2008, compared to the nine months ended September 30, 2007, due primarily to a decrease in state income taxes net of federal benefit. State income taxes were favorably impacted by $5 million of coal and recycle credits recorded during the period. Amortization of investment tax credits increased due to the changes in levels of pretax income. These items were partially offset by various other differences.

Liquidity and Capital Resources

LG&E uses net cash generated from its operations, external financing (including financing from affiliates) and/or infusions of capital from its parent to fund construction of plant and equipment and the payment of dividends. LG&E currently has a working capital deficiency of $298 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $259 million. These bonds are being held until they can be refinanced or restructured. See Note 6 of Notes to Financial Statements. LG&E believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was $169 million and $128 million for the nine months ended September 30, 2008 and 2007, respectively.

The 2008 increase of $41 million was primarily the result of increases in cash due to changes in:

- Pension funding ($51 million) due to higher pension funding in 2007
- Accounts payable ($19 million)
- Fuel adjustment clause receivable, net ($12 million)
- Gas supply clause receivable ($8 million)
- Other current liabilities ($8 million)

These increases were partially offset by cash used by changes in:

- Materials and supplies ($30 million)
- Earnings, net of non-cash items ($18 million)

- Accounts receivable ($6 million)
- Other ($3 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $179 million and $137 million in the nine months ended September 30, 2008 and 2007, respectively. Net cash used for investing activities increased $18 million in the nine months ended September 30, 2008 compared to 2007, due to increased capital expenditures of $42 million, partially offset by an asset transferred to an affiliate of $10 million, proceeds from the sale of assets of $9 million, and cash provided by changes in long-term derivative liability (non-hedging) of $5 million.

Financing Activities

Net cash flows from financing activities were outflows of $14 million and inflows of $5 million in the nine months ended September 30, 2008 and 2007, respectively. Net cash provided by (used for) financing activities changed $19 million in the nine months ended September 30, 2008 compared to 2007, due to the reacquisition of bonds in the amount of $259 million, lower long-term borrowings from an affiliated company of $113 million and increased change in the mark-to-market of long-term derivative liability (cash flow hedge) of $4 million, partially offset by increased short-term borrowings from an affiliated company of $228 million, the retirement of preferred stock of $92 million in 2007, decreased dividend payments of $29 million and a change in restricted cash of $8 million.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

LG&E's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. LG&E expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $735 million, consisting primarily of construction of TC2 totaling approximately $85 million (including $25 million for environmental controls), gas main replacement initiatives of approximately $50 million, redevelopment of the Ohio Falls hydroelectric facility totaling approximately $45 million, a customer care system totaling approximately $30 million and on-going construction related to generation and distribution assets.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

LG&E has a variety of funding alternatives available to meet its capital requirements. LG&E

participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds of up to $400 million available to LG&E at market-based rates. Fidelia also provides long-term intercompany funding to LG&E. See Note 6 of Notes to Financial Statements.

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In November 2007, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds.

A significant portion of LG&E's short-term debt balance ($259 million) is related to the repurchase of auction rate tax-exempt bonds. Given the uncertainty surrounding the timing of when the bonds could be remarketed to the public due to the current state of the capital markets and the $400 million limit on short-term debt, the Company sought additional authority to issue long-term debt to reduce the existing short-term debt balances. In October 2008, the Kentucky Commission authorized the Company to issue up to $100 million of new long-term debt to its affiliate Fidelia. The Company currently believes this authorization provides the necessary flexibility to address any liquidity needs.

LG&E's debt ratings as of September 30, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework. The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2008, that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting.

LG&E is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Legal Proceedings

For a description of the significant legal proceedings involving LG&E, reference is made to the information under the following captions of LG&E's Financial Statements and Additional Information for the year ended December 31, 2007 (the "Annual Report"): Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in LG&E's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, LG&E believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on LG&E's financial position or results of operations.

FINANCIAL STATEMENTS

DECEMBER 31, 2008

Louisville Gas and Electric Company

Financial Statements and Additional Information

As of and For the Years Ended December 31, 2008 and 2007

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AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	LG&E
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation No.
FT and FT-A	Firm Transportation
GHG	Greenhouse Gas
GSC	Gas Supply Clause
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy LLC (now E.ON U.S. LLC)
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
MVA	Megavolt - ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NNS	No-Notice Service

NOx	Nitrogen Oxide
OVEC	Ohio Valley Electric Corporation
PBR	Performance-Based Ratemaking
PCB	Polychlorinated Biphenyl
PJM	PJM Interconnection
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Service
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
Tennessee Gas	Tennessee Gas Pipeline Company
Texas Gas	Texas Gas Transmission LLC
VDT	Value Delivery Team Process

Business

GENERAL

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 389,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in 9 counties. Natural gas service is provided to approximately 314,000 customers in its electric service area and 8 additional counties in Kentucky. Approximately 97% of the electricity generated by LG&E is produced by its coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

LG&E is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation. LG&E's affiliate, KU, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

OPERATIONS

For the year ended December 31, 2008, 69% of total operating revenues were derived from electric operations and 31% from natural gas operations. Electric and gas operating revenues and the percentages by class of service on a combined basis for this period were as follows:

(in millions)	Electric	Gas	Combined	% Combined
Residential	$ 301	$ 281	$ 582	40%
Industrial & Commercial	387	136	523	35%
Other Retail	76	20	96	7%
Wholesale	251	15	266	18%
Total	$1,015	$ 452	$1,467	100%

See Note 11 of Notes to Financial Statements for financial information concerning segments of business for the years ended December 31, 2008 and 2007.

ELECTRIC OPERATIONS

The sources of electric operating revenues and volumes of sales for the years ended December 31, 2008 and 2007, were as follows:

	2008		2007	
	Revenues (millions)	Volumes (Gwh)	Revenues (millions)	Volumes (Gwh)
Residential	$ 301	4,206	$ 309	4,486
Industrial & Commercial	387	6,574	382	6,830
Other Retail	76	1,303	75	1,342
Wholesale	251	7,884	167	6,186
Total	$1,015	19,967	$ 933	18,844

LG&E's peak electric load in 2008 was 2,502 Mw on September 2, 2008, when the temperature reached 94 degrees Fahrenheit in Louisville.

The Company's power generating system includes coal-fired units operated at its three steam generating stations. Natural gas and oil fueled CTs supplement the system during peak or emergency periods. As of December 31, 2008, LG&E owned and operated the following electric generating stations while maintaining a 13%-15% reserve margin:

	Summer Capability Rating (Mw)
Steam Stations:	
Mill Creek – Jefferson County, KY	1,472
Cane Run – Jefferson County, KY	563
Trimble County – Trimble County, KY (a)	383
Total Steam Stations	2,418
Ohio Falls Hydroelectric Station – Jefferson County, KY	52
CT Generators (Peaking capability):	
Zorn – Jefferson County, KY	14
Paddy's Run – Jefferson County, KY (b)	119
Cane Run – Jefferson County, KY	14
E.W. Brown – Mercer County, KY (b)	190
Trimble County – Trimble County, KY (b)	328
Total CT Generators	665
Total Capability Rating	3,135

(a) Amount shown represents LG&E's 75% interest. See Note 10 of Notes to Financial Statements for information regarding jointly owned units.
(b) Some of these units are jointly owned with KU. See Note 10 of Notes to Financial Statements for information regarding jointly owned units.

At December 31, 2008, LG&E's electric transmission system included 42 substations (30 of which are shared with the distribution system) with a total capacity of approximately 11,820 MVA and approximately 894 miles of lines. The electric distribution system included 93 substations (30 of which are shared with the transmission system) with a total capacity of approximately 5,060 MVA, 3,926 miles of overhead lines and 2,327 miles of underground conduit.

LG&E has contracts with the Tennessee Valley Authority to act as its transmission reliability coordinator and Southwest Power Pool, Inc. to function as its independent transmission operator, pursuant to FERC requirements. See Note 2 of Notes to Financial Statements.

GAS OPERATIONS

The sources of natural gas operating revenues and the sales volumes for the years ended December 31, 2008 and 2007, were as follows:

	2008		2007	
	Revenues (millions)	Volumes (MMcf)	Revenues (millions)	Volumes (MMcf)
Residential	$ 281	21,338	$ 218	19,811
Industrial & Commercial	136	10,914	101	10,182
Other Retail	20	1,677	15	1,553
Wholesale	15	12,241	19	13,575
Total	$ 452	46,170	$ 353	45,121

LG&E's natural gas transmission system includes 256 miles of transmission mains and the natural gas distribution system includes 4,235 miles of distribution mains.

The natural gas utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. LG&E gas billings include a Weather Normalization Adjustment ("WNA") mechanism which adjusts the distribution cost component of the natural gas billings of residential and commercial customers to normal temperatures during the heating season months of November through April, somewhat mitigating the effect of above- or below-normal weather on residential and commercial revenues. In October 2006, the Kentucky Commission approved LG&E's request to extend the current WNA mechanism through April 30, 2009.

Five underground natural gas storage fields, with a current working gas capacity of approximately 15 million Mcf, help provide economical and reliable natural gas service to ultimate consumers. By using natural gas storage facilities, LG&E avoids the costs associated with typically more expensive pipeline transportation capacity to serve peak winter space-heating loads. Natural gas is stored in the summer season for withdrawal in the subsequent winter heating season. Without its storage capacity, LG&E would be forced to buy additional natural gas and pipeline transportation services during the winter months when customer demand increases and when the prices for natural gas supply and transportation services are typically at their highest. Several suppliers under contracts of varying duration provide competitively priced natural gas. The underground storage facilities, in combination with its purchasing practices, enable the Company to offer natural gas sales service at competitive rates. At December 31, 2008, LG&E had an 11 million Mcf inventory balance of natural gas stored underground valued at $112 million.

A number of large commercial and industrial customers purchase their natural gas requirements directly from alternate suppliers for delivery through LG&E's distribution system. These large commercial and industrial customers account for approximately one-fourth of the Company's annual throughput.

The estimated maximum deliverability from storage during the early part of the heating season is expected to be in excess of 350,000 Mcf/day. Under mid-winter design conditions, LG&E expects to be able to withdraw about 300,000 Mcf/day from its storage facilities. The deliverability of natural gas from the storage facilities decreases as storage inventory levels are reduced by seasonal withdrawals.

During 2008, the maximum daily gas sendout was approximately 443,000 Mcf, occurring on January 24, 2008, when the average temperature for the day in Louisville was 15 degrees Fahrenheit. Supply on that day consisted of approximately 240,000 Mcf from pipeline deliveries, approximately 127,000 Mcf delivered from underground storage and approximately 76,000 Mcf transported for large commercial and industrial customers.

RATES AND REGULATIONS

E.ON, LG&E's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including LG&E, and certain of its non-utility subsidiaries are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. LG&E believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

In April 2007, LG&E completed a series of financial transactions that allowed it to cease periodic reporting under the Securities Exchange Act of 1934. See Note 7 of Notes to Financial Statements.

The Company is subject to the jurisdiction of the Kentucky Commission and the FERC in virtually all matters related to electric and gas utility regulation, and as such, its accounting is subject to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. Given its competitive position in the marketplace and the status of regulation in Kentucky, there are no plans or intentions to discontinue the application of SFAS No. 71.

In July 2008, LG&E filed an application with the Kentucky Commission requesting increases in base electric and gas rates. In conjunction with the filing of the application for changes in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008. In January 2009, LG&E, the AG, KIUC and all other parties to the rate cases filed a settlement agreement with the Kentucky Commission, under which LG&E's base gas rates will increase by $22 million annually, and base electric rates will decrease by $13 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated. (See Notes 2 and 14 of Notes to Financial Statements)

In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through the service territory causing significant outages and system damage. In October 2008, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $24 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $24 million based on its actual costs for storm damages and service restoration due to the wind storm.

In January 2009, a significant winter ice storm passed through LG&E's service territory causing approximately 205,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 37,000 customer outages. LG&E currently estimates costs incurred of $34 million of expenses and $6 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

For a further discussion of regulatory matters, see Notes 2 and 9 of Notes to Financial Statements.

COAL SUPPLY

Coal-fired generating units provided approximately 97% of LG&E's net Kwh generation for 2008. The remaining net generation for 2008 was provided by natural gas and oil fueled CT peaking units and a hydroelectric plant. Coal is expected to be the predominant fuel used by LG&E in the foreseeable future, with natural gas and oil being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected from time to time by a number of factors, including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

LG&E has entered into coal supply agreements with various suppliers for coal deliveries for 2009 and beyond and normally augments its coal supply agreements with spot market purchases. The Company has a coal inventory policy which it believes provides adequate protection under most contingencies.

LG&E expects to continue purchasing most of its coal, which has sulfur content in the 2.0% - 3.5% range, from western Kentucky, southern Indiana, southern Illinois, Ohio and West Virginia for the foreseeable future. This supply, in combination with the Company's SO_2 removal systems, is expected to enable LG&E to continue to provide electric service in compliance with existing environmental laws and regulations. Coal is delivered to LG&E's generating stations by a mix of transportation modes including rail and barge.

GAS SUPPLY

LG&E purchases natural gas supplies from multiple sources under contracts for varying periods of time, while transportation services are purchased from Texas Gas and Tennessee Gas.

LG&E currently transports natural gas on the Texas Gas system under Rate Schedules NNS and FT service. LG&E's total winter season NNS capacity is 184,900 MMBtu/day and its total summer season NNS capacity is 60,000 MMBtu/day. There are three separate NNS agreements with Texas Gas which are subject to termination by LG&E in equal amounts during 2010, 2011 and 2013. LG&E's total winter and summer season FT capacity with Texas Gas is 10,000 MMBtu/day and is under a single FT agreement. The FT agreement is subject to termination by LG&E during 2011. Effective November 1, 2008, LG&E contracted for transportation service with Texas Gas under Rate Schedule Short-Term Firm with a winter season capacity of 100 MMBtu/day and a summer season capacity of 18,000 MMBtu/day. This new Short-Term Firm agreement is subject to termination by LG&E during 2013. LG&E also transports on the Tennessee Gas system under Tennessee Gas' Rate Schedule FT-A. LG&E's contract capacity with Tennessee Gas is 51,000 MMBtu/day throughout the year (winter and summer seasons). The FT-A agreement with Tennessee Gas expires during 2012.

LG&E participates in rate and other proceedings affecting the regulated interstate natural gas pipelines that provide it service. Both Texas Gas and Tennessee Gas have active proceedings at the FERC in which LG&E is participating. However, neither pipeline is currently billing charges subject to refund, and neither currently has rate case proceedings before the FERC that would reasonably be expected to materially change the pipeline's base transportation rates under which LG&E receives service.

The Company also has a portfolio of supply arrangements of various terms with a number of suppliers designed to meet its firm sales obligations. These natural gas supply arrangements include pricing provisions that are market-responsive. In tandem with pipeline transportation services, these natural gas supplies provide the reliability and flexibility necessary to serve LG&E's natural gas customers.

For discussion of wholesale natural gas prices, see Note 2 of Notes to Financial Statements.

ENVIRONMENTAL MATTERS

Protection of the environment is a major priority for LG&E. Federal, state and local regulatory agencies have issued the Company permits for various activities subject to air quality, water quality and waste management laws and regulations. LG&E is also subject to extensive existing or potential environmental regulation. See Note 9 of Notes to Financial Statements for additional information.

STATE ENERGY POLICY

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet
- Increase Kentucky's use of renewable energy
- Sustainably grow Kentucky's production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase gas supplies, including coal-to-gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

Legislative and regulatory actions as a result of these proposals and their impact on LG&E, which may be significant, cannot currently be predicted.

COMPETITION

At this time, neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of the ultimate legislative or regulatory actions regarding industry restructuring and their impact on LG&E, which may be significant, cannot currently be predicted. See Note 2 of Notes to Financial Statements for additional information.

EMPLOYEES AND LABOR RELATIONS

LG&E had 996 full-time regular employees at December 31, 2008, 679 of which were operating, maintenance and construction employees represented by the IBEW Local 2100. The Company and employees represented by the IBEW Local 2100 signed a three-year collective bargaining agreement in November 2008. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions.

OFFICERS OF THE COMPANY

At December 31, 2008:

Name	Age	Position	Effective Date of Election to Present Position
Victor A. Staffieri	53	Chairman of the Board, President and Chief Executive Officer	May 2001
John R. McCall	65	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994
S. Bradford Rives	50	Chief Financial Officer	September 2003
Chris Hermann	61	Senior Vice President – Energy Delivery	February 2003
Paula H. Pottinger	51	Senior Vice President – Human Resources	January 2006
Paul W. Thompson	51	Senior Vice President – Energy Services	June 2000
Wendy C. Welsh	54	Senior Vice President – Information Technology	December 2000
Michael S. Beer	50	Vice President – Federal Regulation and Policy	September 2004
Lonnie E. Bellar	44	Vice President – State Regulation and Rates	August 2007
Kent W. Blake	42	Vice President – Corporate Planning and Development	August 2007
D. Ralph Bowling	51	Vice President – Power Production	June 2008
Laura G. Douglas	59	Vice President – Corporate Responsibility and Community Affairs	November 2007
R. W. Chip Keeling	52	Vice President – Communications	March 2002
John P. Malloy	47	Vice President – Energy Delivery – Retail Business	April 2007
Dorothy E. O'Brien	55	Vice President and Deputy General Counsel – Legal and Environmental Affairs	October 2007
George R. Siemens	59	Vice President – External Affairs	January 2001
David S. Sinclair	47	Vice President – Energy Marketing	January 2008
P. Greg Thomas	52	Vice President – Energy Delivery – Distribution Operations	April 2007
John N. Voyles, Jr.	54	Vice President – Transmission & Generation Services	June 2008
Daniel K. Arbough	47	Treasurer	December 2000
Valerie L. Scott	52	Controller	January 2005

Officers generally serve in the same capacities at LG&E and its affiliates, E.ON U.S. and KU.

Risk Factors

LG&E is subject to a number of risks, including without limitation, those listed below and elsewhere in this document. Such risks could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by LG&E.

The electric and gas rates that LG&E charges customers, as well as other aspects of the business, are subject to significant and complex governmental regulation. Federal and state entities regulate many aspects of utility operations, including financial and capital structure matters; siting and construction of facilities; rates, terms and conditions of service and operations; mandatory reliability and safety standards; accounting and cost allocation methodologies; tax matters; acquisition and disposal of utility assets and securities and other matters. Such regulations may subject LG&E to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge LG&E's rate request and ultimately reduce, alter or limit the rates LG&E seeks.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues. The resulting changes to transmission and wholesale power market structures and prices are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which LG&E participates.

Transmission and interstate market activities of LG&E, as well as other aspects of the business, are subject to significant FERC regulation. LG&E's business is subject to extensive regulation under the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions; certain natural gas operations and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of LG&E.

LG&E undertakes significant capital projects and is subject to unforeseen costs, delays or failures in such projects, as well as risk of full recovery of such costs. The completion of these facilities without delays or cost overruns is subject to risks in many areas including approval and licensing; permitting; land acquisition; construction problems or delays; increases in commodity prices or labor rates; contractor performance; weather and geological issues and political, labor and regulatory developments.

LG&E's costs of compliance with environmental laws are significant and are subject to continuing changes. Extensive federal, state and local environmental regulations are applicable to LG&E's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions.

LG&E's operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters. These weather or man-made factors can significantly affect LG&E's

finances or operations by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets or impacting future growth.

LG&E is subject to risks regarding potential developments concerning global climate change matters. Such developments could include potential federal or state legislation or industry initiatives limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. LG&E's generation fleet is predominantly coal-fired and may be highly impacted by developments in this area.

LG&E's business is subject to risks associated with local, national and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption and slower customer growth, which may adversely affect LG&E's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and LG&E's ability to raise capital. A deterioration of economic conditions may lead to decreased production by LG&E's industrial customers and, therefore, lower consumption of electricity and gas. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

LG&E's business is concentrated in the Midwest United States, specifically Kentucky. Local and regional economic conditions, such as population growth, industrial growth or expansion and economic development, as well as the operational or financial performance of major industries or customers, can affect the demand for energy. Significant activities in LG&E's service territory include airport and logistics activities; automotive; chemical and rubber processing; educational institutions; health care facilities; metal fabrication and water and sewer utilities.

LG&E is subject to operational risks relating to its generating plants, transmission facilities and distribution equipment. Operation of power plants and transmission and distribution facilities subjects LG&E to many risks, including the breakdown or failure of equipment; accidents; labor disputes; delivery/transportation problems; disruptions of fuel supply and performance below expected levels.

LG&E could be negatively affected by rising interest rates, downgrades to company or bond insurer credit ratings that could impact the Company's bond credit ratings or other negative developments in its ability to access capital markets. In the ordinary course of business, LG&E is reliant upon adequate long-term and short-term financing means to fund its significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, LG&E is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs to LG&E.

LG&E is subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business. General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to LG&E.

LG&E is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters. Risks include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. The Company is also subject to risk related to changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

LG&E is subject to risks associated with federal and state tax regulations. Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact LG&E's results of operations. LG&E is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. LG&E also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which LG&E operates, various tax and fee increases may be proposed or considered. LG&E cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on LG&E's results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including electric and natural gas base rate increase proceedings, TC2 proceedings, Kentucky Commission, FERC proceedings and other rates or regulatory matters affecting LG&E, see Notes 2 and 9 of Notes to Financial Statements.

Environmental

For a discussion of environmental matters including additional reductions in SO_2, NOx and other emissions mandated by recent or potential regulations; items regarding other emissions proceedings and the manufactured gas plant sites; global warming or climate change matters and other environmental items affecting LG&E, see Note 9 of Notes to Financial Statements.

Litigation

For a discussion of litigation matters, see Note 9 of Notes to Financial Statements.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, the Company believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on LG&E's financial position or results of operations.

Selected Financial Data

(in millions)	Years Ended December 31				
	2008	2007	2006	2005	2004
Operating revenues	$ 1,467	$ 1,286	$ 1,338	$ 1,424	$ 1,173
Net operating income	$ 219	$ 230	$ 223	$ 230	$ 185
Net income	$ 90	$ 120	$ 117	$ 129	$ 96
Total assets	$ 3,637	$ 3,313	$ 3,184	$ 3,146	$ 2,967
Long-term obligations (including amounts due within one year)	$ 896	$ 984	$ 820	$ 821	$ 872

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during 2008 and 2007 and should be read in connection with the financial statements and notes thereto.

Forward Looking Statements

Some of the following discussion may contain forward-looking statements that are subject to risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may materially vary. Factors that could cause actual results to materially differ include, but are not limited to: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; actions by credit rating agencies and other factors described from time to time in LG&E's reports, including those noted in the Risk Factors section of this report.

RESULTS OF OPERATIONS

The electric and gas utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Net Income

Net income related to the electric business decreased $30 million, while net income related to the natural gas business did not fluctuate during 2008 compared to 2007, resulting in an overall $30 million net income decrease. The decrease was primarily the result of increased operating expenses ($192 million), increased other expense-net ($34 million) and increased interest expense ($3 million), partially offset by increased gas and electric revenues ($99 million and $82 million, respectively) and decreased income taxes ($18 million).

Revenues

Electric revenues in 2008 increased $82 million primarily due to:

- Increased wholesale sales ($84 million) due to higher sales volumes with third-parties ($60 million) and KU ($8 million), as a result of excess generation made available by KU via a mutual agreement. LG&E sells its lower cost electricity to KU to serve its native load and purchases KU's excess economic capacity for wholesale sales. Both LG&E and KU experienced lower native load requirements due to milder weather and the weakening economy resulting in higher volumes available for wholesale sales. Wholesale sales also increased due to higher fuel costs for sales to KU ($8 million) and gains in energy marketing financial swaps ($8 million).
- Increased fuel costs billed to customers through the FAC ($16 million) due to increased fuel prices
- Increased ECR surcharge ($6 million) due to increased recoverable capital spending
- Decreased merger surcredit ($3 million) due to a lower rate approved by the Kentucky Commission in June 2008
- Increased DSM cost recovery ($2 million) due to additional conservation programs
- Decreased VDT surcredit ($2 million) due to its termination in August 2008
- Decreased retail sales volumes delivered ($31 million) due to a 21% decrease in cooling

degree days and weakening economic conditions

Natural gas revenues in 2008 increased $99 million primarily due to:

- Increased average cost of gas billed to retail customers through the GSC ($76 million) due to increased natural gas supply costs
- Increased sales volumes ($23 million) due to a 12% increase in heating degree days

Expenses

Fuel for electric generation and natural gas supply expenses comprise a large component of total operating expenses. Increases or decreases in the cost of fuel and natural gas supply are reflected in electric and natural gas retail rates, through the FAC and GSC, subject to the approval of the Kentucky Commission.

Fuel for electric generation increased a net $27 million in 2008 primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($28 million)
- Decreased volumes of natural gas usage ($1 million) due to decreased native load sales

Power purchased expense increased $36 million in 2008 primarily due to:

- Increased purchase volumes from KU via a mutual agreement ($34 million) whereby LG&E purchases KU's excess economic capacity for wholesales sales. KU experienced lower native load requirements as a result of milder weather and the weakening economy and increased generation availability.
- Increased prices for third-party purchases used to serve native load ($3 million) during unit outages due to higher fuel costs
- Increased expenses ($2 million) due to activities in the PJM market for the entire year of 2008 compared to only one quarter in 2007
- Decreased demand costs ($3 million) for energy purchased on a long-term contract

Gas supply expenses increased $93 million in 2008 due to:

- Increased cost of net gas supply billed to customers ($97 million) due to higher purchased volumes and cost per Mcf
- Decreased expense ($4 million) due to a decline in volume of wholesale sales of purchased gas

Other operation and maintenance expenses increased $35 million in 2008 primarily due to increased other operation expenses ($23 million) and increased maintenance expenses ($12 million).

Other operation expenses increased $23 million in 2008 primarily due to:

- Increased steam expense ($5 million) due to a non-recurring capital lease adjustment in 2007
- Increased other power supply expense ($5 million) due to a FERC Order resulting in additional MISO RSG resettlement costs and activities in the PJM market for the entire year of 2008 compared to only one quarter in 2007
- Increased cost of consumables ($4 million) due to contract pricing
- Increased transmission expense paid to KU ($3 million) due to increased firm transmission purchases and increased transmission rates
- Increased distribution expense ($2 million) due to storm restoration
- Increased uncollectible accounts ($2 million) due to the weakening economy
- Increased property taxes ($2 million) due to net decrease in expense in 2007 as a result of the

application of coal tax credits

Maintenance expenses increased $12 million in 2008 primarily due to:

- Increased scheduled outage expense ($3 million)
- Increased maintenance of overhead conductors and devices ($3 million) due to storm restoration
- Increased gas distribution expense ($2 million) due to gas main maintenance
- Increased cost for other indirect maintenance ($2 million) due to increased software maintenance lease cost, maintenance fees and labor support
- Increased steam and boiler plant maintenance expense ($2 million) due to increased high energy piping inspections and repairs, scheduled outages, mill overhauls and barge unloading maintenance

Other expense – net increased $34 million in 2008 primarily due to increased expense related to ineffective interest rate swaps ($42 million), partially offset by the gain on the sale of the Company's Waterside property to the Louisville Arena Authority ($9 million). See Note 2 of Notes to Financial Statements.

Interest expense increased $3 million in 2008 primarily due to increased interest expense to affiliated companies ($8 million) due to additional debt, partially offset by decreased interest expense ($5 million) due to interest received on reacquired debt ($4 million) and a terminated cash flow hedge ($1 million).

CRITICAL ACCOUNTING POLICIES/ESTIMATES

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. Specific risks for these critical accounting policies are described in the Notes to Financial Statements. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Events rarely develop exactly as forecasted and the best estimates routinely require adjustment.

Critical accounting policies and estimates including unbilled revenue, allowance for doubtful accounts, regulatory mechanisms, pension and postretirement benefits and income taxes are detailed in Notes 1, 2, 5, 6 and 9 of Notes to Financial Statements.

Recent Accounting Pronouncements. Recent accounting pronouncements affecting LG&E are detailed in Note 1 of Notes to Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

LG&E uses net cash generated from its operations, external financing (including financing from affiliates) and/or infusions of capital from its parent mainly to fund construction of plant and equipment and the payment of dividends. As of December 31, 2008, LG&E had a working capital deficiency of $144 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $163 million, and $120 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term debt. The repurchased bonds are being held until they can be refinanced or restructured. See Note 7 of Notes to Financial Statements. LG&E believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

E.ON U.S. and LG&E sponsor pension plans and E.ON U.S. sponsors a postretirement benefit plan for their employees. The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The market value of the combined investments within the plans declined by approximately 29% for the year ended December 31, 2008 due to the recent volatility in the capital markets. The benefit plan assets and obligations of E.ON U.S. and LG&E are remeasured annually using a December 31 measurement date. Investment losses resulted in an increase to the plans' unfunded status upon actuarial revaluation of the plans. Changes in the value of plan assets did not impact the income statement for 2008; however, reduced benefit plan assets will result in increased benefit costs in future years and may increase the amount, and accelerate the timing of, required future funding contributions. The Company anticipates its 2009 pension cost will be approximately $25 million higher than 2008. The amount of future funding will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The amount of such contributions cannot be determined at this time.

Operating Activities

The 2008 net increase in cash provided by operations was $25 million and was primarily the result of increases in cash due to changes in:

- Pension and postretirement funding ($56 million) due to a contribution made in 2007
- Accrued income taxes ($34 million) primarily due to the timing of tax payments
- Gas supply clause receivable ($34 million) due to the timing of GSC collections
- Prepaid pension asset ($28 million) due to market conditions resulting in a liability
- Other current assets and liabilities ($4 million)
- Change in collateral deposit ($2 million)

These increases were partially offset by cash used by changes in:

- Earnings, net of non-cash items ($64 million)
- Materials and supplies ($29 million) due to higher gas cost per Mcf
- Wind storm regulatory asset ($24 million) due to new regulatory asset for Hurricane Ike restoration expenses
- Accounts receivable ($9 million) primarily due to increased heating degree days
- Accounts payable ($4 million)
- Change in hedging derivative liability ($3 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Net cash used for investing activities increased $2 million in 2008 compared to 2007, primarily due to increased capital expenditures of $42 million and a change in restricted cash ($9 million), partially offset by increased non-hedging derivative liability ($30 million), an asset transferred to KU ($10 million) and proceeds from the sale of the Waterside property ($9 million). See Note 2 of Notes to Financial Statements.

Financing Activities

Net cash provided by financing activities decreased $20 million, due to the reacquisition of bonds of $259 million, an issuance of pollution control bonds in 2007 of $125 million and lower long-term borrowings from an affiliated company of $110 million, partially offset by net increased short-term borrowings from an affiliated company of $134 million, the retirement of first mortgage bonds in 2007 of $126 million, the reissuance of reacquired bonds of $95 million, the retirement of preferred stock of $90 million in 2007 and decreased dividend payments of $29 million.

See Note 7 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

LG&E's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric and gas needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. LG&E expects its capital expenditures for the three-year period ending December 31, 2011 to total approximately $690 million, consisting primarily of on-going construction related to distribution assets totaling approximately $345 million, on-going construction related to generation assets totaling approximately $240 million, redevelopment of the Ohio Falls hydroelectric facility totaling approximately $35 million, construction of TC2 totaling approximately $35 million (including $5 million for environmental controls), and information technology projects of approximately $35 million. See Note 9 of Notes to Financial Statements for additional information.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See the Contractual Obligations table below and Note 9 of Notes to Financial Statements for current commitments. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

LG&E has a variety of funding alternatives available to meet its capital requirements. LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds of up to $400 million available to the Company at market-based rates. Fidelia also provides long-term intercompany funding to LG&E. See Notes 7 and 8 of Notes to Financial Statements.

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes issuance of long-term debt. In November 2007, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. As of December 31, 2008, LG&E has borrowed $222 million of this authorized amount. See Note 8 of Notes to Financial Statements.

A significant portion of LG&E's short-term debt balance ($163 million) is for borrowings incurred to repurchase auction rate tax-exempt bonds. Following the repurchase, the auction rate tax-exempt bonds have been removed from the balance sheet. However, these bonds are being held until they can be refinanced or restructured. Given the uncertainty surrounding the timing of when the bonds could be remarketed to the public due to the current state of the capital markets and the $400 million limit on short-term debt, in October 2008, the Company sought and received authority from the Kentucky Commission to issue up to $100 million of new long-term debt to its affiliate, Fidelia. The Company currently believes this authorization provides the necessary flexibility to address any liquidity needs.

LG&E's debt ratings as of December 31, 2008, were:

	Moody's	S&P
Unenhanced pollution control revenue bonds	A2	BBB+
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 7 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2008. LG&E anticipates cash from operations and external financing will be sufficient to fund future obligations. See Statements of Capitalization.

(in millions)	Payments Due by Period						
Contractual Cash Obligations	2009	2010	2011	2012	2013	Thereafter	Total
Short-term debt (a)	$ 222	$ -	$ -	$ -	$ -	$ -	$ 222
Long-term debt	-	-	-	25	200	671 (b)	896
Interest on long-term debt to affiliated company (c)	27	27	26	26	21	204	331
Interest on fixed rate bonds (d)	8	8	8	7	5	54	90
Operating leases (e)	9	5	4	3	4	5	30
Unconditional power purchase obligations (f)	20	21	21	23	23	349	457
Coal and gas purchase obligations (g)	307	309	308	123	63	-	1,110
Postretirement benefit plan obligations (h)	7	7	8	8	8	37	75
Other obligations (i)	37	2	-	-	-	-	39
Total contractual cash obligations	$ 637	$ 379	$ 375	$ 215	$ 324	$ 1,320	$ 3,250

(a) Represents borrowings from affiliated company due within one year including $163 million used to acquire long-term debt issued by the Company.
(b) Includes long-term debt of $120 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2026 to 2027. Reacquired bonds totaling $163 million are excluded.
(c) Represents future interest payments on long-term debt to affiliated company.
(d) Represents interest on fixed rate long-term bonds. Future interest obligations on variable rate long-term bonds cannot be quantified.
(e) Represents future operating lease payments.
(f) Represents future minimum payments under OVEC power purchase agreements through 2026.
(g) Represents contracts to purchase coal, natural gas and natural gas transportation. Obligations for 2014 and 2015 are indexed to future market prices and will not be included above until prices are set using the contracted methodology.
(h) Represents currently projected cash flows for the postretirement benefit plan as calculated by the actuary. For pension funding information see Note 5 of Notes to Financial Statements.
(i) Represents construction commitments, including commitments for TC2.

CONTROLS AND PROCEDURES

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

LG&E is not subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently is not required to evaluate the effectiveness of the Company's internal control over financial reporting pursuant to Section 404 of the Act. However, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008 using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Management has concluded that, as of December 31, 2008, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2008 LG&E financial statements and additional information.

Louisville Gas and Electric Company
Statements of Income
(Millions of $)

	Years Ended December 31	
	2008	2007
OPERATING REVENUES:		
Electric (Note 12)	$1,015	$ 933
Gas	452	353
Total operating revenues	1,467	1,286
OPERATING EXPENSES:		
Fuel for electric generation	345	318
Power purchased (Notes 9 and 12)	118	82
Gas supply expenses	347	254
Other operation and maintenance expenses	311	276
Depreciation and amortization (Note 1)	127	126
Total operating expenses	1,248	1,056
Net operating income	219	230
Other expense - net	35	1
Interest expense (Notes 7 and 8)	24	29
Interest expense to affiliated companies (Note 12)	29	21
Income before income taxes	131	179
Federal and state income taxes (Note 6)	41	59
Net income	$ 90	$ 120

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Millions of $)

	Years Ended December 31	
	2008	2007
Balance January 1	$ 690	$ 639
Add net income	90	120
Preferred stock buyback	-	(4)
	780	755
Deduct cash dividends declared on common stock	40	65
Balance December 31	$ 740	$ 690

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(Millions of $)

	Years Ended December 31 2008	2007
Net income	$ 90	$ 120
Gain (loss) on derivative instruments and hedging activities, net of tax benefit of $0 and $2 for 2008 and 2007, respectively (Notes 1 and 3)	(1)	(4)
Comprehensive income	$ 89	$ 116

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets
(Millions of $)

	December 31 2008	December 31 2007
ASSETS:		
Current assets:		
Cash and cash equivalents (Note 1)	$ 4	$ 4
Restricted cash (Note 1)	2	7
Accounts receivable - less reserve of $2 million in 2008 and 2007 (Notes 1 and 12)	203	189
Materials and supplies (Note 1):		
Fuel (predominantly coal)	51	46
Gas stored underground	112	81
Other materials and supplies	32	31
Prepayments and other current assets	7	13
Total current assets	411	371
Utility plant, at original cost (Note 1):		
Electric	3,343	3,246
Gas	599	551
Common	190	178
Total utility plant, at original cost	4,132	3,975
Less: reserve for depreciation	1,690	1,619
Total utility plant, net	2,442	2,356
Construction work in progress	374	344
Total utility plant and construction work in progress	2,816	2,700
Deferred debits and other assets:		
Restricted cash (Note 1)	22	12
Prepaid pension assets	-	14
Regulatory assets (Note 2):		
Pension and postretirement benefits	250	110
Other	132	94
Other assets	6	12
Total deferred debits and other assets	410	242
Total Assets	$ 3,637	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (continued)
(Millions of $)

	December 31 2008	December 31 2007
LIABILITIES AND EQUITY:		
Current liabilities:		
Current portion of long-term debt (Note 7)	$ 120	$ 120
Notes payable to affiliated companies (Notes 8 and 12)	222	78
Accounts payable	110	111
Accounts payable to affiliated companies (Note 12)	38	57
Customer deposits	22	19
Other current liabilities	43	34
Total current liabilities	555	419
Long-term debt:		
Long-term bonds (Note 7)	291	454
Long-term debt to affiliated company (Note 7)	485	410
Total long-term debt	776	864
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 6)	342	342
Accumulated provision for pensions and related benefits (Note 5)	225	94
Investment tax credit (Note 6)	50	46
Asset retirement obligations	31	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	251	241
Deferred income taxes	45	50
GSC and other	46	19
Derivative liability (Note 3)	55	22
Other liabilities	27	25
Total deferred credits and other liabilities	1,072	869
Commitments and contingencies (Note 9)		
COMMON EQUITY:		
Common stock, without par value - Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital (Note 12)	84	60
Accumulated other comprehensive income (Note 13)	(14)	(13)
Retained earnings	740	690
Total common equity	1,234	1,161
Total Liabilities and Equity	$ 3,637	$ 3,313

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows
(Millions of $)

	Years Ended December 31 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 90	$ 120
Items not requiring cash currently:		
Depreciation and amortization	127	126
Deferred income taxes - net	(5)	12
Investment tax credit - net	4	5
Gain from disposal of asset	(9)	-
Provision for pension and postretirement plans	(1)	11
Other	2	(2)
Change in certain current assets and liabilities:		
Accounts receivable	(14)	(5)
Materials and supplies	(37)	(8)
Accounts payable	(1)	3
Accrued income taxes	13	(21)
Prepaid pension asset	14	(14)
Other current assets and liabilities	1	(3)
Pension and postretirement funding	(7)	(63)
Gas supply clause receivable, net	13	(21)
Change in hedging derivative liability	3	6
Change in collateral deposit – interest rate swap	(10)	(12)
Wind storm regulatory asset	(24)	-
Other	2	2
Net cash provided by operating activities	161	136
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(245)	(203)
Assets transferred to affiliate	10	-
Proceeds from sale of asset	9	-
Change in non-hedging derivative liability	30	-
Change in restricted cash	-	9
Net cash used for investing activities	(196)	(194)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings from affiliated company (Note 7)	75	185
Short-term borrowings from affiliated company (Note 8)	320	134
Repayment of short-term borrowings from affiliated company	(176)	(124)
Retirement of first mortgage bonds	-	(126)
Issuance of pollution control bonds	-	125
Acquisition of outstanding bonds	(259)	-
Reissuance of reacquired bonds	95	-
Retirement of preferred stock	-	(90)
Payment of dividends	(40)	(69)
Additional paid-in capital	20	20
Net cash provided by financing activities	35	55
Change in cash and cash equivalents	-	(3)
Cash and cash equivalents at beginning of year	4	7
Cash and cash equivalents at end of year	$ 4	$ 4
Supplemental disclosures of cash flow information:		
Cash paid during the year for:		
Income taxes	$ 34	$ 62
Interest on borrowed money	20	24
Interest to affiliated companies on borrowed money	22	15

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Capitalization
(Millions of $)

	December 31 2008	December 31 2007
LONG-TERM DEBT (Note 7):		
Pollution control series:		
Jefferson Co. 2000 Series A, due May 1, 2027, 5.375%	$ 25	$ 25
Trimble Co. 2000 Series A, due August 1, 2030, variable %	83	83
Jefferson Co. 2001 Series A, due September 1, 2027, variable %	10	10
Jefferson Co. 2001 Series A, due September 1, 2026, variable %	22	22
Trimble Co. 2001 Series A, due September 1, 2026, variable %	28	28
Jefferson Co. 2001 Series B, due November 1, 2027, variable %	35	35
Trimble Co. 2001 Series B, due November 1, 2027, variable %	35	35
Trimble Co. 2002 Series A, due October 1, 2032, variable %	42	42
Louisville Metro 2003 Series A, due October 1, 2033, variable %	128	128
Louisville Metro 2005 Series A, due February 1, 2035, 5.75%	40	40
Trimble Co. 2007 Series A, due June 1, 2033, 4.60%	60	60
Louisville Metro 2007 Series A, due June 1, 2033, 5.625%	31	31
Louisville Metro 2007 Series B, due June 1, 2033, variable %	35	35
Total pollution control series	574	574
Notes payable to Fidelia:		
Due January 16, 2012, 4.33%, unsecured	25	25
Due April 30, 2013, 4.55%, unsecured	100	100
Due August 15, 2013, 5.31%, unsecured	100	100
Due November 23, 2015, 6.48%, unsecured	50	-
Due July 25, 2018, 6.21%, unsecured	25	-
Due November 26, 2022, 5.72%, unsecured	47	47
Due April 13, 2031, 5.93%, unsecured	68	68
Due April 13, 2037, 5.98 %, unsecured	70	70
Total notes payable to Fidelia	485	410
Total long-term debt outstanding	1,059	984
Less reacquired debt	163	-
Less current portion of long-term debt	120	120
Long-term debt	776	864
COMMON EQUITY:		
Common stock, without par value -		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital (Note 12)	84	60
Accumulated other comprehensive income (Note 13)	(14)	(13)
Retained earnings	740	690
Total common equity	1,234	1,161
Total capitalization	$ 2,010	$ 2,025

The accompanying notes are an integral part of these financial statements.

Note 1 - Summary of Significant Accounting Policies

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 389,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in 9 counties. Natural gas service is provided to approximately 314,000 customers in its electric service area and 8 additional counties in Kentucky. Approximately 97% of the electricity generated by LG&E is produced by its coal-fired generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs.

LG&E is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation. LG&E's affiliate, KU, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

Regulatory Accounting. LG&E is subject to SFAS No. 71, under which regulatory assets are created based on expected recovery from customers in future rates to defer costs that would otherwise be charged to expense. Likewise, regulatory liabilities are created based on expected return to customers in future rates to defer credits that would otherwise be reflected as income, or, in the case of costs of removal, are created to match long-term future obligations arising from the current use of assets. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC or the Kentucky Commission. See Note 2, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Cash and Cash Equivalents. LG&E considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash. A deposit in the amount of $22 million, used as collateral for an $83 million interest rate swap expiring in 2020, is classified as restricted cash on LG&E's balance sheet. Advanced deposits of $2 million relating to projects are also restricted for equipment purchases.

Allowance for Doubtful Accounts. The allowance for doubtful accounts is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter.

Materials and Supplies. Fuel, natural gas stored underground and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies and are not currently traded by LG&E. At December 31, 2008 and 2007, the emission allowances inventory was less than $1 million.

Other Property and Investments. Other property and investments, included in other assets on the balance sheets, consists of LG&E's investment in OVEC and non-utility plant. LG&E and 11 other electric utilities are participating owners of OVEC, located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana. Pursuant to current contractual agreements, LG&E's share of OVEC's output is 5.63%, approximately 124 Mw of generation capacity.

As of December 31, 2008 and 2007, LG&E's investment in OVEC totaled less than $1 million. LG&E is not the primary beneficiary of OVEC; therefore, it is not consolidated into the Company's financial statements and is accounted for under the cost method of accounting. The direct exposure to loss as a result of its involvement with OVEC is generally limited to the value of its investment. In the event of the inability of OVEC to fulfill its power provision requirements, LG&E anticipates substituting such power supply with either owned generation or market purchases and believes it would generally recover associated incremental costs through regulatory rate mechanisms. See Note 9, Commitments and Contingencies, for further discussion of developments regarding LG&E's ownership interest and power purchase rights.

Utility Plant. Utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. LG&E has not recorded any allowance for funds used during construction, in accordance with Kentucky Commission regulations.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided were approximately 3.1% in 2008 (2.9% electric, 2.7% gas and 7.3% common); and 3.2% in 2007 (3.0% electric, 2.8% gas and 7.7% common) of average depreciable plant. Of the amount provided for depreciation, at December 31, 2008, approximately 0.4% electric, 0.9% gas and 0.1% common were related to the retirement, removal and disposal costs of long lived assets. Of the amount provided for depreciation, at December 31, 2007, approximately 0.4% electric, 0.8% gas and 0.1% common were related to the retirement, removal and disposal costs of long lived assets.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized using the straight-line method, which approximates the effective interest method, over the lives of the related bond issues.

Income Taxes. Income taxes are accounted for under SFAS No. 109, *Accounting for Income Taxes* and FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109*. In accordance with these statements, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are transactions for which the ultimate tax outcome is uncertain. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Uncertain tax positions are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 6, Income Taxes.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. LG&E and KU received an investment tax credit related to TC2. See Note 6, Income Taxes. Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of LG&E's tax liability based on credits for construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. LG&E accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable were $73 million and $65 million at December 31, 2008 and 2007, respectively.

Fuel and Gas Costs. The cost of fuel for electric generation is charged to expense as used, and the cost of natural gas supply is charged to expense as delivered to the distribution system. LG&E operates under a Kentucky Commission-approved performance-based ratemaking mechanism related to natural gas procurement activity. See Note 2, Rates and Regulatory Matters.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environmental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Recent Accounting Pronouncements. The following are recent accounting pronouncements affecting LG&E:

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The adoption of SFAS No. 161 will have no impact on LG&E's statements of operations, financial position and cash flows, however, additional disclosures relating to derivatives will be required beginning in the first quarter of 2009.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 was adopted effective January 1, 2008 and the Company elected not to fair value its eligible financial assets and liabilities.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments related to SFAS No. 157 have been evaluated and have no impact on the Company's financial statements. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives and cash collateral on derivatives, as required, are now provided. Per FASB Staff Position 157-2, fair value accounting for all nonrecurring fair value measurements of nonfinancial assets and liabilities will be adopted effective January 1, 2009.

Note 2 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the Kentucky Commission and the FERC in virtually all matters related to electric and gas utility regulation, and as such, its accounting is subject to SFAS No. 71. Given its position in the marketplace and the status of regulation in Kentucky, there are no plans or intentions to discontinue the application of SFAS No. 71.

Electric and Gas Rate Cases

In July 2008, LG&E filed an application with the Kentucky Commission requesting increases in base electric and gas rates. In conjunction with the filing of the application for changes in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008. In January 2009, LG&E, the AG, KIUC and all other parties to the rate cases filed a settlement agreement with the Kentucky Commission, under which LG&E's base gas rates will increase by $22 million annually, and base electric rates will decrease by $13 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated.

The VDT surcredit originated in December 2001, when the Kentucky Commission issued an Order approving a settlement agreement allowing LG&E to set up a regulatory asset of $141 million for workforce reduction costs and begin amortizing it over a five-year period starting in April 2001. The Order also provided for a surcredit to be included on customers' bills representing 40% of the annual savings derived from this initiative. For periods beginning January 1, 2006, the VDT surcredit had increased to $9 million per year.

In February 2006, LG&E and all parties to the proceeding reached a unanimous settlement agreement on the future ratemaking treatment of the VDT surcredit. Under the terms of the settlement agreement, the VDT surcredit continued at its current level until such time as LG&E filed for a change in electric or natural gas base rates. The Kentucky Commission issued an Order in March 2006, approving the settlement agreement. In accordance with the Order, the VDT surcredit terminated in August 2008, the first billing month after the July 2008 filing for a change in base rates.

The merger surcredit originated as part of the LG&E Energy merger with KU Energy Corporation in 1998. It was based on estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings were deferred and amortized over a five-year period pursuant to regulatory orders. In approving the merger, the Kentucky Commission adopted LG&E's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. These savings were provided in the form of a surcredit mechanism on customers' bills. In October 2003, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case in which the merger surcredit of $18 million per year would remain in place for another five-year term beginning July 1, 2003, and LG&E would file a plan for the merger surcredit six months before its expiration.

In December 2007, LG&E submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. In June 2008, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case which provided for a reduction in the merger surcredit to approximately $6 million for a 7-month period beginning July 2008, termination of the merger surcredit when new base rates went into effect on or after January 31, 2009, and that the annual merger surcredit be continued at an annual rate of $12 million thereafter should the Company not file for a change in base rates. In accordance with the Order, the merger surcredit was terminated effective February 6, 2009, with the implementation of new base rates.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the balance sheets as of December 31:

(in millions)	2008	2007
ARO	$ 29	$ 24
GSC	28	16
MISO exit	12	13
Unamortized loss on bonds	24	19
FAC	7	9
ECR	4	4
Hurricane Ike	24	-
Other	4	9
Subtotal	132	94
Pension and postretirement benefits	250	110
Total regulatory assets	$ 382	$ 204
Accumulated cost of removal of utility plant	$ 251	$ 241
Deferred income taxes – net	45	50
GSC ($29 million and $10 million at December 31, 2008 and 2007, respectively) and other	46	19
Total regulatory liabilities	$ 342	$ 310

LG&E does not currently earn a rate of return on the GSC, FAC and gas performance-based ratemaking regulatory assets (included in "Other" above), all of which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. LG&E will recover this asset through pension expense included in the calculation of base rates. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. Approval for the recovery of this asset was received from the Kentucky Commission as part of the 2008 base rate case. LG&E earns a rate of return on remaining regulatory assets, including other regulatory assets comprised of VDT costs (2007 only), merger surcredit, gas performance based ratemaking and Mill Creek Ash Pond costs. Other regulatory assets also include KCCS funding (see CMRG and KCCS Contributions below) and rate case expenses. LG&E will seek recovery of the KCCS funding in the next base rate case and received approval for the recovery of the rate case expenses as part of the 2008 base rate case. Other regulatory liabilities include DSM and MISO costs included in base rates that will be netted against costs of withdrawing from the MISO as part of the settlement agreement in the 2008 base rate case.

ARO. A summary of LG&E's net ARO assets, regulatory assets, ARO liabilities, regulatory liabilities and cost of removal established under FIN 47, *Accounting for Conditional Asset Retirement Obligations,* *an Interpretation of SFAS No. 143,* and SFAS No. 143, *Accounting for Asset Retirement Obligations* follows:

(in millions)	ARO Net Assets	ARO Liabilities	Regulatory Assets	Regulatory Liabilities	Accumulated Cost of Removal
As of December 31, 2006	$ 4	$ (28)	$ 22	$ -	$ 3
ARO accretion	-	(2)	2	-	-
Removal cost incurred	-	1	-	-	-
As of December 31, 2007	4	(29)	24	-	3
ARO accretion	-	(2)	2	-	-
Removal cost reclass	-	-	3	(3)	-
As of December 31, 2008	$ 4	$ (31)	$ 29	$ (3)	$ 3

Pursuant to regulatory treatment prescribed under SFAS No. 71, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million in 2008 and 2007 for the ARO accretion and depreciation expense. LG&E AROs are primarily related to the final retirement of assets associated with generating units and natural gas wells. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory liability pursuant to regulatory treatment prescribed under SFAS No. 71. There were no FIN 47 net asset additions during 2008 or 2007. For the year ended December 31, 2008, removal costs incurred were less than $1 million. For the years ended December 31, 2008 and 2007, LG&E recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under SFAS No. 71.

LG&E transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations are recorded for transmission and distribution assets.

GSC. LG&E's natural gas rates contain a GSC, whereby increases or decreases in the cost of natural gas supply are reflected in LG&E's rates, subject to approval by the Kentucky Commission. The GSC procedure prescribed by Order of the Kentucky Commission provides for quarterly rate adjustments to reflect the expected cost of natural gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of natural gas supply cost from prior quarters is to be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters.

LG&E's GSC was modified in 1997 to incorporate a natural gas procurement incentive mechanism. Since November 1, 1997, LG&E has operated under this PBR mechanism related to its natural gas procurement activities. LG&E's rates are adjusted annually to recover (or refund) its portion of the expense (or savings) incurred during each PBR year (12 months ending October 31). During the PBR year ending in 2008, LG&E achieved $11 million in savings. Of that total savings amount, LG&E's portion was approximately $3 million and the customers' portion was approximately $8 million. Pursuant to the extension of LG&E's natural gas supply cost PBR mechanism effective November 1, 2001, the sharing mechanism under the PBR requires savings (and expenses) to be shared 25% with shareholders and 75% with customers up to 4.5% of the benchmarked natural gas costs. Savings (and expenses) in excess of 4.5% of the benchmarked natural gas costs are shared 50% with shareholders and 50% with customers. The current natural gas supply cost PBR mechanism was extended through 2010 without further modification.

MISO. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, LG&E withdrew from the MISO effective September 1, 2006. Specific proceedings regarding the costs and benefits of the MISO and exit matters had been underway since July 2003. Since the exit from the MISO, LG&E has been operating under a FERC-approved open access-transmission tariff. LG&E now contracts with the Tennessee Valley Authority to act as its transmission Reliability Coordinator and Southwest Power Pool, Inc. to function as its Independent Transmission Organization, pursuant to FERC requirements.

LG&E and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $13 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. LG&E and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided LG&E with an immediate recovery of less than $1 million and an estimated $2 million over the next seven years for credits realized from other payments the MISO will receive, plus interest. In accordance with Kentucky Commission Orders approving the MISO exit, LG&E has established a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The approved base rate case settlement provided for MISO Schedule 10 expenses collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. LG&E and other parties have requested rehearing and a delay in any collection of RSG amounts. During January and February 2009, the FERC issued a deficiency letter in the proceeding relating to one prior Order, which delays collection of applicable RSG resettlements by the MISO pending further proceedings. Further developments in the RSG proceeding are expected to occur during 2009. Due to the numerous participants, complex principles at issue and changes from prior precedents, LG&E cannot predict the ultimate outcome of this matter. Based upon the recent FERC Orders, LG&E established a reserve during the fourth quarter of 2008, of $2 million relating to potential RSG resettlement costs for the period ended December 31, 2008.

Unamortized Loss on Bonds. The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight-line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

FAC. LG&E's retail electric rates contain an FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The FAC allows the Company to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges.

In January 2009, the Kentucky Commission initiated a routine examination of LG&E's FAC for the two-year period November 1, 2006 through October 31, 2008. A public hearing is scheduled in March 2009. An order is anticipated in the second quarter of 2009.

In August 2008, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period November 1, 2007 through April 30, 2008. The Kentucky Commission issued an Order in January 2009, approving the charges and credits billed through the FAC during the review period.

In January 2008, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in May 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of LG&E's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

In December 2006, the Kentucky Commission initiated its periodic two-year review of LG&E's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates for November 1, 2004 through October 31, 2006. In March 2007, the KIUC challenged LG&E's recovery of approximately $1 million in aggregate fuel costs LG&E incurred during a period prior to its exit from the MISO and requested the Kentucky Commission disallow this amount. A public hearing was held in May 2007. In October 2007, the Kentucky Commission issued its Order approving the calculation and application of LG&E's FAC charges and fuel procurement practices and indicated that LG&E was in compliance with the provisions of Administrative Regulation 807 KAR 5:5056. The Kentucky Commission further approved LG&E's recommendation for the transfer of fuel cost from the FAC to base rates. In November 2007, the KIUC filed a petition for rehearing, claiming the Kentucky Commission misinterpreted the KIUC's arguments in the proceeding. In the same month, the Kentucky Commission issued an Order denying the KIUC's request for rehearing. An appeal was not filed by the KIUC.

In January 2003, the Kentucky Commission reviewed KU's FAC and, as part of the Order in that case, required that an independent audit be conducted to examine operational and management aspects of both LG&E's and KU's fuel procurement functions. The final report's recommendations, issued in February 2004, related to documentation and process improvements. Management Audit Action Plans were agreed upon by LG&E and the Kentucky Commission Staff in the second quarter of 2004, and resulted in Audit Progress Reports being filed by LG&E with the Kentucky Commission. In February 2007, the Kentucky Commission staff indicated that LG&E fully complied with all audit recommendations and that no further reports are required.

ECR. Kentucky law permits LG&E to recover the costs of complying with the Federal Clean Air Act, including a return of operating expenses, and a return of and on capital invested, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the March 2009 expense month filing, which represents a slight increase over the current 10.50%.

In January 2009, the Kentucky Commission initiated a six-month review for the period ending October 31, 2008, of LG&E's environmental surcharge. An order is anticipated in the second quarter of 2009.

In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of LG&E's environmental surcharge. The Kentucky Commission issued an Order in August 2008, approving the charges and credits billed through the ECR during the review period and the rate of return on capital.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of LG&E's environmental surcharge. The Kentucky Commission issued a final Order in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Hurricane Ike. In September 2008, high winds from the remnants of Hurricane Ike passed through the service territory causing significant outages and system damage. In October 2008, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, approximately $24 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $24 million based on its actual costs for storm damages and service restoration due to Hurricane Ike.

Mill Creek Ash Pond Costs. In June 2005, the Kentucky Commission issued an Order approving the establishment of a regulatory asset for $6 million in costs related to the removal of ash from the Mill Creek ash pond, and authorized amortization over four years beginning in May 2006.

Rate Case Expenses. LG&E incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

CMRG and KCCS Contributions. In July 2008, LG&E and KU, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. LG&E and KU jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and LG&E will seek rate recovery in the Company's next base rate case.

Pension and Postretirement Benefits. LG&E adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* in 2006. This statement requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under SFAS No. 71, LG&E can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky is based on SFAS No. 87, *Employers' Accounting for Pensions,* and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions,* both of which were amended by SFAS No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery, therefore, the Company has recorded a regulatory asset representing the change in funded status of the pension and postretirement plans that is expected to be recovered. The regulatory asset will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Accumulated Cost of Removal of Utility Plant. As of December 31, 2008 and 2007, LG&E has segregated the cost of removal, previously embedded in accumulated depreciation, of $251 million and $241 million, respectively, in accordance with FERC Order No. 631. This cost of removal component is for assets that do not have a legal ARO under SFAS No. 143. For reporting purposes in the balance sheets, LG&E has presented this cost of removal as a regulatory liability pursuant to SFAS No. 71.

Deferred Income Taxes – Net. These regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

DSM. LG&E's rates contain a DSM provision. The provision includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows LG&E to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, LG&E and KU filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. LG&E and KU filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

<u>Other Regulatory Matters</u>

Storm Restoration. In January 2009, a significant winter ice storm passed through LG&E's service territory causing approximately 205,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 37,000 customer outages. LG&E currently estimates costs incurred of $34 million of expenses and $6 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

Regional Reliability Council. LG&E has changed its regional reliability council membership from the Reliability First Corporation to the SERC, effective January 1, 2007. Regional reliability councils are industry consortiums that promote, coordinate and ensure the reliability of the bulk electric supply systems in North America.

Arena. In August 2006, LG&E filed an application with the Kentucky Commission requesting approval for the sale of its Waterside property to the Louisville Arena Authority. The Kentucky Commission issued an Order in September 2006, approving the proposed transaction. In November 2006, LG&E completed certain agreements pursuant to its August 2006 Memorandum of Understanding with the Louisville Arena Authority regarding the proposed construction of an arena in downtown Louisville. LG&E entered into a relocation agreement with the Louisville Arena Authority providing for the reimbursement to LG&E of the costs to be incurred in relocating certain LG&E facilities related to the arena transaction. These costs are currently estimated to be approximately $63 million. As of December 31, 2008, approximately $58 million of the estimated total costs have been received. The relocation work is expected to be completed during 2009. The parties further entered into a property sale contract providing for LG&E's sale of a downtown site to the Louisville Arena Authority which was completed for $9 million in September 2008. The contract amounts are subject to potential adjustments for certain cost or expense variances related to potential future demolition, construction or site environmental developments, although the Company does not currently anticipate such events.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by LG&E and KU, together with the IMEA and the IMPA, was approved by the Kentucky Commission in November 2005.

CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

The CCN for the remaining line has been challenged by certain Hardin County, Kentucky property owners. In August 2006, LG&E and KU obtained a successful dismissal of the challenge at the Franklin County circuit court, which ruling was reversed by the Kentucky Court of Appeals in December 2007, and the proceeding reinstated. The matter is currently before the Kentucky Supreme Court on a motion for discretionary review filed by LG&E and KU in May 2008. The motion, which seeks reversal of the appellate court decision and reinstatement of the circuit court dismissal of the challenge has not yet been ruled upon.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures and certain Hardin County landowners have raised challenges to such transmission line in some of these forums as well. During 2008, LG&E and KU obtained various successful rulings at the Hardin County circuit court establishing their condemnation and easement rights. In August 2008, the landowners appealed such rulings to the Kentucky Court of Appeals and received a stay preventing LG&E and KU access to the properties during the appeal. LG&E and KU have petitioned the appellate court to lift the stay and otherwise sustain the lower court ruling, but such matter has not yet been ruled upon. In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky, claiming that certain National Historic Preservation Act requirements were not fully complied with by the U.S. Army relating to easements for the line through Fort Knox. LG&E and KU are cooperating with the U.S. Army in its defense in this case.

LG&E and KU continue to actively engage in settlement negotiations with the Hardin County property owners involved in the appeals of the condemnation proceedings. During the fourth quarter of 2008, LG&E and KU entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they had brought challenging the same transmission line. LG&E and KU are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to these transmission line approval and land acquisition proceedings.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in LG&E's market-based rate proceeding accepting LG&E's further proposal to address certain market power issues the FERC had claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of control areas in which it may be deemed to have market power, subject to a restriction that such power not be collusively re-sold back into such control areas. However, restrictions exist on sales by LG&E of power at market-based rates in the LG&E/KU and Big Rivers Electric Corporation control areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for LG&E's power sales at control area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. The Order is subject to a FERC rehearing process during which time the FERC has delayed implementation of the provisions relating to sales at interfaces. The Company cannot determine its ultimate impact at this time. As a condition of receiving and retaining market-based rate authority, LG&E must comply with applicable affiliate restrictions set forth in the FERC's regulation. During September 2008, LG&E submitted a regular tri-annual update filing under market-based rate regulations and FERC review proceedings for such filing remain in progress.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. LG&E is a member of the SERC, which acts as LG&E's RRO. During May 2008, the SERC and LG&E agreed to a settlement involving penalties totaling less than $1 million related to LG&E's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. The SERC and LG&E are currently involved in settlement negotiations concerning a June 2008 self-report by LG&E relating to three other standards and an October 2008 self-report of a possible violation relating to an additional standard. SERC proceedings for these June and October self-reports are in the early stages and therefore the outcome is unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. In December 2008, the SERC commenced a routine, periodic audit of LG&E and KU relating to certain designated reliability standards. This audit was completed during the first quarter of 2009 with no violations identified. While LG&E believes itself to be in compliance with the mandatory reliability standards, the Company cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

IRP. Integrated resource planning regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, LG&E and KU filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The AG and the KIUC were granted intervention in the IRP proceeding. During September 2008, LG&E and KU responded to public comments and they are awaiting the Kentucky Commission staff report which will close this proceeding. LG&E and KU are not able to predict further proceedings at this time.

PUHCA 2005. E.ON, LG&E's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including LG&E, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. LG&E believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005. The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005 and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252, Smart Metering standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254, Interconnection standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. Data discovery concluded in July 2007, and no parties to the case requested a hearing. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by LG&E for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008. LG&E will file annual reports on the program within 90 days of each plan year-end for the 3-year pilot period.

As part of the LG&E 2004 rate case settlement agreements, and as referred to in the Kentucky Commission EPAct 2005 Administrative Order, LG&E made its responsive pricing and smart metering pilot program filing, which addresses real-time pricing for residential and general service customers, in March 2007. The AG and KIUC were granted full intervention. In July 2007, the Kentucky Commission approved the application as filed, for 100 residential customers and a sampling of other customers, and authorized LG&E to establish the responsive pricing and smart metering pilot program, recovery of non-specific customer costs through the DSM billing mechanism and the filing of annual reports by April 1, 2009, 2010 and 2011. LG&E must also file an evaluation of the program by July 1, 2011.

Hydro Upgrade. In October 2005, LG&E received from the FERC a new license to upgrade, operate and maintain the Ohio Falls Hydroelectric Project. The license is for a period of 40 years, effective November 2005. LG&E began refurbishing the facility to add approximately 20 Mw of generating capacity in 2004, and plans to spend approximately $35 million from 2009 to 2011.

Gas Storage Field Matter. In March 2007, LG&E commenced a review of certain federal and state permitting, licensing and oversight matters relating to existing natural gas operations at its Doe Run, Kentucky storage field, which extends into Indiana. Following this review, LG&E submitted an application for Federal Power Act authorization in April 2007. The FERC accepted this application in July 2007, and granted appropriate permit status for retail gas activities and placed these activities in compliance for future periods. In August 2007, the FERC advised LG&E that it had concluded its investigation related to prior periods and had closed the matter with no further actions.

Green Energy Riders. In February 2007, LG&E and KU filed a Joint Application and Testimony for Proposed Green Energy Riders. The AG and KIUC were granted full intervention. In May 2007, a Kentucky Commission Order was issued authorizing LG&E to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits.

Home Energy Assistance Program. In July 2007, LG&E filed an application with the Kentucky Commission for the establishment of a new Home Energy Assistance program. During September 2007, the Kentucky Commission approved the new five-year program as filed, effective in October 2007. The program terminates in September 2012, and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge.

Collection Cycle Revision. In September 2007, LG&E filed an application with the Kentucky Commission to revise the collection cycle for customer bill payments from 15 days to 10 days to more closely align with the KU billing cycle and to avoid confusion for delinquent customers. In April 2008, the Kentucky Commission issued an Order denying LG&E's request to revise its collection cycle without prejudice for refiling the request in a base rate proceeding. As part of the base rate case filed on July 29, 2008, LG&E again proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreement approved in the rate case in February 2009, changed the due date for customer bill payments to 12 days after bill issuance for both LG&E and KU.

Depreciation Study. In December 2007, LG&E filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission. In July 2008, LG&E filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The settlement agreement in the rate case established new depreciation rates effective February 2009.

Brownfield Development Rider Tariff. In March 2008, LG&E received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. LG&E does not expect any impact as a result of this Order. LG&E shall file revised net metering tariffs and application forms within ninety days of the Order to comply with the new guidelines.

EISA 2007 Standards. In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and nonregulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008 and to complete the consideration by December 19, 2009.

Note 3 - Financial Instruments

The cost and estimated fair values of LG&E's non-trading financial instruments as of December 31 follow:

	2008		2007	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $120 million)	$ 411	$ 392	$ 574	$ 571
Long-term debt from affiliate	$ 485	$ 458	$ 410	$ 438
Interest-rate swaps - liability	$ 55	$ 55	$ 21	$ 21

The long-term debt valuations reflect prices quoted by dealers. The fair value of the long-term debt from affiliate is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates. The current market rates are determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in LG&E's credit ratings and default risk. The fair values of the swaps reflect price quotes from dealers, consistent with SFAS No. 157. The fair values of cash and cash equivalents, accounts receivable, accounts payable and notes payable are substantially the same as their carrying values.

LG&E is subject to the risk of fluctuating interest rates in the normal course of business. LG&E's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2008, a 100 basis point change in the benchmark rate on LG&E's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $4 million annually.

Interest Rate Swaps. LG&E uses over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature.

The fair value of the interest rate swaps is determined by a quote from the counterparty. This value is verified monthly by LG&E using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. Market liquidity is considered, however the valuation does not require an adjustment for market liquidity as the market is very active for swaps such as the Company utilizes. LG&E considered the impact of counterparty credit risk by evaluating credit ratings and financial information. All counterparties had strong investment grade ratings at December 31, 2008. LG&E did not have any credit exposure to the swap counterparties, as LG&E was in a liability position at December 31, 2008, therefore, the market valuation required no adjustment for counterparty credit risk. In addition, LG&E and the counterparties have agreed to post margin if the credit exposure exceeds certain thresholds. Using these valuation methodologies, the swap contracts are considered level 2 based on SFAS No. 157 measurement criteria. Cash collateral for interest rate swaps is classified as restricted cash and is a level 1 measurement based on the funds being held in a demand deposit account.

LG&E was party to various interest rate swap agreements with aggregate notional amounts of $179 million and $211 million as of December 31, 2008 and 2007, respectively. Under these swap agreements, LG&E paid fixed rates averaging 4.52% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 1.27% and 3.50% at December 31, 2008 and 2007, respectively. One swap hedging LG&E's $83 million Trimble County 2000 Series A bond has been designated as a cash flow hedge and continues to be highly effective. The remaining interest rate swaps designated to hedge LG&E's $128 million Jefferson County 2003 Series A bond became ineffective during 2008 as a result of the impact of downgrades of the underlying debt associated with issues involving the bond insurers. One swap with a notional value of $32 million was terminated in December 2008. See Note 7, Long-Term Debt.

The interest rate swaps are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended. Financial instruments designated as effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity. See Note 13, Accumulated Other Comprehensive Income. The ineffective portion of financial instruments designated as cash flow hedges is recorded to earnings monthly as is the entire change in the market value of the ineffective swaps. LG&E recorded a pre-tax loss of $8 million in other expense (income) during 2008, to reflect the ineffective portion of the interest rate swaps deemed highly effective. LG&E recorded a $36 million mark-to-market loss in earnings on the interest rate swaps related to the Jefferson County 2003 Series A bond after the swaps were deemed ineffective. Amounts recorded in accumulated other comprehensive income will be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million. A deposit in the amount of $22 million, used as collateral for one of the interest rate swaps, is classified as restricted cash on the balance sheet. The amount of the deposit required is tied to the market value of the swap.

A decline of 100 basis points in the current market interest rates would reduce the fair value of LG&E's interest rate swaps by approximately $35 million. Such a change could affect other comprehensive income if the hedge is effective, or the income statement if the hedge is ineffective.

Energy Trading and Risk Management Activities. LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with SFAS No. 133, as amended.

Energy trading and risk management contracts are valued using prices based on active trades on the

Intercontinental Exchange ("ICE"). In the absence of a traded price, midpoints of the best bids and offers will be the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs can include prices quoted by brokers or observable inputs other than quoted prices such as one-sided bids or offers as of the balance sheet date. Using these valuation methodologies, these contracts are considered level 2 based on SFAS No. 157 measurement criteria. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2008 and 2007, had a maturity of less than one year and were considered to be in a liquid market.

LG&E maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2008, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. LG&E has reserved against counterparty credit risk based on the counterparty's credit rating and applying historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2008 and 2007, counterparty credit reserves were less than $1 million.

LG&E manages the price volatility of its forecasted electric wholesale sales with the sales of market-traded electric forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income. Unrealized gains and losses are included in other expense – net, whereas realized gains and losses are included in electric revenues. Unrealized losses were $1 million and unrealized gains were less than $1 million in 2008 and 2007, respectively. Realized gains were $3 million and losses were $5 million in 2008 and 2007, respectively.

Effective January 1, 2008, LG&E adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157.

The following table sets forth by level within the fair value hierarchy LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. Cash collateral related to the energy trading and risk management contracts totals less than $1 million, is categorized as restricted cash and is a level 1 measurement based on the funds being held in liquid accounts. There are no level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1	Level 2	Total
Financial Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Interest rate swap cash collateral	22	-	22
Total Financial Assets	$ 22	$ 1	$ 23
Financial Liabilities:			
Interest rate swaps	$ -	$ 55	$ 55
Total Financial Liabilities	$ -	$ 55	$ 55

Note 4 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

LG&E's customer receivables and natural gas and electric revenues arise from deliveries of natural gas to approximately 314,000 customers and electricity to approximately 389,000 customers in Louisville and adjacent areas in Kentucky. For the year ended December 31, 2008, 69% of total revenue was derived from electric operations and 31% from natural gas operations. For the year ended December 31, 2007, 73% of total revenue was derived from electric operations and 27% from natural gas operations. During 2008, LG&E's 10 largest electric and gas customers accounted for less than 10% and less than 15% of total volumes, respectively.

Effective November 2008, LG&E and employees represented by the IBEW Local 2100 signed a three-year collective bargaining agreement. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions. The employees represented by this bargaining agreement comprise approximately 68% of LG&E's workforce at December 31, 2008.

Note 5 - Pension and Other Postretirement Benefit Plans

LG&E employees benefit from both funded and unfunded non-contributory defined benefit pension plans and other postretirement benefit plans that together cover employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The Company makes an annual lump sum contribution to the RIA, based on years of service and a percentage of covered compensation. The health care plans are contributory with participants' contributions adjusted annually. LG&E uses December 31 as the measurement date for its plans.

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2008, and a statement of the funded status as of December 31 for LG&E's sponsored defined benefit plans:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Change in benefit obligation				
Benefit obligation at beginning of year	$ 408	$ 408	$ 89	$ 105
Service cost	4	4	1	1
Interest cost	26	24	5	5
Plan amendments	-	19	2	2
Benefits paid, net of retiree contributions	(28)	(28)	(9)	(9)
Actuarial (gain)/loss and other	19	(19)	-	(15)
Benefit obligation at end of year	$ 429	$ 408	$ 88	$ 89
Change in plan assets				
Fair value of plan assets at beginning of year	$ 409	$ 356	$ 5	$ 6
Actual return on plan assets	(94)	26	-	1
Employer contributions	-	56	7	7
Benefits paid, net of retiree contributions	(28)	(28)	(9)	(9)
Administrative expenses and other	(1)	(1)	-	-
Fair value of plan assets at end of year	$ 286	$ 409	$ 3	$ 5
Funded status at end of year	$ (143)	$ 1	$ (85)	$ (84)

Amounts Recognized in Statement of Financial Position. The following tables provide the amounts recognized in the balance sheets and information for plans with benefit obligations in excess of plan assets as of December 31:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Regulatory assets	$ 233	$ 93	$ 17	$ 17
Non-current assets	-	14	-	-
Accrued benefit liability (current)	-	-	(3)	(3)
Accrued benefit liability (non-current)	(143)	(13)	(82)	(81)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Benefit obligation	$ 429	$ 408	$ 88	$ 89
Accumulated benefit obligation	396	378	-	-
Fair value of plan assets	286	409	3	5

For discussion of the pension and postretirement regulatory assets, see Note 2, Rates and Regulatory Matters.

Components of Net Periodic Benefit Cost. The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both LG&E employees and E.ON U.S. Services' employees, who are providing services to the utility. The E.ON U.S. Services' costs that are allocated to LG&E are approximately 42% of E.ON U.S. Services' total cost for both 2008 and 2007.

(in millions)	Pension Benefits					
	LG&E 2008	Servco Allocation to LG&E 2008	Total LG&E 2008	LG&E 2007	Servco Allocation to LG&E 2007	Total LG&E 2007
Service cost	$ 4	$ 4	$ 8	$ 4	$ 4	$ 8
Interest cost	26	5	31	24	5	29
Expected return on plan assets	(32)	(5)	(37)	(32)	(5)	(37)
Amortization of prior service costs	6	1	7	5	1	6
Amortization of actuarial loss	1	-	1	2	1	3
Benefit cost at end of year	$ 5	$ 5	$ 10	$ 3	$ 6	$ 9

	Other Postretirement Benefits					
	LG&E 2008	Servco Allocation to LG&E 2008	Total LG&E 2008	LG&E 2007	Servco Allocation to LG&E 2007	Total LG&E 2007
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Amortization of prior service costs	2	-	2	2	-	2
Benefit cost at end of year	$ 8	$ 1	$ 9	$ 8	$ 1	$ 9

The assumptions used in the measurement of LG&E's pension benefit obligation are shown in the following table:

	2008	2007
Weighted-average assumptions as of December 31:		
Discount rate - Union plan	6.33%	6.56%
Discount rate - Non-union plan	6.25%	6.66%
Rate of compensation increase	5.25%	5.25%

The discount rates were determined by the December 29, 2008, Mercer Pension Discount Yield Curve. These discount rates were then lowered by 2 basis points for the average change in 4 bond indices, Citigroup High Grade Credit Index AAA/AA 10+ years, Lehman Brothers US AA Long Credit, Merrill Lynch US Corporate AA-AAA rated 10+ years and Merrill Lynch US Corporate AA rated 15+ years, for the period from December 29, 2008 to December 31, 2008.

The assumptions used in the measurement of LG&E's net periodic benefit cost are shown in the following table:

	2008	2007
Discount rate	6.66%	5.96%
Expected long-term return on plan assets	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, LG&E considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate could have an approximate $47 million positive or negative impact to the 2008 accumulated benefit obligation and an approximate $54 million positive or negative impact to the 2008 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have an approximate $1 million positive or negative impact on 2008 pension expense.

Assumed Health care Cost Trend Rates. For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for 2008. The rate was assumed to decrease gradually to 5% by 2016 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million on the 2008 total of service and interest costs components and an increase or decrease of $2 million in year-end 2008 postretirement benefit obligations.

Expected Future Benefit Payments. The following list provides the amount of expected future benefit payments, which reflect expected future service:

(in millions)	Pension Benefits	Other Postretirement Benefits
2009	$ 27	$ 7
2010	26	7
2011	26	8
2012	26	8
2013	25	8
2014-18	133	37

Plan Assets. The following table shows LG&E's weighted-average asset allocation by asset category at December 31:

Pension Plans	Target Range	2008	2007
Equity securities	45% - 75%	55%	57%
Debt securities	30% - 50%	43	43
Other	0% - 10%	2	-
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Lehman Aggregate and Lehman U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that either are of short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

Contributions. LG&E made a discretionary contribution to the pension plan of $56 million in January 2007. In addition, contributions to other postretirement benefit plans of $7 million were made in 2008 and 2007. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. In 2009, LG&E anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company has monitored developments regarding the Act and has made a number of elections to comply.

Thrift Savings Plans. LG&E has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. LG&E makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were $3 million and $2 million for 2008 and 2007, respectively.

LG&E also makes contributions to retirement income accounts within its thrift savings plans for certain employees not covered by its noncontributory defined benefit pension plans. These employees consist mainly of those hired after December 31, 2005. LG&E makes these contributions based on years of service and the employees' wage and salary levels, and it makes them in addition to the matching contributions discussed above. The amounts contributed by LG&E under this arrangement equaled less than $1 million in 2008 and in 2007.

Note 6 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, E.ON US Investments Corp., for each tax period. Each subsidiary of the consolidated tax group, including LG&E, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. LG&E also files income tax returns in various state jurisdictions. While the federal statute of limitations related to 2005 and later years are open, Revenue Agent Reports for 2005-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments made by the IRS for the 2005-2006 tax years were recorded in the 2008 financial statements. The tax year 2007 return was examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed. Preliminary adjustments for 2007 were agreed to in January 2009, and were comprised of $5 million of depreciable temporary differences which will be recorded in 2009. The tax year 2008 return is also being examined under the CAP program.

LG&E adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, LG&E had $1 million of unrecognized tax benefits related to federal and state income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Additions and reductions of uncertain tax positions during 2008 and 2007 were less than $1 million. Possible amounts of uncertain tax positions for LG&E that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes.

Interest and penalties, if any, are recorded as operating expenses on the income statement and accrued expenses on the balance sheet. The amount LG&E recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of December 31, 2008 and 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, LG&E accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by LG&E upon adoption of FIN 48, or through December 31, 2008.

Components of income tax expense are shown in the table below:

(in millions)		2008	2007
Current	- federal	$ 37	$ 34
	- state	4	8
Deferred	- federal – net	(2)	10
	- state – net	(2)	2
Investment tax credit – deferred		8	9
Amortization of investment tax credit		(4)	(4)
Total income tax expense		$ 41	$ 59

Current state tax expense decreased due to an increase in coal and recycle credits in 2008. Deferred federal income tax expense decreased at December 31, 2008 compared to December 31, 2007 due to temporary differences for mark-to-market interest rate swaps and GSC.

In June 2006, LG&E and KU filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that LG&E and KU were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credit. LG&E's portion of the TC2 tax credit will be approximately $25 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, LG&E recorded investment tax credits of $8 million and $9 million in 2008 and 2007, respectively, decreasing current federal income taxes. In addition, a full depreciation basis adjustment is required for the amount of the credit. The income tax expense impact of this adjustment will begin when the facility is placed in service.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. In August 2008, the plaintiffs submitted an amended complaint alleging additional claims for relief. In November 2008, the Court dismissed the suit; however, the plaintiffs filed a motion for reconsideration. The Company is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

Components of net deferred tax liabilities included in the balance sheets are shown below:

(in millions)	2008	2007
Deferred tax liabilities:		
Depreciation and other plant-related items	$ 372	$ 368
Regulatory assets and other	39	30
Pension and related benefits	4	5
Total deferred tax liabilities	415	403
Deferred tax assets:		
Investment tax credit	12	14
Income taxes due to customers	18	19
Liabilities and other	39	24
Total deferred tax assets	69	57
Net deferred income tax liability	$ 346	$ 346
Balance sheet classification		
Current liabilities	$ 4	$ 4
Non-current liabilities	342	342
Net deferred income tax liability	$ 346	$ 346

LG&E expects to have adequate levels of taxable income to realize its recorded deferred tax assets.

A reconciliation of differences between the statutory U.S. federal income tax rate and LG&E's effective income tax rate follows:

	2008	2007
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	0.6	3.4
Reduction of income tax reserve	(0.4)	(0.6)
Qualified production activities deduction	(1.0)	(1.1)
Amortization of investment tax credits	(3.0)	(2.2)
Other differences	0.1	(1.5)
Effective income tax rate	31.3 %	33.0 %

State income tax, net of federal benefit decreased due to coal and recycle credits claimed in 2008. Amortization of investment tax credits increased in 2008 due to the level of pre-tax income. Other differences primarily relate to various permanent differences and deferred adjustments.

Note 7 - Long-Term Debt

As of December 31, 2008 and 2007, long-term debt and the current portion of long-term debt consist primarily of pollution control bonds and long-term loans from affiliated companies as summarized below.

($ in millions)	Stated Interest Rates	Maturities	Principal Amounts
Outstanding at December 31, 2008:			
Noncurrent portion	Variable – 6.48%	2012-2037	$ 776
Current portion	Variable	2026-2027	$ 120
Outstanding at December 31, 2007:			
Noncurrent portion	Variable – 5.98%	2012-2037	$ 864
Current portion	Variable	2026-2027	$ 120

Long-term debt includes $120 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Jefferson County Series 2001 A and B and Trimble County Series 2001 A and B. Maturity dates for these bonds range from 2026 to 2027. The average annualized interest rate for these bonds during 2008 and 2007 was 2.34% and 3.66%, respectively.

Pollution control series bonds are obligations of LG&E issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during April 2007, the county's debt was also secured by an equal amount of LG&E's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless the Company defaults on the loan agreement. Subsequent to April 2007, the loan agreement is an unsecured obligation of LG&E.

Several of the pollution control bonds are or were insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At December 31, 2008, LG&E had an aggregate $574 million (including $163 million of reacquired bonds) of outstanding pollution control indebtedness, of which $135 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" where there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture which can be as high as 15%. During 2008 and 2007, the average rate on the auction rate bonds was 5.90% and 3.77%, respectively. The instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In 2008, the ratings of the following bonds were downgraded due to downgrades of the bond insurers or the termination of the bond insurance.

($ in millions)		Bond Rating			
		Moody's		S&P	
Tax Exempt Bond Issues	Principal	2008	2007	2008	2007
Jefferson Co. 2000 Series A (1)	$ 25	A2	Aaa	BBB+	AAA
Trimble County 2000 Series A	$ 83	A2	Aaa	A	AAA
Jefferson Co. 2001 Series A	$ 10	A2	Aaa	A	AAA
Trimble County 2002 Series A	$ 42	A2	Aaa	A	AAA
Louisville Metro 2003 Series A	$ 128	A2	Aaa	BBB+	AAA
Louisville Metro 2005 Series A (1)	$ 40	A2	Aaa	BBB+	AAA
Trimble County 2007 Series A	$ 60	A2	Aaa	A	AAA
Louisville Metro 2007 Series A (1)	$ 31	A2	Aaa	BBB+	AAA
Louisville Metro 2007 Series B	$ 35	A2	Aaa	A	AAA

(1) Bond insurance terminated in November 2008 upon restructuring.

In February 2008, LG&E issued a notice to bondholders of its intention to convert the Louisville Metro 2005 Series A and, 2007 Series A and B bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. These conversions were completed in March 2008, for the 2005 Series, and in April 2008, for the two 2007 Series. In connection with the conversions, LG&E purchased the bonds from the remarketing agent. The Louisville Metro 2005 and 2007 Series A bonds were remarketed in November 2008.

In March 2008, LG&E issued notices to bondholders of its intention to convert the Jefferson County 2000 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in May 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent. The bonds were remarketed in November 2008.

In June 2008, LG&E issued notices to bondholders of its intention to convert the Louisville Metro 2003 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, LG&E purchased the bonds from the remarketing agent.

In November 2008, LG&E converted three pollution control bonds to a mode wherein the interest rate is fixed for an intermediate term, but not the full term of the bond. At the end of the intermediate term, the Company must remarket the bonds or buy them back. The terms of the November transactions are:

($ in millions) Series	Principal Amount	Interest Rate	End of Fixed Rate Term
Jefferson County 2000 Series A	$ 25	5.375%	November 30, 2011
Louisville Metro 2007 Series A	$ 31	5.625%	December 2, 2012
Louisville Metro 2005 Series A	$ 40	5.75%	December 1, 2013

At the time of the conversion, the bond insurance policy that had been in place was terminated.

As of December 31, 2008, LG&E continued to hold repurchased bonds in the amount of $163 million.

LG&E will hold some or all of such repurchased bonds until a later date, at which time LG&E may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps LG&E has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructuring or redemption and refinancing, could result in LG&E incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

All of LG&E's first mortgage bonds were released and terminated in April 2007. Only the tax-exempt pollution control revenue bonds issued by the counties remain. Under the provisions for certain of LG&E's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for these bonds during 2008 and 2007 was 2.34% and 3.66%, respectively.

Interest rate swaps are used to hedge LG&E's underlying variable-rate debt obligations. These swaps hedge specific debt issuances and, consistent with management's designation, are accorded hedge accounting treatment. The swaps exchange floating-rate interest payments for fixed rate interest payments to reduce the impact of interest rate changes on LG&E's pollution control bonds. As of December 31, 2008 and 2007, LG&E had swaps with an aggregate notional value of $179 million and $211 million, respectively. See Note 3, Financial Instruments.

Redemptions and maturities of long-term debt for 2008 and 2007 are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2007	Pollution control bonds	$ 31	Variable	Secured	2017
2007	Pollution control bonds	$ 60	Variable	Secured	2017
2007	Pollution control bonds	$ 35	Variable	Secured	2013
2007	Mandatorily Redeemable Preferred Stock	$ 20	5.875%	Unsecured	2008

Issuances of long-term debt for 2007 and 2008 are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Due to Fidelia	$ 50	6.48%	Unsecured	2015
2008	Due to Fidelia	$ 25	6.21%	Unsecured	2018
2007	Pollution control bonds	$ 31	Variable	Unsecured	2033
2007	Pollution control bonds	$ 60	4.60%	Unsecured	2033
2007	Pollution control bonds	$ 35	Variable	Unsecured	2033
2007	Due to Fidelia	$ 70	5.98%	Unsecured	2037
2007	Due to Fidelia	$ 68	5.93%	Unsecured	2031
2007	Due to Fidelia	$ 47	5.72%	Unsecured	2022

In January 2007, the Kentucky Commission issued an Order approving LG&E's application for certain financial transactions, including arrangements which provided a source of funds for the redemption of LG&E's preferred stock. In April 2007, LG&E redeemed all of its outstanding shares of its series of preferred stock at the following redemption prices, respectively, plus an amount equal to accrued and unpaid dividends to the redemption date:

- 860,287 shares of 5% cumulative preferred stock (par value $25 per share) at $28 per share;

- 200,000 shares of $5.875 cumulative preferred stock (without par value) at $100 per share; and
- 500,000 shares of auction rate, series A, cumulative preferred stock (without par value) at $100 per share.

In April 2007, LG&E agreed with Fidelia to eliminate the lien on two secured intercompany loans totaling $125 million. LG&E entered into two long-term borrowing arrangements with Fidelia in an aggregate principal amount of $138 million. The loan proceeds were used to fund the preferred stock redemption and to repay certain short-term loans incurred to fund the pension contribution made by the Company during the first quarter. LG&E also completed a series of financial transactions impacting its periodic reporting requirements. The pollution control revenue bonds issued by certain governmental entities secured by the $31 million Pollution Control Series S, the $60 million Pollution Control Series T and the $35 million Pollution Control Series U bonds were refinanced and replaced with new unsecured tax-exempt bonds of like amounts. Pursuant to the terms of the bonds, an underlying lien on substantially all of LG&E's assets was released following the completion of these steps. LG&E no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

Long-term debt maturities for LG&E are shown in the following table:

(in millions)	
2009 – 2011	$ -
2012	25
2013	200
Thereafter	671 (a)
Total	$ 896

(a) Includes long-term debt of $120 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2026 to 2027.

Note 8 - Notes Payable and Other Short-Term Obligations

LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2008	$ 400	$ 222	$ 178	1.49%
December 31, 2007	$ 400	$ 78	$ 322	4.75%

E.ON U.S. maintains revolving credit facilities totaling $313 million and $150 million at December 31, 2008 and 2007, respectively, to ensure funding availability for the money pool. At December 31, 2008, one facility, totaling $150 million, is with E.ON North America, Inc., while the remaining line, totaling

$163 million, is with Fidelia; both are affiliated companies. The facility as of December 31, 2007, was with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2008	$ 313	$ 299	$ 14	2.05%
December 31, 2007	$ 150	$ 62	$ 88	4.97%

During June 2007, LG&E's five existing lines of credit totaling $185 million expired and were replaced with short-term bilateral lines of credit facilities totaling $125 million. During the third quarter of 2007, LG&E extended the maturity date of these facilities through June 2012. There was no outstanding balance under any of these facilities at December 31, 2008.

The covenants under these revolving lines of credit include the following:

- The debt/total capitalization ratio must be less than 70%
- E.ON must own at least 66.667% of voting stock of LG&E directly or indirectly
- The corporate credit rating of the Company must be at or above BBB- and Baa3 as determined by S&P and Moody's
- A limitation on disposing of assets aggregating more than 15% of total assets as of December 31, 2006

LG&E was in compliance with these covenants at December 31, 2008.

Note 9 - Commitments and Contingencies

Operating Leases. LG&E leases office space, office equipment, plant equipment and vehicles and accounts for these leases as operating leases. Total lease expense less amounts contributed by affiliated companies occupying a portion of the office space leased by LG&E, was $6 million and $5 million for 2008 and 2007, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2008, are shown in the following table:

(in millions)	
2009	$ 9
2010	5
2011	4
2012	3
2013	4
Thereafter	5
Total	$ 30

Sale and Leaseback Transaction. LG&E is a participant in a sale and leaseback transaction involving its 38% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, LG&E and KU entered into a tax-efficient, 18-year lease of the CTs. LG&E and KU have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if LG&E had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

In case of default under the lease, LG&E is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to LG&E and KU.

At December 31, 2008, the maximum aggregate amount of default fees or amounts was $9 million, of which LG&E would be responsible for 38% (approximately $3 million). LG&E has made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay LG&E's full portion of any default fees or amounts.

Letters of Credit. LG&E has provided letters of credit totaling $3 million to support certain obligations related to landfill reclamation and a letter of credit totaling less than $1 million to support certain obligations related to workers' compensation.

Purchased Power. LG&E has a contract for purchased power with OVEC, terminating in 2026, for various Mw capacities. LG&E has an investment of 5.63% ownership in OVEC's common stock, which is accounted for on the cost method of accounting. LG&E's share of OVEC's output is 5.63%, approximately 124 Mw of generation capacity. Future obligations for power purchases are shown in the following table:

(in millions)	
2009	$ 20
2010	21
2011	21
2012	23
2013	23
Thereafter	349
Total	$ 457

Coal and Gas Purchase Obligations. LG&E has contracts to purchase coal, natural gas and natural gas transportation. Future obligations are shown in the following table:

(in millions)	
2009	$ 307
2010	309
2011	308
2012	123
2013	63
Thereafter	- (a)
Total	$ 1,110

(a) Obligations after 2013 are indexed to future market prices and will not be included above until prices are set using the contracted methodology.

Construction Program. LG&E had $39 million of commitments in connection with its construction program at December 31, 2008.

In June 2006, LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights. The parties have commenced certain negotiations relating to potential construction cost increases due to higher labor and per diem costs above an established baseline, and certain safety and compliance costs resulting from a change in law. LG&E's share of additional costs from inception of the contract through the expected project completion in 2010 may be approximately $5 million.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendency of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, LG&E administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an Order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ revised the permit to address the issues identified in the EPA's Order, although the Sierra Club subsequently submitted comments objecting to the revisions. Although the Company does not expect material changes in the permit as a result of the various petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Mine Safety Compliance Costs. In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky and other states that supply coal to LG&E, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of some of the coal contracts LG&E has in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. LG&E has begun to receive information from the mines it contracts with regarding price adjustments related to these compliance costs and has hired a consultant to review all supplier claims for validity and reasonableness. At this time LG&E has not been notified of claims by all mines and is reviewing those claims it has received. An adjustment will be made to the value of the coal inventory once the amount is determinable, however, the amount cannot be estimated at this time. The Company expects to recover these costs through the FAC.

Environmental Matters. LG&E's operations are subject to a number of environmental laws and regulations, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to LG&E's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation, but leaving the CAIR in the interim. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. LG&E is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and LG&E's and KU's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. In addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has announced that it intends to promulgate a new rule to replace the CAMR. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new mercury reduction rules with different or more stringent requirements. Kentucky has also repealed its corresponding state mercury regulations. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 through 2008 time period at a cost of $197 million. In

2001, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E for these projects under its periodic environmental surcharge mechanisms. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling $100 million during the 2009 through 2011 time period for pollution control equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by the Company for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. LG&E is monitoring on-going efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. LG&E is also monitoring on-going regulatory proceedings including the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. The new administration has announced its intention to exercise its existing authority under the Clean Air Act to achieve reductions in GHG emissions. LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of LG&E, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. LG&E and KU have complied with the information requests and are not able to predict further proceedings in this matter at this time.

General Environmental Proceedings. From time to time, LG&E appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation obligations or activities for former manufactured gas plant sites or elevated PCB levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; on-going claims regarding alleged particulate emissions from LG&E's Cane Run station and claims regarding GHG emissions from LG&E's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of LG&E.

Note 10 - Jointly Owned Electric Utility Plant

LG&E owns a 75% undivided interest in Trimble County Unit 1 which the Kentucky Commission has allowed to be reflected in customer rates. Of the remaining 25% of the unit, IMEA owns a 12.12% undivided interest, and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate ownership share of fuel cost, operation and maintenance expenses and incremental assets. The following data represent shares of the jointly owned property:

	Trimble County Unit 1			
	LG&E	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	383	66	62	511

(in millions)	
LG&E's 75% ownership:	
Cost	$ 606
Accumulated depreciation	251
Net book value	$ 355
Construction work in progress (included in above)	$ 12

LG&E and KU have begun construction of TC2, a jointly owned unit at the Trimble County site. LG&E and KU own undivided 14.25% and 60.75% interests, respectively, in TC2. Of the remaining 25% of TC2, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is expected to occur in 2010. In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	107	455	97	91	750

(in millions)			
LG&E's 14.25% ownership:		KU's 60.75% ownership:	
Cost	$ 136	Cost	$ 560
Accumulated depreciation	2	Accumulated depreciation	-
Net book value	$ 134	Net book value	$ 560

	LG&E	KU
Construction work in progress (included in above)	$132	$550

LG&E and KU jointly own the following CTs and related equipment:

($ in millions)	LG&E				KU				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
LG&E 53%, KU 47% (a)	146	62	(15)	47	129	53	(12)	41	275	115	(27)	88
LG&E 38%, KU 62% (b)	118	51	(8)	43	190	82	(14)	68	308	133	(22)	111
LG&E 29%, KU 71% (c)	92	32	(6)	26	228	80	(18)	62	320	112	(24)	88
LG&E 37%, KU 63% (d)	236	79	(12)	67	404	137	(21)	116	640	216	(33)	183
LG&E 29%, KU 71% (e)	n/a	3	(1)	2	n/a	9	(2)	7	n/a	12	(3)	9

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 10 Mw of capacity for LG&E.
(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both LG&E's and KU's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on its respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 - Segments of Business and Related Information

LG&E is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and the storage, distribution and sale of natural gas. LG&E is regulated by the Kentucky Commission and files electric and natural gas financial information separately with the Kentucky

Commission. The Kentucky Commission establishes rates specifically for the electric and natural gas businesses. Therefore, management reports analyze financial performance based on the electric and natural gas segments of the business. Financial data for business segments follow:

(in millions)	Electric	Gas	Total
2008			
Operating revenues	$ 1,015	$ 452	$ 1,467
Depreciation and amortization	107	20	127
Income taxes	36	5	41
Interest income	1	-	1
Interest expense	43	10	53
Net income	82	8	90
Total assets	2,827	810	3,637
Construction expenditures	195	50	245
2007			
Operating revenues	$ 933	$ 353	$ 1,286
Depreciation and amortization	107	19	126
Income taxes	54	5	59
Interest income	1	-	1
Interest expense	41	9	50
Net income	112	8	120
Total assets	2,669	644	3,313
Construction expenditures	164	39	203

Note 12 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as electric operating revenues and purchased power operating expense. LG&E intercompany electric revenues and purchased power expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Electric operating revenues from KU	$ 109	$ 93
Purchased power from KU	80	46

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

LG&E's intercompany interest income and expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Interest on money pool loans	$ 6	$ 4
Interest on Fidelia loans	23	17

Other Intercompany Billings

E.ON U.S. Services provides LG&E with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. Services on behalf of LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services is directly charged to LG&E, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of LG&E, primarily tax settlements, and other payments made by LG&E on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from LG&E for the years ended December 31, were as follows:

(in millions)	2008	2007
E.ON U.S. Services billings to LG&E	$ 206	$ 385
LG&E billings to KU	5	12
KU billings to LG&E	75	6
LG&E billings to E.ON U.S. Services	5	12

In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

In March 2008, LG&E paid a dividend of $40 million to its common shareholder, E.ON U.S.

LG&E received capital contributions of $20 million from its common shareholder, E.ON U.S., in both December 2008 and December 2007.

Note 13 – Accumulated Other Comprehensive Income

Accumulated other comprehensive income (loss) consisted of the following:

(in millions)	Accumulated Derivative Gain or Loss	Pre-Tax	Income Taxes	Net
Balance at December 31, 2006	$ (15)	$ (15)	$ 6	$ (9)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	(6)	(6)	2	(4)
Balance at December 31, 2007	$ (21)	$ (21)	$ 8	$ (13)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	(1)	(1)	-	(1)
Balance at December 31, 2008	$ (22)	$ (22)	$ 8	$ (14)

Note 14 - Subsequent Events

On January 13, 2009, LG&E, the AG, KIUC and all other parties to the rate cases filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, LG&E's base gas rates will increase $22 million annually, and base electric rates will decrease $13 million annually. An Order approving the settlement was received on February 5, 2009. The new rates were implemented effective February 6, 2009. However, in connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit, respectively, terminated, which will amount in increased revenues of approximately $21 million annually.

On January 27 and 28, 2009, a significant winter ice storm passed through LG&E's service territory causing approximately 205,000 customer outages, followed closely by a severe wind storm on February 11, 2009, causing approximately 37,000 customer outages. LG&E currently estimates costs incurred of $34 million of expenses and $6 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

TRANSFER OF ASSETS

In 2008, Louisville Gas and Electric Company (LG&E) transferred a cooling tower located at the Trimble County generation facility to Kentucky Utilities Company (KU) with a value of $10,137,562. Also in 2008, there were transfers of transmission equipment or facilities from KU to LG&E with a value of $277,078. There were no transfers of equipment or facilities between LG&E or KU and E.ON U.S. LLC.

INTERCOMPANY MONTHLY INVOICES

Monthly invoices are prepared for reimbursement of non-fuel related expenses incurred by LG&E or KU for LG&E, KU, E.ON U.S. Services Inc. (Servco), E.ON U.S. LLC (E.ON U.S.) and subsidiaries. The invoices are provided to Servco, E.ON U.S. and subsidiaries by the 10^{th} business day of the subsequent month with payment due by the 13^{th} business day of the month. The invoices and cash disbursement requests related to fuel and fuel-related products are prepared on the business day before the 15^{th} and 25^{th} for reimbursement on the 15^{th} and 25^{th} or the next business day. All billings between the regulated utilities (LG&E/KU) and non-regulated entities (Servco/E.ON U.S.) are billed and settled on a net basis.

In addition to the invoices, summary transaction listings are provided as supporting documentation of the expenses on each billing. A system-generated process from the Oracle General Ledger system provides the summary of the transactions that resulted in automatic intercompany transactions among companies. For fuel and fuel-related product transactions, a report from Fuelworx, the Fuels Management System, provides a summary of the transactions that resulted in automatic intercompany transactions between the companies. Monthly reconciliation and balancing procedures are currently in place for all entities receiving and providing intercompany charges to ensure the accuracy of such transactions.

KENTUCKY UTILITIES
INTERCOMPANY BILLING TO LG&E UTILITY
December 31, 2008

Charges to LG&E Utility

Invoice Date: **1/12/09**

Description			Amount
Vouchers		$	298,089.85
Labor		$	368.22
Burdens		$	(33,043.06)
Materials		$	(7,839.92)
	Subtotal	$	257,575.09
Miscellaneous J/Es		$	12,675,450.12
CT O&M Expenses		$	526,118.78
Adjustment to previous month Power Sales to LG&E		$	(1,627,730.36)
	Subtotal	$	11,573,838.54
	Total Due from LG&E Utility	$	11,831,413.63

Billing to LG&E Utility

ivoices USD 01-DEC-08	0110	146100	0100	254.56
ivoices USD 02-DEC-08	0110	146100	0100	18,000.85
ivoices USD 03-DEC-08	0110	146100	0100	9,214.49
ivoices USD 02-DEC-08	0110	146100	0100	(858.25)
ivoices USD 03-DEC-08	0110	146100	0100	132,412.57
ivoices USD 04-DEC-08	0110	146100	0100	27,961.40
ivoices USD 04-DEC-08	0110	146100	0100	(40,840.14)
JSD 05-DEC-08	0110	146100	0100	(480.60)
ivoices USD 05-DEC-08	0110	146100	0100	853.90
ivoices USD 05-DEC-08	0110	146100	0100	(443.26)
ivoices USD 06-DEC-08	0110	146100	0100	1,222.72
ivoices USD 08-DEC-08	0110	146100	0100	56,584.47
ivoices USD 08-DEC-08	0110	146100	0100	(130.36)
ivoices USD 09-DEC-08	0110	146100	0100	(1,520.04)
ivoices USD 10-DEC-08	0110	146100	0100	3,793.51
ivoices USD 10-DEC-08	0110	146100	0100	(5,196.84)
ivoices USD 11-DEC-08	0110	146100	0100	4,853.72
ivoices USD 11-DEC-08	0110	146100	0100	(40.00)
ivoices USD 12-DEC-08	0110	146100	0100	302,034.01
ivoices USD 12-DEC-08	0110	146100	0100	(739,092.69)
ivoices USD 13-DEC-08	0110	146100	0100	32,630.45
ivoices USD 15-DEC-08	0110	146100	0100	(13,357.20)
ivoices USD 16-DEC-08	0110	146100	0100	1,638,883.64
ivoices USD 16-DEC-08	0110	146100	0100	(194,569.78)
ivoices USD 17-DEC-08	0110	146100	0100	27,536.18
ivoices USD 17-DEC-08	0110	146100	0100	(64,296.00)
ivoices USD 18-DEC-08	0110	146100	0100	2,140.65
ivoices USD 19-DEC-08	0110	146100	0100	646.16
ivoices USD 19-DEC-08	0110	146100	0100	(32,665.08)
ivoices USD 20-DEC-08	0110	146100	0100	43,169.47
ivoices USD 21-DEC-08	0110	146100	0100	3,275.70
ivoices USD 22-DEC-08	0110	146100	0100	11,138.75
JSD 22-DEC-08	0110	146100	0100	8.19
ivoices USD 23-DEC-08	0110	146100	0100	4,654.01
ivoices USD 23-DEC-08	0110	146100	0100	(1,206.69)
ivoices USD 24-DEC-08	0110	146100	0100	(18.82)
ivoices USD 25-DEC-08	0110	146100	0100	407.87
ivoices USD 26-DEC-08	0110	146100	0100	1,223.83
ivoices USD 26-DEC-08	0110	146100	0100	(570,234.24)
ivoices USD 29-DEC-08	0110	146100	0100	174,441.99
ivoices USD 29-DEC-08	0110	146100	0100	(35,056.05)
ivoices USD 30-DEC-08	0110	146100	0100	82,792.27
ivoices USD 30-DEC-08	0110	146100	0100	(347,491.79)
ivoices USD 31-DEC-08	0110	146100	0100	27,340.58
ivoices USD 31-DEC-08	0110	146100	0100	(261,649.45)
ivoices USD 31-DEC-08	0110	146100	0100	270.08
ivoices USD 31-DEC-08	0110	146100	0100	(217.36)
ivoices USD 31-DEC-08	0110	146100	0100	(291.53)
TOTAL VOUCHERS				298,089.85
USD 01-DEC-08	0110	146100	0100	28,253.64
USD 28-DEC-08	0110	146100	0100	13,920.35
USD 28-DEC-08	0110	146100	0100	(15,533.45)
USD 04-DEC-08	0110	146100	0100	(45.89)
USD 01-DEC-08	0110	146100	0100	1.41
USD 08-DEC-08	0110	146100	0100	215.44
USD 09-DEC-08	0110	146100	0100	215.44

USD 11-DEC-08	0110	146100	0100	215.44
USD 12-DEC-08	0110	146100	0100	215.44
USD 10-DEC-08	0110	146100	0100	296.23
USD 28-DEC-08	0110	146100	0100	29,761.12
USD 28-DEC-08	0110	146100	0100	(64,207.28)
USD 22-DEC-08	0110	146100	0100	(105.77)
USD 23-DEC-08	0110	146100	0100	(105.77)
USD 28-DEC-08	0110	146100	0100	7,589.18
USD 30-DEC-08	0110	146100	0100	(105.77)
USD 31-DEC-08	0110	146100	0100	(105.77)
USD 29-DEC-08	0110	146100	0100	(105.77)
TOTAL LABOR				**368.22**
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	74.77
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	33,843.10
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(19,606.40)
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(0.82)
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	8,822.56
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	614.96
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	2,841.74
TL=83 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	9,730.99
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(19.02)
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(52,649.26)
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(15,425.00)
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(8,507.83)
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(721.80)
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	(5,164.08)
TL=87 DEC-2008 Burden Cost USD 31-DEC-08	0110	146100	0100	13,123.03
TOTAL BURDENS				**(33,043.06)**
PENSION?BENEFITS(F926)	0110	146100	0100	1.74
PENSION/BENEFITS(F926)	0110	146100	0100	3.28
ERATION EXPENSES	0110	146100	0100	35.96
ERATION EXPENSES	0110	146100	0100	35.96
SUPER ENGINEERING	0110	146100	0100	97.99
OF MISC OTH PWR GEN	0110	146100	0100	246.90
OF STRUCTURES	0110	146100	0100	656.06
ELLANEOUS EXPENSES	0110	146100	0100	698.08
ELLANEOUS EXPENSES	0110	146100	0100	698.16
R SUPER ENGINEER	0110	146100	0100	1,359.10
R SUPER ENGINEER	0110	146100	0100	1,359.10
SUPER AND ENGINEER.	0110	146100	0100	4,060.41
OF STRUCTURES	0110	146100	0100	5,731.20
OF GENERATING ELEC EQUIP	0110	146100	0100	7,432.36
OF MISC OTH PWR GEN	0110	146100	0100	26,361.36
OF GENER AND ELEC EQUIP	0110	146100	0100	544,685.50
ROLL TAXES CT 7 - FICA	0110	146100	0100	(1,147.80)
SION INTEREST CT 6	0110	146100	0100	(591.47)
KERS COMP CT 6	0110	146100	0100	(437.63)
SIONS CT 7	0110	146100	0100	(398.42)
106 INTEREST CT 7	0110	146100	0100	(206.46)
CAL INSURANCE CT 7	0110	146100	0100	(191.78)
112 CT 7	0110	146100	0100	(181.93)
106 CT 7	0110	146100	0100	(168.14)
CT 7	0110	146100	0100	(121.33)
ROLL TAXES CT 7 - FEDERAL	0110	146100	0100	(63.50)
TAL INSURANCE CT 6	0110	146100	0100	(37.38)
ROLL TAXES CT 7 - STATE	0110	146100	0100	(34.90)
UP LIFE INSURANCE CT 7	0110	146100	0100	(30.36)

TERM DISABILITY CT 7	0110	146100	0100	(28.59)
R BENEFITS CT 6	0110	146100	0100	(23.67)
EMENT INCOME CT 6	0110	146100	0100	(13.27)
EMENT INCOME CT 7	0110	146100	0100	3.54
R BENEFITS CT 7	0110	146100	0100	6.31
AL INSURANCE CT 7	0110	146100	0100	9.96
OLL TAXES CT 6 - STATE	0110	146100	0100	49.99
OLL TAXES CT 6 - FEDERAL	0110	146100	0100	90.95
TERM DISABILITY CT 6	0110	146100	0100	107.28
ERS COMP CT 7	0110	146100	0100	109.57
P LIFE INSURANCE CT 6	0110	146100	0100	113.91
ON INTEREST CT 7	0110	146100	0100	157.64
CT 6	0110	146100	0100	455.21
106 CT 6	0110	146100	0100	630.84
112 CT 6	0110	146100	0100	682.60
CAL INSURANCE CT 6	0110	146100	0100	719.54
106 INTEREST CT 6	0110	146100	0100	774.61
ONS CT 6	0110	146100	0100	1,494.81
OLL TAXES CT 6 - FICA	0110	146100	0100	1,644.04
OF STRUCTURES	0110	146100	0100	76.37
OF MISC OTHER PWR GEN	0110	146100	0100	226.16
OF GENERATING + ELEC EQUIP	0110	146100	0100	1,738.23
ON INTEREST	0110	146100	0100	(31.11)
ERS COMP	0110	146100	0100	(23.02)
L INSURANCE	0110	146100	0100	(1.97)
BENEFITS	0110	146100	0100	(1.24)
MENT INCOME	0110	146100	0100	(0.70)
LL TAXES - STATE	0110	146100	0100	2.47
LL TAXES - FEDERAL	0110	146100	0100	4.49
TERM DISABILITY	0110	146100	0100	5.65
LIFE INSURANCE	0110	146100	0100	5.99
	0110	146100	0100	23.93
06	0110	146100	0100	33.17
12	0110	146100	0100	35.89
AL INSURANCE	0110	146100	0100	37.84
06 INTEREST	0110	146100	0100	40.74
ONS	0110	146100	0100	78.61
LL TAXES - FICA	0110	146100	0100	81.17
OF GENERATING ELEC EQUIP	0110	146100	0100	(5,866.20)
LLANEOUS EXPENSES	0110	146100	0100	(342.35)
ONS	0110	146100	0100	(71.46)
06 INTEREST	0110	146100	0100	(33.24)
06	0110	146100	0100	(19.94)
AL INSURANCE	0110	146100	0100	(16.77)
	0110	146100	0100	(13.03)
OLL TAXES - FICA	0110	146100	0100	(12.80)
EMENT INCOME	0110	146100	0100	(3.03)
ERS COMP	0110	146100	0100	(2.79)
P LIFE INSURANCE	0110	146100	0100	(2.72)
TERM DISABILITY	0110	146100	0100	(2.46)
BENEFITS	0110	146100	0100	(1.29)
OLL TAXES - STATE	0110	146100	0100	(0.13)
L INSURANCE	0110	146100	0100	0.78
OLL TAXES - FEDERAL	0110	146100	0100	2.02
12	0110	146100	0100	25.64
ON INTEREST	0110	146100	0100	39.63
RATION EXPENSES	0110	146100	0100	(22,469.14)
OF GENERATING + ELEC EQUIP	0110	146100	0100	(13,788.98)
ONS	0110	146100	0100	(746.43)

06 INTEREST	0110	146100	0100	(347.18)
06	0110	146100	0100	(208.25)
AL INSURANCE	0110	146100	0100	(175.13)
	0110	146100	0100	(136.09)
LL TAXES - FICA	0110	146100	0100	(71.78)
EMENT INCOME	0110	146100	0100	(31.65)
ERS COMP	0110	146100	0100	(29.16)
LIFE INSURANCE	0110	146100	0100	(28.37)
TERM DISABILITY	0110	146100	0100	(25.71)
BENEFITS	0110	146100	0100	(13.49)
LL TAXES - STATE	0110	146100	0100	(0.68)
L INSURANCE	0110	146100	0100	8.12
LL TAXES - FEDERAL	0110	146100	0100	11.26
12	0110	146100	0100	267.79
ON INTEREST	0110	146100	0100	413.89
OF GENERATING + ELEC EQUIP	0110	146100	0100	(18,385.23)
RATION EXPENSES	0110	146100	0100	(9,178.48)
ONS	0110	146100	0100	(1,212.89)
06 INTEREST	0110	146100	0100	(564.13)
06	0110	146100	0100	(338.35)
AL INSURANCE	0110	146100	0100	(284.51)
	0110	146100	0100	(221.13)
LL TAXES - FICA	0110	146100	0100	(102.94)
EMENT INCOME	0110	146100	0100	(51.44)
ERS COMP	0110	146100	0100	(47.35)
LIFE INSURANCE	0110	146100	0100	(46.10)
TERM DISABILITY	0110	146100	0100	(41.75)
BENEFITS	0110	146100	0100	(21.93)
LL TAXES - STATE	0110	146100	0100	(1.00)
L INSURANCE	0110	146100	0100	13.21
LL TAXES - FEDERAL	0110	146100	0100	16.21
12	0110	146100	0100	435.14
ON INTEREST	0110	146100	0100	672.57
TOTAL CT O&M ALLOCATION				**526,118.78**
10-DEC-08	0110	146100	0100	(426.33)
18-DEC-08	0110	146100	0100	(1,187.53)
19-DEC-08	0110	146100	0100	(1,367.26)
22-DEC-08	0110	146100	0100	(4,858.80)
TOTAL MATERIALS				**(7,839.92)**
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	11,027,308.54
-1208 Other USD 01-DEC-08	0110	146100	0100	(12.19)
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	115,857.45
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	(2,776.32)
-1208 Other USD 01-DEC-08	0110	146100	0100	(104,351.65)
-1208 Other USD 01-DEC-08	0110	146100	0100	(14,147.76)
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	(147,155.98)
-1208 Adjustment USD 30-DEC-08	0110	146100	0100	223.53
D 31-DEC-08	0110	146100	0100	221,574.06
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	99.57
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	(560.69)
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	4,242.87
-1208 Other USD 01-DEC-08	0110	146100	0100	(22,122.18)
-1208 Other USD 01-DEC-08	0110	146100	0100	(58,618.52)
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	27,371.00
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	(2,000.00)
-1208 Accrual USD 01-DEC-08	0110	146100	0100	(3,510.13)
-1208 Adjustment USD 31-DEC-08	0110	146100	0100	(39.20)

1208 Accrual USD 31-DEC-08	0110	146100	0100	(194,932.56)
1208 Adjustment USD 01-DEC-08 JAN-2009	0110	146100	0100	(0.03)
1208 Adjustment USD 01-DEC-08	0110	146100	0100	7,204.90
1208 Adjustment USD 01-DEC-08	0110	146100	0100	7,656.69
1208 Other USD 01-DEC-08	0110	146100	0100	(518,133.39)
1208 Other USD 01-DEC-08	0110	146100	0100	(116,195.67)
1208 Other USD 01-DEC-08	0110	146100	0100	1,922,046.09
1208 Accrual USD 01-DEC-08	0110	146100	0100	(550,875.50)
1208 Intercompany USD 31-DEC-08 0100	0110	146100	0100	36.71
1208 Intercompany USD 31-DEC-08 0100	0110	146100	0100	96.31
1208 Adjustment USD 01-DEC-08	0110	146100	0100	135.52
1208 Adjustment USD 01-DEC-08	0110	146100	0100	(12,273.53)
1208 Adjustment USD 01-DEC-08	0110	146100	0100	(49,661.14)
1208 Adjustment USD 01-DEC-08	0110	146100	0100	(2,705,980.91)
1208 Adjustment USD 01-DEC-08	0110	146100	0100	(667,723.36)
1208 Adjustment USD 01-DEC-08	0110	146100	0100	127,684.69
1208 Adjustment USD 01-DEC-08	0110	146100	0100	(639,515.36)
025-0110-1208 Adjustment USD 01-DEC-08"08-JAN-09 09:21:06"	0110	146100	0100	(115,857.45)
045-0100-1208 Adjustment USD 01-DEC-08"08-JAN-09 09:28:33"	0110	146100	0100	667,723.36
077-0110-1208 Other USD 01-DEC-08"06-JAN-09 14:21:58"	0110	146100	0100	104,351.65
123-0020-1208 Other USD 01-DEC-08"06-JAN-09 22:24:39"	0110	146100	0100	58,618.52
173-0100-1208 Other USD 01-DEC-08"31-DEC-08 14:28:36"	0110	146100	0100	125.02
251-0110-1108 Adjustment USD 01-NOV-08"05-DEC-08 14:12:06"	0110	146100	0100	(20,659.84)
252-0110-1108 Adjustment USD 01-NOV-08"05-DEC-08 14:10:36"	0110	146100	0100	(18,255.41)
253-0110-1108 Adjustment USD 01-NOV-08"05-DEC-08 14:24:02"	0110	146100	0100	(3,426.84)
254-0110-1108 Adjustment USD 01-NOV-08"05-DEC-08 14:31:14"	0110	146100	0100	(2,927,242.18)
255-0110-1108 Adjustment USD 01-NOV-08"05-DEC-08 14:39:14"	0110	146100	0100	(354,823.65)
-1208 Adjustment USD 31-DEC-08	0110	146100	0100	(0.01)
-1208 Adjustment USD 31-DEC-08	0110	146100	0100	176,865.89
-1208 Accrual USD 31-DEC-08	0110	146100	0100	(7,886.94)
-1208 Accrual USD 31-DEC-08	0110	146100	0100	480,508.35
-1208 Adjustment USD 31-DEC-08	0110	146100	0100	3,777.41
-1208 Other USD 01-DEC-08	0110	146100	0100	58,618.52
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	(50,314.67)
-1208 Intercompany USD 31-DEC-08 0110	0110	146100	0100	28,907.82
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	6,450.66
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	(292.48)
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	501.36
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	6,933,096.87
-1208 Adjustment USD 01-DEC-08	0110	146100	0100	1,523.16
-1208 Other USD 01-DEC-08	0110	146100	0100	(125.02)
-1208 Other USD 01-DEC-08	0110	146100	0100	125.02
-1208 Other USD 01-DEC-08	0110	146100	0100	(23,908.81)
-1208 Other USD 01-DEC-08	0110	146100	0100	26,097.95
TOTAL MISCELLANEOUS J/E				12,675,450.12
TOTAL DETAIL				13,459,143.99
TOTAL ADJUSTMENT FOR ENERGY SALES (OVEC True-Up)				(1,627,730.36)
)MPANY 110 TO COMPANY 100				11,831,413.63

11,831,413.63

-

INTERCOMPANY POWER SALES AND PURCHASES

Monthly journal entries are prepared for off-system sales, off-system and native load purchases, and intercompany power sales and purchases between LG&E and KU. The After-the-Fact Billing system (AFB) is used to stack hourly energy, which allocates energy sources (generation and purchased power) to energy sinks (KU native load, LG&E native load and off-system sales (OSS).) The stacking is performed based on the energy cost where lowest cost energy is allocated to native load and highest cost energy is allocated to OSS, consistent with the companies' Power Supply System Agreement.

Outputs from the AFB program (queries) are used as inputs into an Excel spreadsheet. The spreadsheet calculates the allocation of third party and intercompany purchases between LG&E and KU. It also calculates the split between native load and off-system purchases, and uses the generation expenses for both companies to calculate the allocation of OSS between the companies.

MARGIN ACCOUNT ALLOCATION

Each month LG&E and KU participate in the purchase of forward financial power transactions with MF Global. As these transactions are settled at the end of each month, the increase or decrease to the Margin Cash Account (as well as the expense and income) is split between the two companies. This allocation is based on the split of the generation expenses for LG&E and KU, as determined by AFB (After-the-Fact Billing). AFB is the system used to stack hourly energy, which is allocated energy sources (generation and purchased power) to energy sinks (KU native load, LG&E native load, and off-system sales (OSS)). The stacking is performed based on the energy cost where lowest cost energy is allocated to native load and highest cost energy is allocated to OSS.

COSTS OF JOINTLY OWNED TRIMBLE COUNTY UNIT 2

The charges for the construction of Trimble County Unit 2 (TC2) are allocated between the joint owners, LG&E, KU, Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA). The actual capital recovery costs for TC2 are booked in the current month through either the Accounts Payable system or manual accruals, depending on the timing of the invoices submitted. TC2 accruals are received from the Project Engineering department, posted and reversed in the subsequent month. True-up of actual costs are performed on a quarterly basis to ensure that all allocation percentages are correct.

Assets constructed only for use at TC2 are allocated according to the 19% LG&E, 81% KU contractual split. Assets that will be used for both TC2 and Trimble County Unit 1 (TC1), the existing coal-fired generating unit at the Trimble County facility, are allocated using a two-step process. Charges are allocated between TC1 and TC2 based on the respective nameplate ratings (52% to LG&E and 48% to KU). Charges allocated to TC1 are recorded 100% to LG&E. Charges allocated to TC2 are split between LG&E and KU according to the 19% LG&E, 81% KU contractual split.

IMEA and IMPA have a combined 25% interest in the ownership of TC2, so 25% of the allocated amounts for both KU and LG&E are billed to IMEA and IMPA monthly and

COSTS OF JOINTLY OWNED CUSTOMER CARE SOLUTION PROJECT

The charges for the development of the Customer Care Solution (CCS) project are allocated to LGE and KU based on the ratio of a combination of revenue, total assets, and payroll calculated as of 12/31/05, which was the ratio that was available prior to the start of the project. LGE receives 52% and KU receives 48% of the expenses that cannot be specifically identified to one company. If the expenses are directly related to one company, they are charged to that company.

ALLOCATION OF BUILDING RENT

These charges are for E.ON U.S. Building rent for KU, E.ON U.S. Services Inc. (Servco), and E.ON U.S. and subsidiaries' employees occupying office space on floors four through sixteen.

The monthly accrual for rent expense for the E.ON U.S. Building is based on a levelized amortization of the total value of the rent payments. The operation and maintenance portion of the accrual is based on a monthly charge which is billed to LG&E by Louisville Financial Associates, LLC.

The allocation to LG&E, KU, Servco, and E.ON U.S. and subsidiaries is based on net labor expense for the prior year for LG&E, KU, Servco, and E.ON U.S. and subsidiaries' employees occupying the fourth through sixteenth floors for which LG&E is billed.

EXPENSES OF JOINTLY OWNED COMBUSTION TURBINES

LG&E and KU jointly own one 158-megawatt combustion turbine (CT) located at the Paddy's Run facility, six 160-megawatt CTs located at the Trimble County Generating Station (TC 5, TC 6, TC 7, TC 8, TC 9, and TC 10) and one 117-megawatt (BR 5) and two 154-megawatt (BR 6 and BR 7) CTs located at E.W. Brown facility.

All operations and maintenance expenses attributable to the Paddy's Run, Trimble County, and E.W. Brown CTs are accumulated and billed according to the percentage of ownership. The percentage of ownership is listed in the following table.

Facility	LG&E	KU
Paddy's Run 13	53%	47%
Trimble County 5	29%	71%
Trimble County 6	29%	71%
Trimble County 7	37%	63%
Trimble County 8	37%	63%
Trimble County 9	37%	63%
Trimble County 10	37%	63%
E.W. Brown 5	53%	47%
E.W. Brown 6	38%	62%
E.W. Brown 7	38%	62%

CASH COLLECTED AND PAID BY LG&E ON BEHALF OF KU

For the convenience of our suppliers and customers for purchased power and off system sales, KU and LG&E have combined their billing and payments. This gives the appearance of one company to customers and suppliers.

Internally, sales and purchases are split between KU and LG&E and each company records its payable and receivable to the appropriate account. This split is documented on the monthly spreadsheet from Energy Marketing Accounting (EMA).

As LG&E makes payments to various vendors for purchased power, the disbursement request is split into the appropriate portions applicable to each company. LG&E issues the payment through its Accounts Payable Department and bills KU for the expenditures made on behalf of KU. The Oracle General Ledger system automatically creates the Intercompany payable and receivable as transactions are posted. The amount KU owes LG&E is included on the Intercompany billing from LG&E.

As LG&E receives payments for power sales, the Credit Slip for the monies received is split into the appropriate amounts for each company. A copy of the Credit Slip is sent to Financial Accounting & Reporting, which accumulates the Credit Slips and inputs the data into a spreadsheet to prepare a monthly journal entry for the cash receipts and create a payable to KU.

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CAM	Cost Allocation Manual
Capital Corp.	E.ON U.S. Capital Corp.
EMS	Energy Management System
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Foundation	E.ON U.S. Foundation Inc.
FERC	Federal Energy Regulatory Commission
HR	Human Resources
IT	Information Technology
KU	Kentucky Utilities Company
LEM	LG&E Energy Marketing Inc.
LG&E	Louisville Gas and Electric Company
PUHCA 2005	Public Utility Holding Company Act of 2005
SA	Service Agreement
SEC	Securities Exchange Commission
SERVCO	E.ON U.S. Services Inc.
WKE	Western Kentucky Energy Corp. and its Affiliates

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I. INTRODUCTION

PUHCA 2005 states that centralized service companies must maintain and make available to the FERC their books, accounts and other records in the specific manner and preserve them for the required periods as the FERC prescribes in 18 Code of Federal Regulations Part 368 of the FERC Uniform System of Accounts. These records must be in sufficient detail to permit examination, audit, and verification, as necessary and appropriate for the protection of utility customers with respect to jurisdictional rates. The purpose of this CAM is to document the methods, policies and procedures that SERVCO will follow in performing certain services for affiliate companies. In developing this CAM the overriding goal was to protect investors and consumers by ensuring the methods, policies and procedures contained in this CAM were PUHCA 2005 compliant so that SERVCO costs are fully segregated, and fairly and equitably allocated among the affiliate companies. SERVCO was authorized to conduct business as a service company for E.ON U.S. (formerly LG&E Energy LLC) and its various subsidiaries and affiliates by order of the SEC on December 6, 2000, and commenced operations January 1, 2001.

Periodic changes to the CAM may be necessary due to future management decisions, interpretations by state or federal regulatory bodies, changes in structure or activities of affiliates, or other internal procedures.

II. DESCRIPTION OF SERVICES

Meter Reading Services – providing meter reading and meter data services.

Meter Operations Services – conducts the testing of meters, completion of all customer requested service/field credit orders and the installation of commercial/industrial meters.

Meter Asset Management Services – maintains inventory, quality and environmental issues, policy and standards, technical support, and logistics.

Cash Remittance Services – provides remittance processing, customer payments, and collection services.

Billing Integrity Services – administering and providing customer billings and credit reviews.

Energy Services

Project Engineering Services – coordinating and managing all major generation construction.

System Laboratory Services – providing system laboratory services to the generating stations.

Transmission System Operations Services – providing transmission system control center services.

Transmission EMS Services

Energy Marketing Services

Energy Marketing Services - providing market services to take advantage of the highest excess generation prices in the open market.

Market Forecasting Services – providing management services for financial forecasts of the utility market.

Load Forecasting Services – providing short- and long-term load forecasting services.

Generation Planning Services – providing short- and long-term generation planning services.

Distribution Operations Services

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Finance Organization

Finance and Corporate Development Services

Budgeting Services - providing services related to managing, coordinating and reporting for the budgeting process.

Financial Planning Services – providing services related to financial planning and forecasting services, investment analysis and investment planning reports.

Financial Systems – providing business support and electronic data processing services for all financial systems including Oracle Applications, PowerPlant and PowerTax.

Corporate Controller Organization Services

Internal Financial and Management Reporting Services – providing internal financial reports including standard and ad hoc management reporting.

External Financial Reporting Services – providing financial reports required or used by various external constituencies such as the FERC, the Kentucky Public Service Commission, the Virginia State Corporation Commission, U.S. Department of Energy

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Corporate Tax and Payroll Organization Services

Payroll Services – providing payroll services including the managing of payroll systems.

Tax Accounting, Compliance and Reporting Services – preparation of consolidated and subsidiary federal, state and local income tax returns; current and deferred tax accounting; utility gross receipts; sales/use tax; E.ON U.S. Foundation returns and supporting roles for business development, special requests and tax legislation.

Tax Planning Services – providing detailed forecasting of foreign, federal and state taxes, as well as, capital based and property tax planning.

Tax – Special Projects Services – providing business or project development, asset dispositions, tax credit studies, review/analysis of proposed tax legislation, etc.

Audit Services – providing independent and objective assurance along with consulting services and internal controls system review.

Information Technology Services

Information Technology - Corporate Functions Services – services associated with

Information Technology - Client Services – services associated with existing end user tools and related productivity software that the users can identify and interact with, such as a personal computer, telephone, email and file and print services.

Information Technology - Platform Services – services associated with shared computing platforms, databases, network and IT Service Desk.

Corporate Finance and Treasury Services

Cash Management and Investment Services – providing management and monitoring of cash flows including review and acquisition of business entity cash requirements and procurement of short-term financing and credit lines.

Corporate Finance Services – providing overall finance options including evaluation of new financing vehicles and instruments, analysis of existing financing positions and raising long-term funds for all entities.

Risk Management Services – managing outside providers of risk services comprised of providing insurance and assisting affiliated entities in managing property and liability risks including claims, security, environmental, safety and consulting services.

Materials Logistics Services – providing order management, materials handling and logistics, and inventory management services.

Sourcing Support Services – providing order management and general field support services for system policy and maintenance management, developing and monitoring of key performance metrics, and supplying day to day variance and reconciliation reporting services.

Accounts Payable Services – processing payments for purchase orders, check requests, employees' expense reimbursements, etc., and providing ad-hoc research and analysis services.

General Counsel / Secretary Organization

Compliance, Legal, and Environmental Affairs Services

Compliance and Legal Services – providing various legal and compliance services for all affiliated entities including in-house counsel and staff assistance in the areas of, among others, corporate and securities law, employment law, energy, public utility and regulatory law, contract law, litigation, environmental law and intellectual property law, evaluating

Corporate Communications and Public Affairs Management Services

Internal Communications Services

External and Brand Communications Services – providing all administrative and management support for external communication services, brand image management and corporate events.

Public Affairs Management Services – providing community relations functions, communicating public information to local organizations and providing oversight and communications to employees.

Administration Organization

Operating Services

Facilities and Building Services – providing building and grounds maintenance including coordination of office furniture and equipment purchases/leases, space utilization and layout, and building code and fire protection services.

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Human Resource Services

Human Resources – Compensation Services – providing services relating to the establishment and oversight of compensation policies for executives and employees.

Human Resources – Benefits Services – providing services relating to the establishment and oversight of benefits policies for employees, including administrative billings to vendors and retiree and survivor services, and maintenance of all personnel records.

Human Resources – Health and Safety Services – providing services relating to the establishment and oversight of health and safety policies for employees.

Human Resources – Organization Development and Training Services – providing training services to improve organizational effectiveness with an emphasis on employee and leadership development, leadership succession planning, and the change management process.

Human Resources – Corporate Headquarters Services – providing services relating to operational and strategic human resources management for corporate staff.

Human Resources – Energy Services – providing services relating to operational and

III. CORPORATE ORGANIZATION

OVERVIEW

E.ON U.S. and its utility subsidiaries are engaged principally in the generation, transmission, distribution and sale of electricity. LG&E is also engaged in the storage, distribution, and sale of natural gas. E.ON U.S. and its subsidiaries are subject to the regulatory provisions of PUHCA 2005. LG&E and KU are subject to regulation by the FERC and state utility commissions in Kentucky. KU is also subject to regulation by state utility commissions in Virginia and Tennessee.

E.ON U.S. has four direct subsidiaries: LG&E, KU, LEM, and Capital Corp., which includes WKE, E.ON U.S. Natural Gas Trading, Inc. and the Argentine Gas Distribution businesses. E.ON U.S. has an affiliate relationship with E.ON U.S. Foundation due to overseeing all operations of the foundation.

UTILITY OPERATIONS

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E is a wholly-owned subsidiary of E.ON U.S. At December 31, 2007, LG&E supplied natural gas to approximately 326,000 customers and electricity to approximately 401,000 customers in Louisville and

Many operational employees dedicated to providing a service to just one affiliate, by definition, are not subject to SERVCO placement. However management and support staff overseeing the business activities of more than one of these operational groups are subject to SERVCO placement.

OTHER BUSINESS OPERATIONS

E.ON U.S. Foundation, a charitable foundation exempt from federal income tax under Section 501(c)(3) of the Internal Revenue Code, makes charitable contributions to qualified entities.

SERVCO also transacts business with E.ON AG and its affiliates on behalf of E.ON U.S.

LEM engages in asset based energy marketing which primarily involves the marketing of power generated by non-utility physical assets controlled by E.ON U.S. and its affiliates.

Capital Corp. is the primary holding company for the E.ON U.S.'s non-utility businesses. Its businesses include:

WKE and affiliates. WKE has a 25-year lease of and operates the generating facilities of Big Rivers Electric Corporation, a power generation cooperative in western Kentucky, and a coal-fired facility owned by the City of Henderson. E.ON U.S. plans to discontinue the operations of WKE.

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At formation certain LG&E, KU and E.ON U.S. employees became employees of SERVCO and such employees continued to provide goods and services to the regulated and non-regulated entities. SERVCO provides a variety of administrative, management, engineering, construction, environmental and support services. SERVCO also coordinates the intercompany billings with E.ON and their affiliates which mainly include transactions for expatriate services.

Regulated affiliates receive services at cost, pursuant to the service agreements. Non-regulated affiliates generally receive services at cost; however, certain services may permit pricing at fair-market value. The provisions included in contracts or service agreements govern transactions between SERVCO and the regulated and non-regulated affiliates.

Definitions of Cost

Tariff Rate – The price charged to customers under applicable tariffs on file with federal or state regulatory commissions.
Fair Market Value – The price held out by a providing entity to the general public in the normal course of business (i.e. the price at which a reasonable buyer and a reasonable seller are willing to transact in the normal course of business).
Cost – The charge used for transactions with affiliates for which no tariff rate or fair market value is applicable. SERVCO follows the definition of cost defined in PUHCA 2005.

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TRANSACTIONS PROVIDED BY SERVCO TO AFFILIATES

Product or Service	**Frequency**	**Primary Affiliate**
Customer Services	Ongoing	R
Sales and Marketing Services	Frequent	R, NR
Economic Development and Major Accounts Services	Frequent	R
Meter Reading Services	Ongoing	R
Meter Operations Services	Ongoing	R
Meter Asset Management Services	Ongoing	R
Cash Remittance Services	Ongoing	R
Billing Integrity Services	Ongoing	R
Transportation Services	Ongoing	A
Project Engineering Services	Infrequent	R
System Laboratory Services	Ongoing	R
Generation Engineering Services	Ongoing	R
Combustion Turbine Operations and Maintenance Services	Ongoing	R
Fuel Procurement Services	Ongoing	R
Transmission Strategy and Planning Services	Ongoing	R

Sundry Billings Services	Ongoing	A
Property Accounting Services	Ongoing	R
Energy Marketing Accounting Services	Ongoing	A
Revenue Accounting Services	Ongoing	R
Payroll Services	Ongoing	A
Tax Accounting, Compliance and Reporting Services	Ongoing	A
Tax Planning Services	Infrequent	A
Tax – Special Projects Services	Infrequent	A
Audit Services	Ongoing	A
IT Corporate Functions Services	Ongoing	A
IT Administrative Services	Ongoing	A
IT Project Services	Frequent	A
IT Application Services	Ongoing	A
IT Client Services	Ongoing	A
IT Platform Services	Ongoing	A
Cash Management and Investment Services	Ongoing	A
Corporate Finance Services	Ongoing	A
Risk Management Services	Ongoing	A
Credit Administration Services	Ongoing	A

HR Benefits Services	Frequent	A
HR Health and Safety Services	Frequent	A
HR Organizational Development and Training Services	Frequent	A
HR Corporate Headquarters Services	Frequent	A
HR Energy Services	Frequent	R
HR Energy Delivery Services	Frequent	R
Technical and Safety Training Services	Frequent	R
Industrial Relations Management Services	Frequent	R
Executive Management Services	Ongoing	A

V. COST APPORTIONMENT METHODOLOGY

OVERVIEW

The costs of services provided by SERVCO will be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The primary basis for charges to affiliates is the direct charge method (see section VI for time reporting procedures). The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully distributed cost of providing the product or service

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SERVCO will allocate the costs of service among the affiliated companies using one of several methods that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. Any of the methods may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes in the business, but are generally determined annually. The allocation methods used by SERVCO are as follows:

Contract Ratio – Based on the sum of the physical amount (i.e. tons of coal, cubic feet of natural gas) of the contract for both coal and natural gas for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Departmental Charge Ratio – A specific SERVCO department ratio based upon various factors such as labor hours, labor dollars, departmental or entity headcount, etc. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of product or service being performed and are documented and monitored by the Budget Coordinators for each department.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating

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Number of Employees Ratio – A ratio based on the number of employees benefiting from the performance of a service. This ratio will be determined based on actual counts of applicable employees at the end of the previous calendar year. A two-step assignment methodology is utilized to properly allocate SERVCO employee costs to the proper legal entity.

Number of Meters Ratio – Ratio based on the number or types of meters being utilized by all levels of customer classes within the system for the immediately preceding twelve consecutive calendar months. The numerator is equal to the number of meters for each utility and the denominator is equal to the total meters for KU and LG&E.

Number of Transactions Ratio – Based on the sum of transactions occurring in the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. For example, services with regard to Procurement and Major Contracts would define a transaction as the number of contracts negotiated. Services pertaining to Materials Logistics would define the transaction as the number of items ordered, picked and disbursed out of the warehouse. Services pertaining to Accounts Payable would define the transaction as the number of invoices processed. The Regulatory Accounting and Reporting Department is responsible for maintaining and monitoring specific product/service methodology documentation for actual transactions related to SERVCO billings.

Payroll Ratio – Based on the sum of the payroll costs for the immediately preceding twelve consecutive

Total Assets Ratio – Based on the total assets at year end for the preceding year, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. In the event of joint ownership of a specific asset, asset ownership percentages will be utilized to assign costs.

Transportation Resource Management System Chargeback Rate – Rates for use of transportation equipment are based on the costs associated with providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities.

The following product and service listing details the type of assignments being employed.

Product or Service	Assignment Method
Customer Services	Number of Customers Ratio
Sales and Marketing Services	Departmental Charge Ratio
Economic Development and Major Account Services	Departmental Charge Ratio
Meter Reading Services	Departmental Charge Ratio
Meter Operations Services	Number of Meters Ratio

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Product or Service	**Assignment Method**
Electric Engineering Services	Departmental Charge Ratio
Distribution Asset Management Services	Total Assets Ratio
Substation Construction and Maintenance Services	Departmental Charge Ratio
Distribution Management Services	Departmental Charge Ratio
Budgeting Services	Revenue, Total Assets and Payroll Ratios
Financial Planning Services	Revenue, Total Assets and Payroll Ratios
Financial Systems	Number of Employees Ratio
Internal Financial and Management Reporting Services	Revenue, Total Assets and Payroll Ratios
External Financial Reporting Services	Revenue, Total Assets and Payroll Ratios
Accounting and Reporting Services	Revenue, Total Assets and Payroll Ratios
Accounts and Projects Services	Revenue, Total Assets and Payroll Ratios
Sundry Billings Services	Revenue, Total Assets and Payroll Ratios
Property Accounting Services	Departmental Charge Ratio
Accounts Payable Services	Number of Transactions Ratio
Energy Marketing Accounting Services	Energy Marketing Ratio
Revenue Accounting Services	Retail Revenue Ratio
Payroll Services	Payroll Ratio

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Product or Service	Assignment Method
Internal Communication Services	Departmental Charge Ratio
External and Brand Communication Services	Departmental Charge Ratio
Public Affairs Management Services	Departmental Charge Ratio
Facilities and Building Services	Departmental Charge Ratio
Security Services	Departmental Charge Ratio
Production Mail Services	Number of Customers Ratio
Document Services	Number of Employees Ratio
Right-of-Way Services	Departmental Charge Ratio
Transportation Services	Transportation Resource Management System Chargeback Rates
Procurement and Major Contracts Services	Non-Fuel Material and Services Expenditures Ratio
Strategic Sourcing Services	Non-Fuel Material and Services Expenditures Ratio
Materials Logistics Services	Number of Transactions Ratio
Sourcing Support Services	Non-Fuel Material and Services Expenditures Ratio
Accounts Payable Services	Number of Transactions Ratio
HR Compensation Services	Number of Employees Ratio
HR Benefits Services	Number of Employees Ratio
HR Health and Safety Services	Number of Employees Ratio
HR Organization Development and Training	Number of Employees Ratio

VI. TIME DISTRIBUTION, BILLING AND ASSET TRANSFER POLICIES

OVERVIEW

SERVCO utilizes ORACLE or other financial systems in which project/task combinations are set up to equate to products and services. In some cases, departments have set up many project/tasks that map to products and services. In many cases, there is a one to one relationship between the project/task and the product. The ORACLE system also automatically captures the home company (providing the service) and the charge company (receiving the service). Regardless of the method of reporting, charges related to specific products reside on the company receiving the service and therefore can be identified for billing purposes as well as for preparation of SERVCO financial statements. This ensures that:

1. Separation of costs between regulated and non-regulated affiliates will be maintained
2. Intercompany transactions and related billings are structured so that non-regulated activities are not subsidized by regulated affiliates
3. Adequate audit trails exist on the books and records

BILLING POLICIES

E.ON U.S. Services Inc.
Cost Allocation Manual

TIME DISTRIBUTION

SERVCO has three methods of distribution to record employee salaries and wages while providing services for the affiliated entities: Positive time reporting, allocation time reporting and exception time reporting. Each department's job activities will dictate the type of time reporting method used.

Positive Time Reporting

Positive time reporting or direct time reporting requires all employees of a department to track all chargeable hours every day. Time may be charged to the nearest quarter hour.

Departments that have positive time reporting have labor-based activities that are easily trackable given the project/task code combinations noted above. All employees are given appropriate project numbers that are associated with the service that is being provided. The proper coding for direct assignment of costs is on various source documents, including the Virtual Online Time System (VOLTS) and disbursement requests. Each department or project manager is responsible for ensuring employees charge the appropriate charge codes for the services performed. This form of time reporting is documented in the VOLTS, which upon completion, is approved by the employees' immediate supervisor.

Allocation Time Reporting

VIRGINIA STATE CORPORATION COMMISSION – MATRIX FILING

The Virginia State Corporation Commission requires that an Annual Report of Affiliate Transactions (Matrix filing) detailing KU's intercompany transactions be prepared and filed by May 1 of each year.

In preparation for the filing, costs between the companies are compiled and listed on the Matrix. Intercompany purchased power, off system sales, and tax settlements are excluded from the filing. The matrices are separated between KU as a provider of services (intercompany receivable) and KU as a recipient of services (intercompany payable).

See Annual Report of Affiliate Transactions for period January 1 – December 31, 2008 as filed on April 30, 2009.

an E.ON company

Old Dominion Power Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.eon-us.com

Rick E. Lovekamp
Manager - Regulatory Affairs
T 502-627-3780
F 502-627-3213
rick.lovekamp@eon-us.com

Mr. Joel Peck, Clerk
Virginia State Corporation Commission
Document Control Center
1300 East Main Street
Tyler Building 1F
Richmond, Virginia 23218

VIA UPS OVERNIGHT DELIVERY

April 30, 2009

RE: Powergen plc (*later renamed E.ON UK*), LG&E Energy Corp. (*later renamed E.ON U.S. LLC*), and Kentucky Utilities Company, d/b/a Old Dominion Power Annual Information Filing
(*Case No. PUA00020*);
Kentucky Utilities Company, Louisville Gas and Electric Company,

Mr. Joel Peck, Clerk
April 30, 2009

Further pursuant to Ordering Paragraph No. 15 of the Commission's Order in Case No. PUA00050, KU is simultaneously submitting a copy of this *Annual Report of Affiliate Transactions* to the Commission's Director of Public Utility Accounting.

Please Confirm yur receipt of this filing by placing the File Stamp of your office on the enclosed extra copy and returning it to KU in the enclosed, self-addressed envelope. If you have any questions, please contact me or contact Don Harris at 502-627-2021.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

cc: Ronald A. Gibson, Director, VSCC Division of Public Utility Accounting

KENTUCKY UTILITIES COMPANY
EXHIBIT INDEX
FOR THE PERIOD JANUARY 1, 2008 - DECEMBER 31, 2008

Exhibit VASCC - 1	E.ON U.S. Services Inc. Intercompany Cost Attribution Matrix (KU Provider of Services)
Exhibit VASCC - 1A	Annual Report of Affiliate Transactions with Louisville Gas and Electric Company (LG&E)
Exhibit VASCC - 1B	Annual Report of Affiliate Transactions with E.ON U.S. Services Inc.
Exhibit VASCC - 1C	Annual Report of Affiliate Transactions with E.ON U.S. Services Inc. (Western Kentucky Energy)
Exhibit VASCC - 1D	Annual Report of Affiliate Transactions with E.ON U.S. Services Inc. (KU Solutions)
Exhibit VASCC - 1E	Annual Report of Affiliate Transactions with E.ON U.S. Services Inc. (E.ON U.S. Capital Corp.)

KENTUCKY UTILITIES COMPANY

Exhibit No. VASCC-1

E.ON U.S. Services Inc. Intercompany Cost Attribution Matrix
(KU Provider of Services)

Services	Provider of Services		Recipient of Services		YTD
	SERVCO	KU/LG&E	SERVCO	KU/LG&E	1/08 - 12/08
OPERATIONS					
Customer Services	X		X	X	$ -
Sales & Marketing	X		X	X	$ -
Metering	X	X	X	X	$ 603,963.18
Revenue Collection	X		X	X	$ -
Generation Services	X	X	X	X	$ 76,457,988.72
Fuel Procurement	X		X	X	$ -
Transmission	X	X	X	X	$ (372,889.06)
Regulatory Affairs Management	X		X	X	$ -
Enviromental Affairs Management	X		X	X	$ -
Regulatory Power Marketing	X		X	X	$ -
Distrib. Oper. - Repair Network Process	X	X	X	X	$ 2,182,415.78
Distrib. Oper. - Enhance Network Process	X	X	X	X	$ 196.21
Distrib. Oper. - Asset Management	X	X	X	X	$ -
Distrib. Oper. - Operate & Maintain Network Process	X	X	X	X	$ 252,336.28
Distrib. Oper. - Management	X	X	X	X	$ 62,321.94
FINANCE					
Financial Planning & Budgeting	X		X	X	$ -
Accounting & Financial Reporting	X		X	X	$ -
Trading Controls/Energy Marketing Accounting	X		X	X	$ -
Payroll	X		X	X	$ -
Corporate Tax	X		X	X	$ -
Financial Systems	X		X	X	$ -
ternal Auditing	X		X	X	$

Exhibit No VASCC-1A

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LOUISVILLE GAS AND ELECTRIC COMPANY
January 1, 2008 - December 31, 2008

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and E.ON U.S. Services Inc. with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information.

1) affiliate's name;
2) description of each affiliate arrangement/agreement,
3) dates of each affiliate arrangement/agreement,
4) total dollar amount of each affiliate arrangement/agreement;
5) component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000, and
11) list by functional group of utility assets transfers valued less than $250,000

RESPONSES:

1) Louisville Gas and Electric Company (LG&E)

2) Services Agreement Case Nos. PUA970048, PUA000050

3) May 4, 1998 & January 1, 2001

4) $78,796,179.71

5) Component costs are:

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
E.ON U.S. SERVICES INC
January 1, 2008 - December 31, 2008

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and E.ON U.S. Services Inc with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999 Such report should include the following information:

1) affiliate's name;
2) description of each affiliate arrangement/agreement;
3) dates of each affiliate arrangement/agreement;
4) total dollar amount of each affiliate arrangement/agreement;
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6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000.

RESPONSES:

1) E.ON U.S. Services Inc

2) Services Agreement Case No. PUA000050

3) January 1, 2001

4) $1,093,940.96

5) Component costs are:

Exhibit No VASCC-1C

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
E.ON U.S. SERVICES INC. (WESTERN KENTUCKY ENERGY CORP.)
January 1, 2008 - December 31, 2008

No 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided

RESPONSES:

1) E ON U S Services Inc (Western Kentucky Energy Corp.)

2) Distribution Operations-Management
Generation Services
Information Technology Operations

3)	Distribution Operations-Management	May - December 2008
	Generation Services	March, April, June, November 2008
	Information Technology Operations	January - December 2008

4)	Distribution Operations-Management	$ 2,713.98
	Generation Services	$ 1,754.53
	Information Technology Operations	$ 52,955.98
		$ 57,424.49

Exhibit No VASCC-1D

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
E.ON U.S. SERVICES INC. (KU SOLUTIONS)
January 1, 2008 - December 31, 2008

No 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided,
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i e , direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided

RESPONSES:

1) E.ON U.S Services Inc (KU Solutions)

2) Metering

3) Metering — January - December 2008

4) $602,242.69

5) Component costs are:

Direct - Indirect Labor	$	598,295 68
Fringe Benefits/Overheads	$	3,343 29
Travel/Housing	$	-
Materials	$	79 74
Supplies	$	-
Indirect Miscellaneous Expenses (Vouchers)	$	-

Exhibit No. VASCC-1E

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
E.ON U.S. SERVICES INC. (E.ON U.S. CAPITAL CORP.)
January 1, 2008 - December 31, 2008

No 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) E.ON U.S. Services Inc. (E.ON U.S. Capital Corp.)

2) Information Technology Operations
Distribution Operations - Management
Distribution Operations - Operate/Maintain Network Process
Building Operations & Maintenance Services
Generation Services
Strategic Sourcing
Transmission

3)

Information Technology Operations	January - December 2008
Distribution Operations - Management	June 2008
Distribution Operations - Operate/Maintain Network Process	January, February, June, August 2008
Building Operations & Maintenance Services	February - December 2008
Generation Services	April, June, July, November, December 2008

Exhibit No VASCC-1F

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
E.ON U.S. SERVICES INC. (LEM CONTINUING OPERATIONS)
January 1, 2008 - December 31, 2008

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) E.ON U.S. Services Inc. (LEM Continuing Operations)

2) Information Technology Operations

3) Information Technology Operations — January - December 2008

4) $22,451.00

5) Component costs are:

Direct - Indirect Labor	$	10,890.56
Fringe Benefits/Overheads	$	7,835.59
Travel/Housing	$	361.56
Materials	$	-
Supplies	$	-

KENTUCKY UTILITIES COMPANY

Exhibit No. VASCC-2

E.ON U.S. Services Inc. Intercompany Cost Attribution Matrix
(KU Recipient of Services)

Services	Provider of Services		Recipient of Services		YTD
	SERVCO	KU/LG&E	SERVCO	KU/LG&E	1/08 - 12/08
OPERATIONS					
Customer Services	X		X	X	$ 5,670,142.62
Sales & Marketing	X		X	X	$ 7,443,399.84
Metering	X		X	X	$ 371,446.50
Revenue Collection	X		X	X	$ 1,176,893.45
Generation Services	X		X	X	$ 19,753,871.61
Fuel Procurement	X		X	X	$ 490,935,405.36
Transmission	X	X	X	X	$ 16,578,179.23
Regulatory Affairs Management	X		X	X	$ 2,196,927.10
Enviromental Affairs Management	X		X	X	$ -
Regulatory Power Marketing	X		X	X	$ 2,974,785.52
Distrib. Oper. - Repair Network Process	X	X	X	X	$ 451,623.85
Distrib. Oper. - Enhance Network Process	X	X	X	X	$ 641,362.48
Distrib. Oper. - Asset Management	X	X	X	X	$ 1,842,421.57
Distrib. Oper. - Operate & Maintain Network Process	X	X	X	X	$ 7,078,982.70
Distrib. Oper. - Management	X		X	X	$ 1,308,827.07
FINANCE					
Financial Planning & Budgeting	X		X	X	$ 1,390,235.10
Accounting & Financial Reporting	X		X	X	$ 2,960,111.48
Trading Controls/Energy Marketing Accounting	X		X	X	$ 320,294.17
Payroll	X		X	X	$ (4,588,199.12)
Corporate Tax	X		X	X	$ 463,503.67
Financial Systems	X		X	X	$ 185,208.69
Internal Auditing	X		X	X	$ 737,733.58
Information Technology Strategy, Planning, & Security	X	X	X	X	$ 2,330,249.93
...rmation Technology Operations	X	X	X	X	$ 53,474,677.74

Exhibit No. VASCC-2A

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH LOUISVILLE GAS AND ELECTRIC COMPANY
January 1, 2008 - December 31, 2008

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and E.ON U.S. Services Inc. with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) affiliate's name;
2) description of each affiliate arrangement/agreement;
3) dates of each affiliate arrangement/agreement;
4) total dollar amount of each affiliate arrangement/agreement;
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6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000.

RESPONSES:

1) Louisville Gas and Electric Company (LG&E)

2) Services Agreement Case Nos. PUA970048, PUA000050

3) May 4, 1998 & January 1, 2001

4) $80,866,190.31

5) Component costs are:

Direct - Indirect Labor $ [illegible]

Exhibit No. VASCC-2B

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
E.ON U.S. SERVICES INC.
January 1, 2008 - December 31, 2008

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and E.ON U.S. Services Inc. with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) affiliate's name;
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3) dates of each affiliate arrangement/agreement;
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7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000.

RESPONSES:

1) E.ON U.S. Services Inc.

2) Services Agreement Case No. PUA000050

3) January 1, 2001

4) $670,399,181.66

5) Component costs are:

ENTITY EVENTS – 2008

None

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

Form 60 Approved
OMB No. 1902-0215
Expires 02/28/2010

FERC FINANCIAL REPORT
FERC FORM No. 60: Annual Report of Centralized Service Companies

GENERAL INSTRUCTIONS FOR FILING FERC FORM NO. 60

I. Purpose

Form No. 60 is an annual regulatory support requirement under 18 CFR 369.1for centralized service companies. The report is designed to collect financial information from centralized service companies subject to the jurisdiction of the Federal Energy Regulatory Commission. The report is considered to be a non-confidential public use form.

II. Who Must Submit

Unless the holding company system is exempted or granted a waiver by Commission rule or order pursuant to §§ 18 CFR 366.3 and 366.4 of this chapter, every centralized service company (see § 367.2) in a holding company system must prepare and file electronically with the Commission the FERC Form No. 60 then in effect pursuant to the General Instructions set out in this form.

III. How to Submit

Submit FERC Form No. 60 electronically through the Form No. 60 Submission Software. Retain one copy of each report for your files. For any resubmissions, submit the filing using the Form No. 60 Submission Software including a justification. Respondents must submit the Corporate Officer Certification electronically.

IV. When to Submit

Submit FERC Form No. 60 according to the filing date contained § 18 CFR 369.1 of the Commission's regulations.

V. Preparation

X. Date Format

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

XI. Number Format

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 use of a minus sign.

XII. Required Entries

Do not make references to reports of previous years or to other reports instead of required entries, except as specifically authorized.

XIII. Prior Year References

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

XIV. Where to Send Comments on Public Reporting Burden

The public reporting burden for the Form No. 60 collection of information is estimated to average 75 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.

Send comments regarding these burden estimates or any aspect of this collection of information, including suggestions for reducing burden, to:

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent)N U.S. Services Inc.	02 Year of Report Dec 31, 2008
03 Previous Name (If name changed during the year)	04 Date of Name Change / /
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 220 West Main Street, Louisville, KY 40202	06 Name of Contact Person Mimi Kelly
07 Title of Contact Person Manager Regulatory Accounting and Reporting	08 Address of Contact Person 220 West Main Street, Louisville, KY 40202
09 Telephone Number of Contact Person (502) 627-2482	10 E-mail Address of Contact Person Mimi.Kelly@eon-us.com
11 This Report is: (1) [X] An Original (2) [ ] A Resubmission	12 Resubmission Date (Month, Day, Year) / /
13 Date of Incorporation 06/02/2000	14 If Not Incorporated, Date of Organization / /
15 State or Sovereign Power Under Which Incorporated or Organized KENTUCKY	

Name of Principal Holding Company Under Which Reporting Company is Organized:

Name of Respondent E. ON U.S. Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2008

List of Schedules and Accounts

1. Enter in Column (c) the terms "None" or "Not Applicable" as appropriate, where no information or amounts have been reported for ain pages.

Line No.	Description (a)	Page Reference (b)	Remarks (c)
1	Schedule I - Comparative Balance Sheet	101-102	
2	Schedule II - Service Company Property	103	
3	Schedule III - Accumulated Provision for Depreciation and Amortization of Service Company Property	104	
4	Schedule IV - Investments	105	None
5	Schedule V - Accounts Receivable from Associate Companies	106	
6	Schedule VI - Fuel Stock Expenses Undistributed	107	
7	Schedule VII - Stores Expense Undistributed	108	
8	Schedule VIII - Miscellaneous Current and Accrued Assets	109	None
9	Schedule IX - Miscellaneous Deferred Debits	110	None
10	Schedule X - Research, Development, or Demonstration Expenditures	111	None
11	Schedule XI - Proprietary Capital	201	
12	Schedule XII - Long-Term Debt	202	None
13	Schedule XIII - Current and Accrued Liabilities	203	
14	Schedule XIV - Notes to Financial Statements	204	
15	Schedule XV - Comparative Income Statement	301-302	
16	Schedule XVI - Analysis of Charges for Service - Associate and Nonassociate Companies	303-306	
17	Schedule XVII - Analysis of Billing – Associate Companies (Account 457)	307	
	Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)	308	None

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule I - Comparative Balance Sheet

1. Give balance sheet of the Company as of December 31 of the current and prior year.

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		**Service Company Property**			
2	101	Service Company Property	103	3,522,577	3,466,819
3	101.1	Property Under Capital Leases	103		
4	106	Completed Construction Not Classified			
5	107	Construction Work In Progress	103	904,154	177,483
6		Total Property (Total Of Lines 2-5)		4,426,731	3,644,302
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104	2,598,590	1,855,535
8	111	Less: Accumulated Provision for Amortization of Service Company Property			
9		Net Service Company Property (Total of Lines 6-8)		1,828,141	1,788,767
10		**Investments**			
11	123	Investment In Associate Companies	105		
12	124	Other Investments	105		
13	128	Other Special Funds	105		
14		Total Investments (Total of Lines 11-13)			
15		**Current And Accrued Assets**			
16	131	Cash			
17	134	Working Funds			
18	135	Other Special Deposits			
	136	Temporary Cash Investments			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule I - Comparative Balance Sheet (continued)

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		**Proprietary Capital**			
49	201	Common Stock Issued	201	100	100
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	900	900
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201		
54	219	Accumulated Other Comprehensive Income	201	(78,085,061)	(36,990,128)
55		Total Proprietary Capital (Total of Lines 49-54)		(78,084,061)	(36,989,128)
56		**Long-Term Debt**			
57	223	Advances From Associate Companies	202		
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)			
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current			
64	228.2	Accumulated Provision for Injuries and Damages			
65	228.3	Accumulated Provision For Pensions and Benefits		180,302,576	101,113,788
	230	Asset Retirement Obligations			

Name of Respondent ON U.S. Services Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2008

FOOTNOTE DATA

Schedule Page: 101 Line No.: 32 Column: d

Page 109 is a supporting schedule for account 174 - Miscellaneous Current and Accrued Assets. It should be referenced in column (c) on this line.

Schedule Page: 101 Line No.: 33 Column: d

Page 109 is a supporting schedule for account 174 - Miscellaneous Current and Accrued Assets. It should not be referenced in column (c) on this line.

Schedule Page: 101 Line No.: 42 Column: d

Page 110 is a supporting schedule for account 186 - Miscellaneous Deferred Debits. It should be referenced in column (c) on this line.

Schedule Page: 101 Line No.: 43 Column: d

Page 111 is a supporting schedule for account 188 - Research, Development, or Demonstration Expenditures. It should be referenced in column (c) on this line.

Schedule Page: 101 Line No.: 44 Column: d

Page 111 is a supporting schedule for account 188 - Research, Development, or Demonstration Expenditures. It should not be referenced in column (c) on this line.

Name of Respondent E. ON U.S. Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2008

Schedule II - Service Company Property

1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote.
Describe each construction work in progress on lines 18 through 30 in Column (b).

Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment	3,466,819	55,758			3,522,577
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
	399.1	Asset Retirement Costs					

Name of Respondent E. ON U.S. Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2008

Schedule III – Accumulated Provision for Depreciation and Amortization of Service Company Property

1. Provide an explanation of Other Charges in Column (f) considered material in a footnote.

Line No.	Account Number (a)	Description (b)	Balance at Beginning of Year (c)	Additions Charged To Account 403-403.1 404-405 (d)	Retirements (e)	Other Changes Additions (Deductions) (f)	Balance at Close of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment	1,855,535	712,756		30,299	2,598,590
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
ON U.S. Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2008

FOOTNOTE DATA

Schedule Page: 104 Line No.: 6 Column: f

Removal Work In Progress (RWIP) for assets to be retired

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule IV – Investments

1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with scription including the name of issuing company, number of shares held or principal investment amount.
. For temporary cash investments (Account 136), list each investment separately in a footnote.
3. Investments less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	123	Investment In Associate Companies		
2	124	Other Investments		
3	128	Other Special Funds		
4	136	Temporary Cash Investments		
5		(Total of Lines 1-4)		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule V – Accounts Receivable from Associate Companies

1. List the accounts receivable from each associate company.
If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		E.ON AG	347,901	271,940
4		E.ON Energie AG	6,705	212
5		E.ON Kraftwerke GmbH	24,104	40,995
6		E.ON Ruhrgas AG	14,206	44,244
7		E.ON Sverige AB	3,196	
8		E.ON U.S. Capital Corp.	44,885,944	48,002,836
9		E.ON U.S. LLC	2,287,471	2,416,363
10		E.ON U.S. Natural Gas Trading Inc.	22,984	370
11		E.ON UK plc	58,777	6,603
12		FCD LLC		460
13		FSF Minerals Inc.		400
14		Kentucky Utilities Company	25,326,928	24,709,458
15		LG&E Energy Marketing Inc.	7,027,311	307,446
16		LG&E International Inc.	307,169	111,020
17		LG&E Power Development Inc.	17,666	
18		LG&E Power Inc.	25,704	7,320
19		Louisville Gas and Electric Company	18,960,320	19,785,051
[illegible]		[illegible]	2,350,221	2,390,445

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
ON U.S. Services Inc.	(1) X An Original (2) _ A Resubmission	/ /	2008

FOOTNOTE DATA

Schedule Page: 106   Line No.: 39   Column: b

Analysis of convenience or accomodation payments:

Associate Company	Amount
E.ON U.S. Capital Corp.	$ 242,977
Kentucky Utilities Company	517,687,754
LG&E Energy Marketing Inc.	1,221
LG&E Home Services Inc.	27
LG&E International Inc.	15,822
LG&E Power Inc.	1,335
Louisville Gas and Electric Company	365,369,951
Western Kentucky Energy Corp.	7,466,303
Total	$ 890,785,390

Convenience payments result primarily from the following items:

Description	Amount
401(h) Contributions	$ 3,101,827
401(k) Plan	5,280,810
Coal, Fuel Oil, and Limestone Purchases	825,923,521
Dental Claims	1,711,493
...ess Liability Insurance	34,808

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule VI – Fuel Stock Expenses Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and licate amount attributable to each associate company.
In a separate footnote, describe in a narrative the fuel functions performed by the service company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3		None		0	
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					

Name of Respondent ON U.S. Services Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2008

FOOTNOTE DATA

Schedule Page: 107 Line No.: 3 Column: d

Fuel functions provided by the service company include the following:

- Procurement of coal, fuel oil, scrubber reagent, ammonia, and SO3 mitigation chemicals
- Transportation service to move these commodities from the loading point to the power plant
- Monitoring of quality, inventory level, and forecasted requirements
- Making purchases as needed on a timely basis
- Preparing bid solicitation for coal, and other commodities, as neecessary, and evaluating those bids
- Negotiating and writing the contracts and purchase orders
- Contract administration

Fuel Procurement department expenses for 2008 were $2,803,277.

Name of Respondent E. ON U.S. Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2008

Schedule VII – Stores Expense Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to stores expense during the year and licate amount attributable to each associate company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3		None		0	
4					
5					
6					
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14					
15					
16					
17					
18					
19					

Name of Respondent ON U.S. Services Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2008

FOOTNOTE DATA

Schedule Page: 108 Line No.: 3 Column: d

Stores Expense was fully distributed for 2008.

2008 Expenses Distibuted by Associate Company

Associate Company	Expenses
E.ON U.S. Capital Corp.	$ 18,505
Kentucky Utilities Company	56,852
Louisville Gas and Electric Company	74,963
Western Kentucky Energy Corp.	9,644
Total	$ 159,964

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule VIII - Miscellaneous Current and Accrued Assets

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	174	**Miscellaneous Current and Accrued Assets**		
2		**Item List:**		
3		None		
4				
5				
6				
7				
8				
9				
10				
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12				
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14				
15				
16				
17				
18				
19				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule IX - Miscellaneous Deferred Debits

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	186	**Miscellaneous Deferred Debits**		
2		**Items List:**		
3		None		
4				
5				
6				
7				
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14				
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18				
19				
20				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule X - Research, Development, or Demonstration Expenditures

1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the ar. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	**Research, Development, or Demonstration Expenditures**	
2		**Project List:**	
3		None	
4			
5			
6			
7			
8			
9			
10			
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12			
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19			
20			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule XI - Proprietary Capital

1. For miscellaneous paid-in capital (Account 211) and appropriate retained earnings (Account 215), classify amounts in each account, ı a brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.
For the unappropriated retained earnings (Account 216), in a footnote, give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentages, amount of dividend, date declared and date paid.

Line No.	Account Number (a)	Title of Account (b)	Description (c)	Amount (d)
1	201	Common Stock Issued	Number of Shares Authorized	1,000
2			Par or Stated Value per Share	
3			Outstanding Number of Shares	100
4			Close of Period Amount	100
5		Preferred Stock Issued	Number of Shares Authorized	
6			Par or Stated Value per Share	
7			Outstanding Number of Shares	
8			Close of Period Amount	
9	211	Miscellaneous Paid-In Capital		900
10	215	Appropriated Retained Earnings		
11	219	Accumulated Other Comprehensive Income		(78,085,061)
12	216	Unappropriated Retained Earnings	Balance at Beginning of Year	
13			Net Income or (Loss)	
14			Dividend Paid	
15			Balance at Close of Year	

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
ON U.S. Services Inc.	(1) X An Original (2) _ A Resubmission	/ /	2008

FOOTNOTE DATA

Schedule Page: 201 Line No.: 9 Column: d

Capital contributed in March 2001

Name of Respondent E. ON U.S. Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2008

Schedule XII – Long Term Debt

1. For the advances from associate companies (Account 223), describe in a footnote the advances on notes and advances on open :ounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation Column (c).
2. For the deductions in Column (h), please give an explanation in a footnote.
3. For other long-term debt (Account 224), list the name of the creditor company or organization in Column (b).

Line No.	Account Number (a)	Title of Account (b)	Term of Obligation Class & Series of Obligation (c)	Date of Maturity (d)	Interest Rate (e)	Amount Authorized (f)	Balance at Beginning of Year (g)	Additions Deductions (h)	Balance at Close of Year (i)
1	223	Advances from Associate Companies							
2		Associate Company:							
3		None							
4									
5									
6									
7									
8									
9									
10									
11									
12									
13		TOTAL							

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
E. ON U.S. Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2008

Schedule XIII – Current and Accrued Liabilities

1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234).

Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than $50,000 may be ouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	233	Notes Payable to Associates Companies	0	0
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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18				

Name of Respondent E. ON U.S. Services Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2008
Schedule XIV- Notes to Financial Statements			

1. Use the space below for important notes regarding the financial statements or any account thereof. 2. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year. 3. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year. 4. Furnish particulars as to any amounts recorded in Account 434, Extraordinary Income, or Account 435, Extraordinary Deductions. 5. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference. 6. Describe the annual statement supplied to each associate service company in support of the amount of interest on borrowed capital and compensation for use of capital billed during the calendar year. State the basis for billing of interest to each associate company. If a ratio, describe in detail how ratio is computed. If more than one ratio explain the calculation. Report the amount of interest borrowed and/or compensation for use of capital billed to each associate company.

Note 1 – Organization of Servco

E.ON U.S. Services Inc. (Servco), a Kentucky corporation, is a wholly-owned subsidiary of E.ON U.S. LLC (E.ON U.S.), and a centralized service company under the Public Utility Holding Company Act of 2005 (PUHCA 2005). E.ON U.S. is an indirect wholly-owned subsidiary of E.ON AG (E.ON). On June 15, 2006, E.ON U.S. and E.ON registered as public utility holding companies under PUHCA 2005. Servco was authorized to conduct business as a service company for E.ON U.S. (formerly LG&E Energy LLC) and its various subsidiaries and affiliates by order of the Securities and Exchange Commission (SEC) dated December 6, 2000, and commenced operations January 1, 2001.

Servco provides certain services to affiliated entities, including E.ON U.S., E.ON U.S. Capital Corp. (Capital Corp.), LG&E Energy Marketing Inc. (LEM), Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), at cost as permitted under PUHCA 2005. The Company is organized along functional lines to accomplish its purpose of providing management, administrative, and technical services. These services are priced so that Servco operates on a break-even basis.

change. See also Note 7, Income Taxes.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environmental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Reclassifications. Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on previously-reported total assets, total liabilities and member's equity, or net income.

Recent Accounting Pronouncements.

FASB Staff Position (FSP) 132(R)-1

In December 2008, the FASB issued FSP SFAS No. 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*, which will be effective as of December 31, 2009. FSP 132(R)-1 requires additional disclosures related to pension and other postretirement benefit plan assets. Additional disclosures include the investment allocation decision-making process, the fair value of each major category of plan assets as well as former subsidiary be initially measured at fair value when a subsidiary is deconsolidated. SFAS No. 160 also sets forth the disclosure requirements to identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. SFAS No. 160 must be applied prospectively as of the beginning of the fiscal year in which SFAS No. 160 is initially applied, except for the presentation and disclosure requirements. The presentation and disclosure requirements are applied retrospectively for all periods presented. The Company does not anticipate that the initial application of SFAS No. 160 will have an impact on the Company.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 was adopted effective January 1, 2008, and Servco chose not to elect the fair value option for its eligible financial assets and liabilities.

SFAS No. 157

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 - Include other inputs that are directly or indirectly observable in the marketplace.

- Level 3 - Unobservable inputs which are supported by little or no market activity.

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

In accordance with SFAS No. 157, the Company measures the liability listed in the table below at fair value. The Company classifies its liability for the E.ON share performance plan within level 2 because it is valued using a model that considers the quoted market price of E.ON's common shares traded on the Frankfurt Stock Exchange as well as other economic measures. See Note 9, Stock Appreciation Rights (SAR) and Share Performance Plan.

Assets and liabilities measured at fair value as of December 31, 2008 are summarized below (in millions of $):

	Quoted Prices In Active Markets For	Significant Other	Significant

Intercompany billings from Servco are listed on page 307, Analysis of Billing – Associate Companies (Account 457). These billings do not include convenience payments which are shown as a footnote to page 106, line 39, column b.

Money Pool

Servco administers the Utility Money Pool and the Non-Utility Money Pool, including recordkeeping and coordination of loans, to more effectively utilize cash resources and to reduce external short-term borrowings. Utility Money Pool participants include E.ON U.S., KU, and LG&E. E.ON U.S. acts only as a lender, while KU and LG&E can be borrowers or lenders. The Non-Utility Money Pool participants include E.ON U.S., Capital Corp., LEM, E.ON Natural Gas Trading Inc., LG&E Power Development Inc., LG&E Power Inc., and LG&E Power Operations Inc. All Non-Utility Money Pool participants except for E.ON U.S. can be a borrower or a lender. E.ON U.S. serves only as a lender.

Note 6 - Pension and Other Postretirement Benefit Plans

Pension Plans and Other Postretirement Benefits. Servco employees benefit from both funded and unfunded noncontributory defined benefit pension plans and other postretirement benefit plans sponsored by E.ON U.S. that together cover employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account (RIA), a defined contribution plan. The Company makes an annual lump sum contribution to the RIA, based on years of service and a percentage of covered compensation. The health care

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Change in benefit obligation				
Benefit obligation at beginning of year	$ 232	$ 218	$ 19	$ 20
Service cost	9	10	1	1
Interest cost	16	14	1	1
Benefits paid, net of retiree contributions	(3)	(3)	-	-
Actuarial (gain)/loss and other	22	(7)	-	(3)
Benefit obligation at end of year	$ 276	$ 232	$ 21	$ 19
Change in plan assets				
Fair value of plan assets at beginning of year	$ 141	$ 100	$ 8	$ 6
Actual return/(loss) on plan assets	(35)	9	(2)	-
Employer contributions	4	35	3	2
Benefits paid, net of retiree contributions	(3)	(3)	-	-
Fair value of plan assets at end of year	$ 107	$ 141	$ 9	$ 8

	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Accrued benefit liability – current	$ (2)	$ (1)	$ -	$ -
Accrued benefit liability – non-current	(167)	(90)	(12)	(11)
Amounts recognized in accumulated OCI consist of:				
Transition obligation	$ -	$ -	$ -	$ -
Prior service cost	(26)	(29)	(1)	(1)
Accumulated loss	(97)	(29)	(4)	(1)
Total accumulated OCI	$(123)	$ (58)	$ (5)	$ (2)
Additional year-end information for plans with benefit obligations in excess of plan assets:				
Benefit obligation	$ 276	$ 232	$ 21	$ 19
Accumulated benefit obligation	195	162	-	-
Fair value of plan assets	107	141	9	8

The amounts recognized in accumulated OCI for the years ended December 31 are composed of the following (in millions of $):

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Service cost	$ 9	$ 10	$1	$1
Interest cost	16	14	1	1
Expected return on plan assets	(12)	(11)	-	-
Amortization of prior service cost	3	3	-	-
Amortization of actuarial loss	1	3	-	-
Net periodic benefit cost	$ 17	$ 19	$2	$2

The estimated amounts that will be amortized from accumulated OCI into net periodic benefit cost in 2009 follow (in millions of $):

	Pension Benefits	Other Postretirement Benefits
Accumulated OCI:		
Net actuarial loss	$6	$-
Prior service cost	3	-

	2008	2007
Discount rate	6.66%	5.96%
Expected long-term rate of return on plan assets	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, Servco considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate could have an approximate $31 million positive or negative impact on the 2008 accumulated benefit obligation and an approximate $49 million positive or negative impact on the 2008 projected benefit obligation.

- A 25-basis point change in the expected rate of return on assets would have less than $1 million positive or negative impact on 2008 pension expense.

	Target Range	2008	2007
Equity securities	45%-75%	55%	57%
Debt securities	30%-50%	43%	43%
Other	0%-10%	2%	0%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, the MSCI-EAFE Index, Lehman Aggregate and Lehman U.S. Long Government Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. In April 2009, the Company made a contribution to the pension plan of approximately $8 million.

Servco made contributions to its other postretirement benefit plans of $3 million in 2008 and $2 million in 2007. In 2009, Servco plans on making voluntary contributions to fund VEBA trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company has monitored developments regarding the Act and has made a number of elections to comply with it.

Thrift Savings Plan. Servco has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under these plans, eligible employees may defer and contribute to the plans a portion of current compensation in order to provide future retirement benefits. The Company makes contributions to the plans by matching a

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Components of income tax expense are shown in the table below for the year ended December 31, (in millions of $):

	2008	2007
Current – federal	$ 4	$ 8
Current – state	1	1
Deferred – federal – net	(4)	(8)
Deferred – state – net	(1)	(1)
Total income tax expense	$ 0	$ 0

The decrease in current federal income tax expense and increase in deferred federal income tax expense in 2008 from 2007 resulted from the timing of the deduction of pension-related expenses. Total income tax expense and pretax income for 2008 and 2007 was $0.

Components of net deferred tax assets in the balance sheet are shown below as of December 31, (in millions of $):

	2008	2007
Deferred tax assets:		
Pensions and similar obligations	$77	$45

Note 9 - Stock Appreciation Rights and Share Performance Plan

Certain executives of the Company participated in the E.ON Stock Appreciation Rights program, a stock-based compensation plan based on E.ON's shares. E.ON stopped issuing SARs to officers after the 2005 grant, and all of the remaining SARs outstanding were exercised in 2007. There were no SARs outstanding at December 31, 2008, or December 31, 2007. The Company recorded no SAR expense in 2008 and it recorded SAR expense of less than $1 million in 2007.

In 2006, a new stock-based compensation system, the E.ON Share Performance Plan, was introduced, and virtual shares were granted under the Plan to certain executives of Servco for the first time. The E.ON Share Performance Plan is a stock-based compensation plan based on the value of E.ON's shares, and it entitles each participant to receive a payment at the end of a three-year period equal to a target value per share times the number of virtual shares granted. The number of virtual shares cannot change during the three-year period, but the target value per share can change based on E.ON's stock price and the performance of E.ON stock during the three-year period compared to the change in the Dow Jones STOXX Utilities Index (Total Return EUR). Servco uses the fair-value method to account for the Plan. See Note 3, Fair Value Measurements.

The table below shows the number of virtual shares issued to E.ON U.S. executives and outstanding under the E.ON Share Performance Plan.

Share balance at December 31, 2006	8,725

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Schedule XV- Comparative Income Statement

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
1		**SERVICE COMPANY OPERATING REVENUES**		
2	400	Service Company Operating Revenues	342,250,441	
3		**SERVICE COMPANY OPERATING EXPENSES**		
4	401	Operation Expenses	170,449,683	
5	402	Maintenance Expenses	21,692,101	
6	403	Depreciation Expenses	712,756	
7	403.1	Depreciation Expense for Asset Retirement Costs		
8	404	Amortization of Limited-Term Property		
9	405	Amortization of Other Property		
10	407.3	Regulatory Debits		
11	407.4	Regulatory Credits		
12	408.1	Taxes Other Than Income Taxes, Operating Income	6,984,053	
13	409.1	Income Taxes, Operating Income	1,786,067	
14	410.1	Provision for Deferred Income Taxes, Operating Income	9,261,164	
15	411.1	Provision for Deferred Income Taxes – Credit , Operating Income	(11,047,231)	
16	411.4	Investment Tax Credit, Service Company Property		
	411.6	Gains from Disposition of Service Company Plant		

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Schedule XV- Comparative Income Statement (continued)

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions	100	
42	409.2	Income Taxes, Other Income and Deductions	2,885,343	
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions	(2,885,343)	
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions		
45	411.5	Investment Tax Credit, Other Income Deductions		
46		**TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)**	100	
47		**INTEREST CHARGES**		
48	427	Interest on Long-Term Debt		
49	428	Amortization of Debt Discount and Expense		
50	429	(less) Amortization of Premium on Debt- Credit		
51	430	Interest on Debt to Associate Companies		
52	431	Other Interest Expense		
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit		
54		**TOTAL INTEREST CHARGES (Total of Lines 48-53)**		
55		**NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)**		
56		**EXTRAORDINARY ITEMS**		
	434	Extraordinary Income		

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies

1. Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of 'ing schedules.

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
1	403-403.1	Depreciation Expense	712,756		712,756			
2	404-405	Amortization Expense						
3	407.3-407.4	Regulatory Debits/Credits – Net						
4	408.1-408.2	Taxes Other Than Income Taxes	988,523	5,995,630	6,984,153			
5	409.1-409.3	Income Taxes	4,671,411		4,671,411			
6	410.1-411.2	Provision for Deferred Taxes	6,375,821		6,375,821			
7	411.1-411.2	Provision for Deferred Taxes – Credit	(11,047,231)		(11,047,231)			
8	411.6	Gain from Disposition of Service Company Plant						
9	411.7	Losses from Disposition of Service Company Plant						
10	411.4-411.5	Investment Tax Credit Adjustment						
11	411.10	Accretion Expense						
12	412	*Costs and Expenses of Construction or Other* Services	122,105,291		122,105,291			
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies						
14	418	Non-operating Rental Income						
15	418.1	Interest and Dividend Income						
16	419.1	Allowance for Other Funds Used During Construction						
17	421	Miscellaneous Income or Loss						
		Gain on Disposition of Property						

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
35	535-540.1	Total Hydraulic Power Generation Operation Expenses	2,539		2,539			
36	541-545.1	Total Hydraulic Power Generation Maintenance Expenses						
37	546-550.1	Total Other Power Generation Operation Expenses						
38	551-554.1	Total Other Power Generation Maintenance Expenses	939		939			
39	555-557	Total Other Power Supply Operation Expenses	74,756	2,598,698	2,673,454			
40	560	Operation Supervision and Engineering	68,168	3,124,352	3,192,520			
41	561.1	Load Dispatch-Reliability		1,782,341	1,782,341			
42	561.2	Load Dispatch-Monitor and Operate Transmission System						
43	561.3	Load Dispatch-Transmission Service and Scheduling						
44	561.4	Scheduling, System Control and Dispatch Services						
45	561.5	Reliability Planning and Standards Development						
46	561.6	Transmission Service Studies	54,312		54,312			
47	561.7	Generation Interconnection Studies						
	561.8	Reliability Planning and Standards Development Services						

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
69	575.1-575.8	Total Regional Market Operation Expenses						
70	576.1-576.5	Total Regional Market Maintenance Expenses						
71	580-589	Total Distribution Operation Expenses	4,861,771	2,050,558	6,912,329			
72	590-598	Total Distribution Maintenance Expenses	358,591		358,591			
73		Total Electric Operation and Maintenance Expenses	155,563,541	23,892,065	179,455,606			
74	800-812	Total Other Gas Supply Operation Expenses	(408)		(408)			
75	814-826	Total Underground Storage Operation Expenses	9,366		9,366			
76	830-837	Total Underground Storage Maintenance Expenses	800		800			
77	840-842.3	Total Other Storage Operation Expenses						
78	843.1-843.9	Total Other Storage Maintenance Expenses						
79	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses						
80	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses						
81	850	Operation Supervision and Engineering						
82	851	System Control and Load Dispatching.						
83	852	Communication System Expenses						
84	853	Compressor Station Labor and Expenses						

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
105	902	Meter reading expenses	132,400	61	132,461			
106	903	Customer records and collection expenses	8,330,654	4,971,275	13,301,929			
107	904	Uncollectible accounts						
108	905	Miscellaneous customer accounts expenses	567,701	95	567,796			
109	906	Total Customer Accounts Operation Expenses						
110	907	Supervision	176,450	276,538	452,988			
111	908	Customer assistance expenses	33,446	1,201,065	1,234,511			
112	909	Informational And Instructional Advertising Expenses	268,582		268,582			
113	910	Miscellaneous Customer Service And Informational Expenses	3,085,308	531,813	3,617,121			
114		Total Service and Informational Operation Accounts	14,725,851	7,548,929	22,274,780			
115	911	Supervision						
116	912	Demonstrating and Selling Expenses						
117	913	Advertising Expenses	116,323		116,323			
118	916	Miscellaneous Sales Expenses						
119		Total Sales Operation Expenses	116,323		116,323			
120	920	Administrative and General Salaries	9,021,763	32,164,050	41,185,813			
121	921	Office Supplies and Expenses	6,387,911	11,630,378	18,018,289			

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense	712,756		712,756
2	404-405	Amortization Expense			
3	407.3-407.4	Regulatory Debits/Credits – Net			
4	408.1-408.2	Taxes Other Than Income Taxes	988,523	5,995,630	6,984,153
5	409.1-409.3	Income Taxes	4,671,411		4,671,411
6	410.1-411.2	Provision for Deferred Taxes	6,375,821		6,375,821
7	411.1-411.2	Provision for Deferred Taxes – Credit	(11,047,231)		(11,047,231)
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment			
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services	122,105,291		122,105,291
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies			
14	418	Non-operating Rental Income			
15	418.1	Interest and Dividend Income			
16	419.1	Allowance for Other Funds Used During Construction			
17	421	Miscellaneous Income or Loss			

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	535-540.1	Total Hydraulic Power Generation Operation Expenses	2,539		2,539
36	541-545.1	Total Hydraulic Power Generation Maintenance Expenses			
37	546-550.1	Total Other Power Generation Operation Expenses			
38	551-554.1	Total Other Power Generation Maintenance Expenses	939		939
39	555-557	Total Other Power Supply Operation Expenses	74,756	2,598,698	2,673,454
40	560	Operation Supervision and Engineering	68,168	3,124,352	3,192,520
41	561.1	Load Dispatch-Reliability		1,782,341	1,782,341
42	561.2	Load Dispatch-Monitor and Operate Transmission System			
43	561.3	Load Dispatch-Transmission Service and Scheduling			
44	561.4	Scheduling, System Control and Dispatch Services			
45	561.5	Reliability Planning and Standards Development			
46	561.6	Transmission Service Studies	54,312		54,312
47	561.7	Generation Interconnection Studies			
	561.8	Reliability Planning and Standards Development Services			

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	575.1-575.8	Total Regional Market Operation Expenses			
70	576.1-576.5	Total Regional Market Maintenance Expenses			
71	580-589	Total Distribution Operation Expenses	4,861,771	2,050,558	6,912,329
72	590-598	Total Distribution Maintenance Expenses	358,591		358,591
73		Total Electric Operation and Maintenance Expenses	155,563,541	23,892,065	179,455,606
74	800-812	Total Other Gas Supply Operation Expenses	(408)		(408)
75	814-826	Total Underground Storage Operation Expenses	9,366		9,366
76	830-837	Total Underground Storage Maintenance Expenses	800		800
77	840-842.3	Total Other Storage Operation Expenses			
78	843.1-843.9	Total Other Storage Maintenance Expenses			
79	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses			
80	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses			
81	850	Operation Supervision and Engineering			
82	851	System Control and Load Dispatching.			
83	852	Communication System Expenses			
84	853	Compressor Station Labor and Expenses			
		Gas for Compressor Station Fuel			

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
105	902	Meter reading expenses	132,400	61	132,461
106	903	Customer records and collection expenses	8,330,654	4,971,275	13,301,929
107	904	Uncollectible accounts			
108	905	Miscellaneous customer accounts expenses	567,701	95	567,796
109	906	Total Customer Accounts Operation Expenses			
110	907	Supervision	176,450	276,538	452,988
111	908	Customer assistance expenses	33,446	1,201,065	1,234,511
112	909	Informational And Instructional Advertising Expenses	268,582		268,582
113	910	Miscellaneous Customer Service And Informational Expenses	3,085,308	531,813	3,617,121
114		Total Service and Informational Operation Accounts	14,725,851	7,548,929	22,274,780
115	911	Supervision			
116	912	Demonstrating and Selling Expenses			
117	913	Advertising Expenses	116,323		116,323
118	916	Miscellaneous Sales Expenses			
119		Total Sales Operation Expenses	116,323		116,323
120	920	Administrative and General Salaries	9,021,763	32,164,050	41,185,813
121	921	Office Supplies and Expenses	6,387,911	11,630,378	18,018,289

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Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	E.ON U.S. Capital Corp.	23,185,303	6,490,313		29,675,616
2	E.ON U.S. LLC	22,029			22,029
3	E.ON U.S. Natural Gas Trading Inc.	491,384	746		492,130
4	Kentucky Utilities Company	94,684,475	54,724,115		149,408,590
5	LG&E Energy Marketing Inc.	590,446	2,095,423		2,685,869
6	LG&E International Inc.	747,349	34,220		781,569
7	LG&E Power Development Inc.	13,315	2,158		15,473
8	LG&E Power Inc.	30,055	1,805		31,860
9	Louisville Gas and Electric Company	93,617,320	51,633,271		145,250,591
10	Western Kentucky Energy Corp.	10,253,951	3,632,763		13,886,714
11					
12					
13					
14					
15					
16					
17					
18					
19					

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
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Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)

1. For services rendered to nonassociate companies (Account 458), list all of the nonassociate companies. In a footnote, describe services rendered to each respective nonassociate company.

Line No.	Name of Non-associate Company (a)	Account 458.1 Direct Costs Charged (b)	Account 458.2 Indirect Costs Charged (c)	Account 458.3 Compensation For Use of Capital (d)	Account 458.4 Excess or Deficiency on Servicing Non-associate Utility Companies (e)	Total Amount Billed (f)
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						

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Schedule XIX - Miscellaneous General Expenses - Account 930.2

1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according ıeir nature. Amounts less than $50,000 may be grouped showing the number of items and the total for the group.
ayments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

Line No.	Title of Account (a)	Amount (b)
1	Association Dues - American Gas Association	128,126
2	Association Dues - Edison Electric Institute	927,911
3	Broker Fees	53,303
4	Business License Fees	180,274
5	Other Miscellaneous General Expenses	87,706
6	Research and Development Expenses - Electric Power Research Institute	1,792,829
7	Research Work Direct	65,000
8	Research Work Indirect	412,182
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		

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FOOTNOTE DATA

Schedule Page: 307 Line No.: 5 Column: a

Other Miscellaneous General Expenses include 16 items that are less than $50,000 each.

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Schedule XX - Organization Chart			

1. Provide a graphical presentation of the relationships and inter relationships within the service company that identifies lines of authority and responsibility in the organization.

The following are officers of E.ON U.S. Services Inc. as of March 31, 2009:

Victor A. Staffieri -- *Chairman, Chief Executive Officer and President* *

John R. McCall -- *Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance officer* *

Paula H. Pottinger -- *Senior Vice President, Human Resources*
Michael S. Beer -- *Vice President, Federal Regulation and Policy*
Lonnie E. Bellar -- *Vice President -- State Regulation and Rates*
Laura G. Douglas -- *Vice President, Corporate Responsibility and Community Affairs*
R.W. "Chip" Keeling -- *Vice President, Communications*
Dorothy E. O'Brien -- *Vice President and Deputy General Counsel, Legal and Environmental Affairs*
George R. Siemens -- *Vice President, External Affairs*

S. Bradford Rives -- *Chief Financial Officer* *

Kent W. Blake -- *Vice President, Corporate Planning and Development*
Daniel K. Arbough -- *Treasurer* *
Valerie L. Scott -- *Controller*

Paul W. Thompson -- *Senior Vice President, Energy Services*

D. Ralph Bowling -- *Vice President, Power Production*
David S. Sinclair -- *Vice President, Energy Marketing*
John N. Voyles, Jr. -- *Vice President, Transmission and Generation Services*

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Schedule XXI - Methods of Allocation

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.

2. Include any other allocation methods used to allocate costs.

Service Department or Function	Basis of Allocation
Customer Services	Number of Customers Ratio
Sales and Marketing Services	Departmental Charge Ratio
Economic Development and Major Account Services	Departmental Charge Ratio
Meter Reading Services	Departmental Charge Ratio
Meter Operations Services	Number of Meters
Meter Asset Management Services	Number of Meters
Cash Remittance Services	Revenue Ratio
Billing Integrity Services	Number of Customers Ratio
Project Engineering Services	Total Assets Ratio
System Laboratory Services	Departmental Charge Ratio
Generation Engineering Services	Departmental Charge Ratio
Combustion Turbine Operations and Maintenance Services	Total Assets Ratio
Fuel Procurement Services	Contract Ratio
Transmission Strategy and Planning Services	Departmental Charge Ratio
Transmission Protection and Substation Services	Departmental Charge Ratio
Transmission Line Services	Departmental Charge Ratio
Transmission Reliability and Compliance Services	Departmental Charge Ratio

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Schedule XXI - Methods of Allocation

Services	
Tax Planning Services	Departmental Charge Ratio
Tax – Special Projects Services	Direct Charges Ratio
Audit Services	Project Ratio
IT Corporate Functions Services	Information Systems Chargeback Rates
IT Administrative Services	Information Systems Chargeback Rates
IT Project Services	Information Systems Chargeback Rates
IT Application Services	Information Systems Chargeback Rates
IT Client Services	Information Systems Chargeback Rates
IT Platform Services	Information Systems Chargeback Rates
Cash Management and Investment Services	Revenue, Total Assets and Payroll Ratios
Corporate Finance Services	Revenue, Total Assets and Payroll Ratios
Risk Management Services	Outsourced - Direct Charges Only
Credit Administration Services	Energy Marketing Ratio
Energy Marketing Trading Controls Services	Energy Marketing Ratio
Energy Marketing Contract Administration Services	Energy Marketing Ratio
Strategic Planning Services	Direct Charges Only
Compliance and Legal Services	Departmental Charge Ratio
Environmental Affairs Services	Departmental Charge Ratio
Regulatory Affairs Services	Revenue Ratio
Government Affairs Management Services	Departmental Charge Ratio
Internal Communications Services	Departmental Charge Ratio
External and Brand Communication Services	Departmental Charge Ratio
Public Affairs Management Services	Departmental Charge Ratio
Facilities and Building Services	Departmental Charge Ratio
Security Services	Departmental Charge Ratio

affected affiliate companies.

Departmental Charge Ratio – A specific Servco department ratio based upon various factors such as labor hours, labor dollars, departmental or entity headcount, etc. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of product or service being performed and are documented and monitored by the Budget Coordinators for each department.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies.

Energy Marketing Ratio – Based on the absolute value of equivalent megawatt hours purchased or sold for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Information Systems Chargeback Rates – Rates for services, including but not limited to software, consulting, mainframe and personal computer services, are based on the costs of labor, materials and information services overheads related to the provision of each service. Such rates are applied based on the specific equipment employed and the measured usage of services by client entities.

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
E. ON U.S. Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2008

Schedule XXI - Methods of Allocation

warehouse. Services pertaining to Accounts Payable would define the transaction as the number of invoices processed. The Regulatory Accounting and Reporting Department is responsible for maintaining and monitoring specific product/service methodology documentation for actual transactions related to Servco billings.

Payroll Ratio – Based on the sum of the payroll costs for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Project Ratio – Based on the total costs for any departmental or affiliate project for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Regulatory Mandate Ratios – Based on federal or state mandated percentage allocations based on regulatory proceedings and requirements. These ratios are typically developed in concert with regulatory authorities representing the results of merger or joint asset ownership negotiations and are supported by specific contracts regarding legal entity allocation requirements. Contract terms are maintained by the Regulatory Accounting and Reporting Department.

Retail Revenue Ratio – Based on utility revenues, excluding energy marketing revenues, for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Revenue Ratio – Based on the sum of the revenue for the immediately preceding twelve consecutive calendar months

PLOYEES TRANSFERRED

	New Job Title	Eff Date
vices Inc.	Electric System Coordinator I	2008-12-29
vices Inc.	System Administrator Senior	2008-11-03
vices Inc.	Building Operations Technician	2008-06-30
vices Inc.	Dept/Div Secretary	2008-01-14
vices Inc.	Bill Translator Associate II	2008-03-10
vices Inc.	Electric System Coordinator I	2008-12-29
vices Inc.	Mgr Sys Restoration & Disp Ops	2008-06-16
vices Inc.	Business Center Rep	2008-08-11
vices Inc.	Customer Care Rep	2008-12-29
vices Inc.	Grp Ldr Trans System Ops Eng	2008-12-22
vices Inc.	System Administrator Intermed	2008-10-06
vices Inc.	Sr Engineer	2008-08-18
vices Inc.	Business Center Rep	2008-03-10
vices Inc.	Electric System Coordinator i	2008-05-05
vices Inc.	Electric System Coordinator I	2008-10-13
vices Inc.	Inspector - Transmission Lines	2008-04-21
vices Inc.	System Administrator Intermed	2008-02-25
vices Inc.	E.ON Graduate Program Engineer	2008-09-22
vices Inc.	Engineer I	2008-01-01
vices Inc.	Meter Reading Clerk II	2008-03-10
vices Inc.	Customer Care Rep	2008-06-23