From: Harris, Donald
To: Lovekamp, Rick; Conroy, Robert
Sent: 10/20/2009 4:03:26 PM
Subject: Q3 Utility Reports
Attachments: KU Draft 2 Q309 (djh).doc; LGE Draft 2 Q309 (djh).doc

Hello. Would you please review the financial reports? I only had a few changes from the original submission. I need to submit by midday tomorrow. Thanks.

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Don Harris
Rate & Regulatory Analyst
502-627-2021 Telephone

Kentucky Utilities Company

Financial Statements and Additional Information

(Unaudited)

As of September 30, 2009 and December 31, 2008
and for the three-month and nine-month periods ended
September 30, 2009 and 2008

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
APB	Accounting Principles Board
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury 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
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. Services Inc.
EPA	U.S. Environmental Protection Agency
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.
FSP	FASB Staff Position
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
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
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
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Ratings 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

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
OPERATING REVENUES				
Total operating revenues (Note 8)	$ 344	$ 371	$ 1,010	$ 1,039
OPERATING EXPENSES				
Fuel for electric generation	114	147	329	380
Power purchased (Note 8)	46	54	154	164
Other operation and maintenance expenses (Note 2)	23	67	230	208
Depreciation and amortization	34	36	99	99
Total operating expenses	217	304	812	851
Operating income	127	67	198	188
Other expense (income) – net (Note 3)	2	(13)	(6)	(31)
Interest expense (Note 6)	2	3	5	10
Interest expense to affiliated companies (Notes 6 and 8)	18	15	51	41
Income before income taxes	105	62	148	168
Federal and state income tax expense (Note 5)	39	19	49	51
Net income	$ 66	$ 43	$ 99	$ 117

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

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Balance at beginning of period	$ 1,228	$ 1,111	$ 1,195	$ 1,037
Net income	66	43	99	117
Balance at end of period	$ 1,294	$ 1,154	$ 1,294	$ 1,154

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

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

ASSETS	September 30, 2009	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 4	$ 2
Restricted cash	-	9
Accounts receivable, net:		
Customer – less reserves of $4 million and $3 million as of September 30, 2009 and December 31, 2008, respectively	138	152
Other – less reserves of less than $1 million as of September 30, 2009 and December 31, 2008	31	32
Materials and supplies:		
Fuel (predominantly coal)	91	73
Other materials and supplies	39	36
Regulatory assets (Note 2)	36	32
Prepayments and other current assets	6	10
Total current assets	345	346
Other property and investments	13	23
Utility plant:		
At original cost	4,764	4,446
Less: reserve for depreciation	1,768	1,724
Total utility plant, net	2,996	2,722
Construction work in progress	1,182	1,176
Total utility plant and construction work in progress	4,178	3,898
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	127	127
Other	117	64
Cash surrender value of key man life insurance	37	39
Other assets	10	11
Total deferred debits and other assets	291	241
Total assets	$ 4,827	$ 4,508

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, 2009	December 31, 2008
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 228	$ 228
Notes payable to affiliated companies (Notes 6 and 8)	23	16
Accounts payable	131	155
Accounts payable to affiliated companies (Note 8)	31	38
Deferred income taxes – net (Note 5)	25	30
Customer deposits	22	21
Regulatory liabilities (Note 2)	8	5
Other current liabilities	41	33
Total current liabilities	509	526
Long-term debt:		
Long-term bonds (Note 6)	123	123
Long-term debt to affiliated company (Notes 6 and 8)	1,281	1,181
Total long-term debt	1,404	1,304
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	305	250
Accumulated provision for pensions and related benefits (Note 4)	189	186
Investment tax credit (Note 5)	97	80
Asset retirement obligations	34	32
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	328	329
Deferred income taxes - net	10	16
Other	10	15
Other liabilities	24	26
Total deferred credits and other liabilities	997	934
Common equity:		
Common stock, without par value -		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital (Note 8)	315	241
Retained earnings	1,283	1,174
Undistributed subsidiary earnings	11	21
Total retained earnings	1,294	1,195
Total common equity	1,917	1,744
Total liabilities and equity	$ 4,827	$ 4,508

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, 2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 99	$ 117
Items not requiring cash currently:		
Depreciation and amortization	100	99
Deferred income taxes – net	48	(3)
Investment tax credit	17	22
Provision for pension and post retirement plans	19	7
Undistributed earnings of subsidiary company	10	(3)
Changes in current assets and liabilities:		
Accounts receivable	15	4
Materials and supplies	(21)	(19)
Accounts payable	(12)	15
Accrued income taxes	(1)	7
Prepayments and other current assets	1	1
Other current liabilities	5	4
Pension and postretirement funding (Note 4)	(17)	(2)
Storm restoration regulatory asset	(57)	-
Fuel adjustment clause, net	6	4
Environmental cost recovery	(9)	(8)
Other	(13)	(2)
Net cash provided by operating activities	190	243
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(378)	(554)
Assets transferred from affiliate	-	(10)
Restricted cash	9	10
Net cash used for investing activities	(369)	(554)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Additional paid-in capital (Note 8)	75	125
Long-term borrowings from affiliated company (Note 6)	100	175
Short-term borrowings from affiliated company – net (Note 6)	6	93
Reacquired bonds (Note 6)	-	(80)
Net cash provided by financing activities	181	313
CHANGE IN CASH AND CASH EQUIVALENTS	2	2
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2	-
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 4	$ 2

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

Note 1 - General

The unaudited financial statements include the accounts of KU. The Company'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 ("Annual Report") for the year ended December 31, 2008, including the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2009 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

ASU 2009-05

In August 2009, the FASB issued ASU 2009-05, *Fair Value Measurements and Disclosures,* an update to ASC 820, which is effective for the first reporting period beginning after issuance. ASU 2009-05 provides amendments to clarify and reduce ambiguity in valuation techniques, adjustments and measurement criteria for liabilities measured at fair value. The adoption of ASU 2009-05 will have no impact on the Company's results of operations, financial position or liquidity.

SFAS No. 168 (ASC 105-10)

In June 2009, the FASB issued SFAS No. 168 (ASC 105-10), *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles,* which is effective for interim and annual periods ending after September 15, 2009. SFAS No. 168 (ASC 105-10) establishes the FASB Accounting Standards Codification ("Codification") as the single source of authoritative nongovernmental U.S. generally accepted accounting principles ("GAAP"). In addition, SFAS No. 168 (ASC 105-10) replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which developed the Codification and identified the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP in the United States. SFAS No. 168 (ASC 105-10) will have no effect on the Company's results of operations, financial position or liquidity, however, references to authoritative accounting literature have changed with the adoption.

SFAS No. 165 (ASC 855-10)

In May 2009, the FASB issued SFAS No. 165 (ASC 855-10), *Subsequent Events,* which is effective for interim and annual periods ending after June 15, 2009. SFAS No. 165 (ASC 855-10) requires disclosure of the date through which subsequent events have been evaluated, as well as whether that date is the date the financial statements were issued or the date they were available to be issued. The adoption of SFAS No. 165 (ASC 855-10) had no impact on the Company's results of operations, financial position or liquidity, however, additional disclosures were required with the adoption.

FSP SFAS 107-1 and APB 28-1 (ASC 825-10)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 (ASC 825-10), *Interim Disclosures about Fair Value of Financial Instruments,* which is effective for interim and annual periods ending after June 15, 2009, and requires qualitative and quantitative disclosures about fair values of assets and liabilities on a quarterly basis. The adoption of FSP SFAS 107-1 and APB 28-1 (ASC 825-10) had no impact on the Company's results of operations, financial position or liquidity, however, additional disclosures were required with the adoption. See Note 3, Financial Instruments, for additional disclosures.

FSP SFAS 132(R)-1 (ASC 715-20)

In December 2008, the FASB issued FSP SFAS 132(R)-1 (ASC 715-20), *Employers' Disclosures about Postretirement Benefit Plan Assets,* which will be effective as of December 31, 2009, and requires additional disclosures related to pension and other postretirement benefit plan assets. Additional disclosures include the investment allocation decision-making process, the fair value of each major category of plan assets as well as the inputs and valuation techniques used to measure fair value and significant concentrations of risk within the plan assets. The adoption of FSP SFAS 132(R)-1 (ASC 715-20) will have no impact on the Company's results of operations, financial position or liquidity, however, additional disclosures will be required with the adoption.

SFAS No. 161 (ASC 815-10)

In March 2008, the FASB issued SFAS No. 161 (ASC 815-10), *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 (ASC 815-10). The adoption of SFAS No. 161 (ASC 815-10) had no impact on KU's statements of operations, financial position and cash flows, however, additional disclosures relating to derivatives were required with the adoption effective January 1, 2009.

SFAS No. 160 (ASC 810-10)

In December 2007, the FASB issued SFAS No. 160 (ASC 810-10), *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 adopted SFAS No. 160 (ASC 810-10) effective January 1, 2009, and it had no impact on its statements of operations, financial position and cash flows.

SFAS No. 157 (ASC 820-10)

In September 2006, the FASB issued SFAS No. 157 (ASC 820-10), *Fair Value Measurements*, which, except as described below, was 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 (ASC 820-10) does not expand the application of fair value accounting to new circumstances.

In February 2008, the FASB issued FSP SFAS 157-2 (ASC 820-10), *Effective Date of FASB Statement No. 157,* which delayed the effective date of SFAS No. 157 (ASC 820-10) 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 (ASC 820-10) have been evaluated and have no impact on the Company's financial statements.

The Company adopted SFAS No. 157 (ASC 820-10) effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and it 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 FSP SFAS 157-2 (ASC 820-10), fair value accounting for all nonrecurring fair value measurements of nonfinancial assets and liabilities was adopted effective January 1, 2009, and it had no impact on the statements of operations, financial position and cash flows. At September 30, 2009, no additional disclosures were required per FSP SFAS 157-2 (ASC 820-10) as KU did not have any nonfinancial assets or liabilities measured at fair value subsequent to initial measurement. In April 2009, the FASB issued FSP SFAS 157-4 (ASC 820-10), *Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions that are not Orderly,* which is effective for interim and annual periods ending after June 15, 2009. FSP SFAS 157-4 (ASC 820-10) provides additional guidance on determining fair values when there is no active market or where the price inputs being used represent distressed sales. The adoption of FSP SFAS 157-4 (ASC 820-10) had no impact on the Company's financial position, statements of operations and cash flows.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2 of KU's Annual Report for the year ended December 31, 2008.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflects a proposed rate of return on rate base of 8.586% based upon a return on equity of 12%. The Virginia Commission has suspended the increased rates through October 31, 2009. The rate case application is subject to further proceedings before the Virginia Commission, including filings by interested parties, potential intervenors or the public. Certain testimony or other filings are anticipated in November and December 2009 and hearings are currently scheduled for November 2009 and January 2010. Following the suspension period, KU has the option, at its discretion, of implementing the proposed rates on an interim basis, subject to potential refund with interest, pending the outcome of the overall proceeding. [update]

Kentucky Rate Case

In January 2009, KU, the AG, KIUC and all other parties to the base rate case filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, KU's base rates will decrease $9 million annually. An Order approving the settlement was received in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, which will result in increased revenues of approximately $16 million 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 requested a shift from current, all-in stated unit charge rates to an unbundled formula rate. In May 2009, as a result of settlement negotiations, KU submitted an unopposed motion informing the FERC of the filing of a settlement agreement and agreed-upon seven-year service agreements with the municipal customers. The unopposed motion requested interim rate structures containing terms corresponding to the overall settlement principles, to be effective from May 1, 2009, until FERC approval of the settlement agreement. The settlement and service agreements provide for unbundled formula rates which are subject to annual adjustment and approval processes. In May 2009, the FERC issued an Order approving the interim settlement with respect to rates effective May 1, 2009 representing increases of approximately 3% from prior charges and a return on equity of 11%. Additionally, during May 2009, KU filed the first annual adjustment to the formula rates to incorporate 2008 data, which adjusted formula rates became effective on July 1, 2009.

Separately, the parties were not able to reach agreement on the issue of whether KU must allocate to the municipal customers a portion of renewable resources it procures on behalf of its retail ratepayers. This issue will remain subject to further FERC proceedings and rulings or possible future settlement negotiations. [update for FERC August acceptance and 10/9 deadline]

Regulatory Assets and Liabilities

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

(in millions)	September 30, 2009	December 31, 2008
Current regulatory assets:		
ECR	$ 30	$ 20
FAC	2	8
Net MISO exit	2	-
Other	2	4
Total current regulatory assets	$ 36	$ 32
Non-current other regulatory assets:		
Storm restoration	$ 57	$ -
ARO	29	28
Unamortized loss on bonds	13	13
Net MISO exit	9	19
Hurricane Ike	2	2
Other	7	2
Subtotal non-current other regulatory assets	117	64
Pension and postretirement benefits	127	127
Total non-current regulatory assets	$ 244	$ 191
Current regulatory liabilities:		
DSM	$ 8	$ 5
Total current regulatory liabilities	$ 8	$ 5
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 328	$ 329
Deferred income taxes – net	10	16
Other	10	15
Total non-current regulatory liabilities	$ 348	$ 360

KU does not currently earn a rate of return on the ECR and FAC regulatory assets and the Virginia levelized fuel factor included in other regulatory assets, 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. KU will recover this asset through 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. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. A return is earned on the unamortized loss on bonds, and these costs are recovered through amortization over the life of the debt. The Company will seek recovery of the Storm restoration and Hurricane Ike regulatory assets and other regulatory assets, including the CMRG and KCCS contributions and FERC jurisdictional pension expense, in its next base rate cases. The Company recovers the net MISO exit regulatory asset in Kentucky incurred through April 30, 2008. The Company will also seek recovery of other jurisdictional portions of this asset in its current Virginia base rate case and, due to the formula nature of its FERC rate structure, the FERC jurisdictional portion of the regulatory asset will be included in the annual updates to the rate formula. The Company recovers the remaining regulatory assets, including other regulatory assets comprised of merger surcredit, deferred storm costs, EKPC FERC transmission settlement agreement and Kentucky rate case expenses. Other regulatory liabilities include DSM, FERC jurisdictional supplies inventory and MISO administrative charges collected via base rates from May 2008 through February 5, 2009. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, per a Kentucky Commission Order, in the next Kentucky base rate case.

ECR. In August 2009, the Kentucky Commission initiated a two year review of KU's environmental surcharge for the period ending April 2009. An order is anticipated in the first quarter of 2010.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. The Company anticipates an order by the end of 2009, and recovery on customer bills through the monthly ECR surcredit beginning February 2010. [update]

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 February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%.

In January 2009, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the period ending October 31, 2008. The Kentucky Commission issued an Order in July 2009, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments for under-recovered costs and the rate of return on capital.

FAC. In August 2009, the Kentucky Commission initiated a routine examination of the FAC for the 6-month period November 1, 2008 through April 30, 2009. A formal hearing was held on October 13, 2009. An Order is anticipated in the fourth quarter of 2009.

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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. The Kentucky Commission issued an Order in June 2009, approving the charges and credits billed through the FAC during the review period.

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.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any over- or under-recovery of fuel expenses from the prior year. At September 30, 2009, KU had a regulatory asset of less than $1 million. In February 2009, KU filed an application with the Virginia Commission seeking approval of a 29% increase in its fuel cost factor beginning with service rendered in April 2009. In February 2009, the Virginia Commission issued an Order allowing the requested change to become effective on an interim basis. The Virginia Staff testimony filed in April 2009, recommended a slight decrease in the factor filed by KU. The Company indicated the Virginia Staff proposal is acceptable. A hearing was held in May 2009, with general resolution of remaining issues. In May 2009, the Virginia Commission issued an Order approving the revised fuel factor, representing an increase of 24%, effective May 2009.

MISO. In accordance with Kentucky Commission Orders approving the MISO exit, KU has established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via Kentucky base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges 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. Based upon the 2008 FERC Orders, the Company 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. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of less than $1 million, which the MISO began refunding back to the Company in June 2009, and which were fully collected by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of $1 million of expense. Further developments in the RSG proceeding could occur during 2009. Due to the numerous participants, complex principles at issue and changes from prior precedents, the Company cannot predict the ultimate outcome of this matter nor can it predict the impact of the various proposals that have been made by the parties. [update]

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

$64 million of operation and maintenance expenses and $34 million of capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 winter storms.

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.

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.

Other Regulatory Matters

Wind Power Agreements. In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intention to file an application for approval of a wind purchase power contract and a cost recovery mechanism. The contract was executed in August 2009, and is contingent upon KU and LG&E receiving acceptable regulatory approvals. In September 2009, the Company filed an application and supporting testimony with the Kentucky Commission. [monitor updates]

Trimble County Asset Transfer and Depreciation. KU and LG&E are currently constructing a new base-load, coal fired unit, TC2, which will be jointly owned by KU and LG&E, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency. In July 2009, KU and LG&E notified the Kentucky Commission of the proposed transfer from LG&E to KU of certain ownership interests in certain existing Trimble County generating station assets which are anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests being transferred are intended to provide KU an ownership interest in these common assets that is proportional to its interest in TC2. It is anticipated that the assets will be transferred at a price equal to the net book value associated with the proportional interests at the time of the transfer.

The assets have a net book value of approximately $50 million as of June 2009. This transfer is expected to be made upon the beginning of TC2 unit testing which is estimated to be December 2009.

In August 2009, in a separate proceeding, KU and LG&E jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable TC2-related generating, pollution control and other plant equipment and assets. The filing requests common depreciation rates for the applicable jointly-owned TC2-related assets, rather than applying differing depreciation rates in place with respect to KU's and LG&E's separately-owned base-load generating assets. In September 2009, data discovery was initiated by the Kentucky Commission and continues through November 2009. A ruling is requested prior to December 2009. [update]

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.

TC2 CCN Application and Transmission Matters. A CCN application for construction of TC2 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. In April 2009, the Kentucky Supreme Court granted a motion for discretionary review filed by KU and LG&E in May 2008. The discretionary review request, which seeks reversal of the appellate court decision and reinstatement of the Circuit Court dismissal of the challenge, may be ruled upon during 2009.

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 obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation and easement rights. In August 2008, the landowners appealed such rulings to the Kentucky Court of Appeals and received a stay preventing KU from accessing the properties during the appeal. In April 2009, the appellate court denied a KU motion to lift the stay and issued an Order generally (i) retaining the stay until a decision on the merits and (ii) delaying such decision on the merits pending developments in the Supreme Court CCN proceeding mentioned above. After unsuccessfully seeking reconsideration of this ruling by the Court of Appeals and expedited review by the Kentucky Supreme Court in May 2009, KU filed a motion with the Kentucky Supreme Court for discretionary review of the appellate court order affirming the stay in June 2009. That motion is pending.

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.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. 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.

During March 2009, owners of an airfield in Jefferson County, Indiana, filed a petition with the Federal Aviation Administration ("FAA") seeking review of a prior FAA determination regarding certain transmission towers to be constructed at a crossing point of the Ohio River. The FAA previously determined that the towers do not constitute a hazard to air navigation, but such ruling is not deemed final until the review is completed. The receipt of a favorable final FAA determination is necessary for a tall structure permit in Indiana. This matter was resolved favorably through settlement with the owners of the airfield in May 2009.

On September 3, 2009, KU filed an application with the KPSC concerning the need to obtain a CPCN for the construction of temporary transmission facilities in Hardin County, KY. An informal conference took place on October 13, 2009 at the KPSC offices. Data discovery continues through November 2009. The KPSC must issue a decision by January 1, 2010.

KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the transmission line approval, land acquisition and permitting proceedings.

Deleted: [update for September filings/CCN Order]

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreement in the rate case established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission which approved the implementation of the new depreciation rates effective February 2009. Approval by the Virginia Commission does not preclude the rates from being raised as an issue by any party in KU's current base rate case in Virginia.

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 financial or other impact as a result of this Order. In April 2009, KU filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, that suspends for five months all net metering tariffs filed by the jurisdictional electric utilities. This suspension is intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held a telephonic informal conference with the parties to discuss issues related to the net metering tariffs filed by KU. Following this conference, the intervenors and KU have resolved all issues and KU has filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

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. The Kentucky Commission has established a procedural schedule that allows for data discovery and testimony through July 2009. A public hearing has not been scheduled in this matter. [monitor updates]

Integrated Resource Plan. Pursuant to the Virginia Commission's December 2008 Order, KU filed its Integrated Resource Plan ("IRP") in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. The Virginia Commission has not established a procedural schedule for this proceeding.

Note 3 - Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of September 30 follow:

	September 30, 2009		December 31, 2008	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $228 million as of September 30, 2009 and December 31, 2008)	$ 351	$ 353	$ 351	$ 349
Long-term debt from affiliate	$ 1,281	$ 1,409	$ 1,181	$ 1,117

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 values 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 September 30, 2009, 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 September 30, 2008 and 2009, KU had no interest rate swaps outstanding.

KU is subject to interest rate and commodity price risk related to on-going business operations. KU currently manages these risks using derivative financial instruments including swaps and forward contracts.

KU 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 the Fair Value Measurements and Disclosures topic of the FASB ASC, as follows:

- 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.

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 the Derivatives and Hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades on the Intercontinental Exchange. 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 measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. 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 2009 or 2008. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. KU uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At September 30, 2009, 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 September 30, 2009, no credit reserve related to the energy trading and risk management contracts was required. At December 31, 2008, counterparty credit reserves were less than $1 million.

The volume of electricity based financial derivatives outstanding at September 30, 2009 and December 31, 2008, was 457,600 Mwhs and 146,000 Mwhs, respectively. Of the volume outstanding at September 30, 2009, 68,800 Mwhs will settle in 2009 and 388,800 Mwhs will settle in 2010. As of September 30, 2009, estimated peak wholesale sales are hedged 100% for both 2009 and 2010. Off-peak and weekend wholesale positions are unhedged.

The following tables set forth by level within the fair value hierarchy, KU's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009 and December 31, 2008. No cash collateral related to the energy trading and risk management contracts was required at September 30, 2009. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2008. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable and is a level 1 measurement based on the funds being held in liquid accounts. Energy trading and risk management contracts are considered level 2 based on measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. Liabilities arising from energy trading and risk management contracts accounted for at fair value at December 31, 2008 total less than $1 million and use level 2 measurements. There are no level 3 measurements for the periods ending September 30, 2009 and December 31, 2008.

September 30, 2009 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
Financial Liabilities:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Total Financial Liabilities	$ -	$ 1	$ 1

December 31, 2008 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

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. The aggregate mark-to-market value of all energy trading and risk management contracts with credit risk related contingent features that are in a liability position on September 30, 2009 is $1 million, with no collateral posted in the normal course of business. At September 30, 2009, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required as a result of these contracts.

The table below shows the fair value and balance sheet location of derivatives not designated as hedging instruments as of September 30, 2009:

(in millions)	Asset Derivatives Balance Sheet Location	Asset Derivatives Fair Value	Liability Derivatives Balance Sheet Location	Liability Derivatives Fair Value
Energy trading and risk management contracts (current)	Other current assets	$ 1	Other current liabilities	$ 1
Total		$ 1		$ 1

At September 30, 2009, the fair value of long-term liabilities for energy trading and risk management contracts not designated as hedging instruments was 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.

The following table presents the effect of derivatives not designated as hedging instruments on income for the three months and nine months ended September 30, 2009:

(in millions)	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives: Three Months Ended September 30, 2009	Amount of Gain (Loss) Recognized in Income on Derivatives: Nine Months Ended September 30, 2009
Energy trading and risk management contracts (unrealized)	Other income (expense) - net	$ (3)	$ (1)
Total		$ (3)	$ (1)

Net realized gains and losses were less than $1 million in the three and nine month periods ended September 30, 2009 and September 30, 2008. Net unrealized gains and losses were $1 million for the three and nine months ended September 30, 2009.

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 for the three and nine months ended September 30. The tables include the costs associated with both KU employees and E.ON U.S. Services employees who are providing services to the Company. The E.ON U.S. Services costs that are allocated to KU are approximately 51% and 46% of E.ON U.S. Services costs for September 30, 2009 and 2008, respectively.

(in millions)	Pension Benefits Three Months Ended September 30, 2009			2008		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 2	$ 1	$ 3	$ 1	$ 1	$ 2
Interest cost	4	2	6	4	1	5
Expected return on plan assets	(3)	(1)	(4)	(4)	(1)	(5)
Amortization of actuarial loss	2	1	3	-	-	-
Benefit cost	$ 5	$ 3	$ 8	$ 1	$ 1	$ 2

(in millions)	Other Postretirement Benefits Three Months Ended September 30, 2009			2008		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Interest cost	$ 1	$ -	$ 1	$ 1	$ -	$ 1
Benefit cost	$ 1	$ -	$ 1	$ 1	$ -	$ 1

(in millions)	Pension Benefits Nine Months Ended September 30, 2009			2008		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 4	$ 4	$ 8	$ 4	$ 3	$ 7
Interest cost	13	5	18	13	4	17
Expected return on plan assets	(10)	(4)	(14)	(15)	(4)	(19)
Amortization of prior service costs	1	1	2	1	1	2
Amortization of actuarial loss	6	2	8	-	-	-
Benefit cost	$ 14	$ 8	$ 22	$ 3	$ 4	$ 7

(in millions)	Other Postretirement Benefits Nine Months Ended September 30, 2009			2008		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	3	-	3	3	-	3
Expected return on plan assets	-	-	-	(1)	-	(1)
Amortization of transitional obligation	1	-	1	1	-	1
Benefit cost	$ 5	$ 1	$ 6	$ 4	$ 1	$ 5

In 2009, KU has made contributions to other postretirement benefit plans totaling $4 million. In April 2009, KU made a contribution to a pension plan covering its employees of $13 million. In addition, E.ON U.S. Services made a pension plan contribution of $8 million. KU's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006. KU also anticipates making further 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.

In August 2009, KU and its employees represented by the International Brotherhood of Electrical Workers Local 2100 entered into a new 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.

Note 5 - 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. The Company 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.

Additions and reductions of uncertain tax positions during 2009 and 2008 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.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of September 30, 2009 and December 31, 2008. The interest expense and 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 through September 30, 2009.

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 $6 million and $9 million during the three months ended September 30, 2009 and 2008, respectively, and $17 million and $22 million during the nine months ended September 30, 2009 and 2008, 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, in January and April 2009, additional motions were filed for consideration for which pleadings are still before the Court. The Company 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 $228 million of pollution control bonds that are 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 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. The average annualized interest rate for these bonds during the nine months ended September 30, 2009 was 0.65%.

Pollution control 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. 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 September 30, 2009, KU had no bond proceeds in trust included in restricted cash on the balance sheet. At December 31, 2008, KU had $9 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 reduced due to exposures relating to insurance of sub-prime mortgages. At September 30, 2009, 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. During 2008, interest rates increased, and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During the nine months ended September 30, 2009 and 2008, the average rate on the auction rate bonds was 0.51% and 4.72%, 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 June 2009, S&P downgraded the credit rating of Ambac from "A" to "BBB". As a result, S&P downgraded the rating on the Carroll County 2002 Series C bond from "A" to "BBB+" in June 2009. The S&P rating of this bond is now based on the rating of the Company rather than the rating of Ambac since the Company's rating is higher.

During 2008, KU converted several series of its pollution control bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with these conversions, KU purchased some of the bonds from the remarketing agent. The bonds that were repurchased from the remarketing agent in 2008 were either defeased or remarketed during 2008.

As of September 30, 2009, KU had no remaining repurchased bonds. During 2008, KU refinanced and remarketed $63 million and refinanced $17 million of pollution control bonds that had been previously repurchased by the Company.

In April 2009, KU borrowed $50 million from Fidelia for a term of 8 years at a fixed rate of 5.28%. In July 2009, KU borrowed an additional $50 million from Fidelia for a period of ten years at a fixed rate of 4.81%. The loans are unsecured.

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
September 30, 2009	$ 400	$ 23	$ 377	0.25%
December 31, 2008	$ 400	$ 16	$ 384	1.49%

E.ON U.S. maintains revolving credit facilities totaling $313 million at September 30, 2009 and December 31, 2008, to ensure funding availability for the money pool. At September 30, 2009, 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 balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2009	$ 313	$ 246	$ 67	1.66%
December 31, 2008	$ 313	$ 299	$ 14	2.05%

As of September 30, 2009, KU maintained a bilateral line of credit, with an unaffiliated financial institution, totaling $35 million which matures in June 2012. At September 30, 2009, there was no balance outstanding under this facility. The Company also maintains letter of credit facilities that support $195 million of the $228 million of bonds that can be put back to the Company. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment.

There were no redemptions or issuances of long-term debt with non-affiliated companies year-to-date through September 30, 2009.

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, 2008 (including, but not limited to Notes 2, 9 and 12 to the financial statements of KU contained therein). See 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 which was 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 involved 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. In July 2005, the court issued a summary judgment ruling upholding OMU's contractual right to terminate the OMU agreement in May 2010.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in KU's favor. 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, plus pre- and post-judgment interest, and (ii) denying KU's claim for damages based upon sub-par operations and availability of the OMU units. In April 2009, the court issued a ruling on various post-trial motions denying certain challenges to calculation elements of the $9 million award or of interest amounts associated therewith. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with the court's prior rulings and KU has received the agreed settlement amounts.

Construction Program. KU had $61 million of commitments in connection with its construction program at September 30, 2009.

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. In March 2009, the parties completed an agreement resolving certain 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 is estimated to be approximately $30 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 object to the state air permit and in April 2008, they filed a petition seeking an EPA objection to 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. As part of a routine permit renewal, the KDAQ revised the permit to address the issues identified in the EPA's Order. In June 2009, the EPA objected to the permit renewal on the grounds that it failed to include a case by case Maximum Achievable Control Technology analysis and required additional changes to language addressing startup and shutdown operations. In August 2009, the EPA issued an order relating to all existing current issues in the TC2 air permit proceeding. The

EPA supported the Company's positions on all but two issues. The permit was remanded to the KDAQ to correct deficiencies concerning matters relating to an auxiliary boiler and the appropriate particulate standard to apply. The Company generally believes both of these matters should not have a material adverse effect on its financial condition or results of operations. The Company is currently analyzing the order and possible future actions and cannot predict the final outcome of this proceeding. [update]

Reserve Sharing Developments. KU and LG&E are currently members of the Midwest Contingency Reserve Sharing Group which will terminate on December 31, 2009. KU and LG&E are finalizing alternative arrangements for sharing contingency reserve which involves the formation and participation in a new reserve sharing group. Contingency reserves, including spinning reserves and supplemental reserves, relate to power or capacity requirements the Companies must have available for certain reliability purposes. The determination of whether to self supply or contract for such reserve sharing with other parties has certain operational or financial impacts. The Companies believe it is very likely that the new group will start operations on January 1, 2010. [monitor updates]

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 place 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 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 Clean Air Visibility Rule 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 through 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 $705 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. As discussed below, 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 and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. If enacted into law, the bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020, and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency. Senate action on similar legislation is not expected until later this year. [update]

Separately, at the administrative level, in April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding could potentially result in EPA regulations governing GHG emissions from motor vehicles, power plants and other sources.

KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. 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. While the Company believes that many costs of complying with mandatory GHG reduction requirements or purchasing emission allowances to meet applicable requirements would likely be recoverable, in whole or in part under the ECR, where such costs are related to the Company's coal-fired generating assets, or other potential cost-recovery mechanisms, this cannot be assured.

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 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 entered the consent decree which is now legally in effect.

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. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV. In March 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.

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 a proposed settlement with state regulators regarding particulate limits in the air permit for KU's Tyrone generating station, remediation activities for elevated polychlorinated biphenyl 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 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 FERC regulations under the Public Utility Holding Company Act of 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's intercompany electric revenues and purchased power expense were as follows:

(in millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Electric operating revenues from LG&E	$ 1	$ 15	$ 15	$ 44
Purchased power from LG&E	21	21	79	73

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, 2009	2008	Nine Months Ended September 30, 2009	2008
Interest on money pool loans	$ -	$ 1	$ -	$ 1
Interest on Fidelia loans	18	14	51	40

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 and hourly 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 were as follows:

(in millions)	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
E.ON U.S. Services billings to KU	$ 43	$ 62	$ 121	$ 173
KU billings to LG&E	16	21	63	58
LG&E billings to KU	-	-	-	5
KU billings to E.ON U.S. Services	3	-	5	2

In March and June 2009, KU received capital contributions of $50 million and $25 million, respectively from its common shareholder, E.ON U.S.

Note 9 – Subsequent Events

Subsequent events have been evaluated through November 12, 2009, the date of issuance of these statements and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

Management's Discussion and Analysis

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, 2009, 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, 2008.

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. KU provides electric service to approximately 512,000 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 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. KU's affiliate, LG&E, 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 in Kentucky.

Regulatory Matters

In January 2009, KU, the AG, KIUC and all other parties to the base rate case filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, KU's base rates will decrease $9 million annually. An Order approving the settlement was received in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, which will result in increased revenues of approximately $16 million annually.

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 $64 million of operation and maintenance expenses and $34 million of capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 winter storms.

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.

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. Recent developments indicate an increased possibility of significant climate-change or greenhouse gas legislation or regulation, particularly at the federal level. While the final terms and impacts of such initiatives cannot be estimated, as a primarily coal-fueled utility, KU could be highly affected by such proceedings. Ultimately, environmental matters or potential environmental matters can represent an important element of current or future capital requirements, operating and maintenance expenses or compliance risks for the Company. 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, 2009, Compared to Three Months Ended September 30, 2008

Net Income

Net income for the three months ended September 30, 2009, increased $23 million compared to the same period in 2008. The increase was primarily the result of decreased operating expense ($87 million), partially offset by decreased electric revenues ($27 million), decreased other income - net ($15 million), increased income tax expense ($20 million) and increased interest expense, including interest expense to affiliated companies ($2 million).

Revenues

Revenues decreased $27 million in the three months ended September 30, 2009, primarily due to:

- Decreased wholesale sales ($19 million) due to lower sales volumes to LG&E ($14 million) and third-parties ($5 million) as a result of lower economic capacity caused by low spot market pricing in the third quarter of 2009. Via a mutual agreement, KU sells its higher cost electricity to LG&E for LG&E's wholesale sales and KU purchases LG&E's lower cost electricity to serve KU's native load.
- Decreased fuel costs billed to customers through the FAC ($15 million) due to lower fuel prices
- Decreased retail sales volumes delivered ($11 million) due to weakened economic conditions and mild weather
- Decreased base rates ($3 million) due to the application of the Kentucky base rate case settlement in February 2009
- Increased ECR surcharge ($10 million) due to increased recoverable capital spending
- Increased DSM revenue ($5 million) due to increased recoverable program spending
- Increased miscellaneous revenues ($3 million) due to the initial assessment of late payment fees in the second quarter of 2009
- Decreased merger surcredit ($2 million) due to the surcredit termination in February 2009

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 decreased $33 million in the three months ended September 30, 2009, primarily due to:

- Decreased volumes of fuel usage ($32 million) due to decreased native load and wholesale sales
- Decreased commodity and transportation costs for coal and natural gas ($1 million)

Power purchased expense decreased $8 million in the three months ended September 30, 2009, primarily due to:

- Decreased prices for purchases used to serve retail customers ($7 million) due to lower native load demand
- Decreased third-party purchased volumes for native load ($2 million) as a result of lower economic capacity caused by low spot market pricing during the majority of the third quarter of 2009
- Increased prices for purchases from LG&E ($1 million) due to native load demand payments on long term contracts

Other operation and maintenance expense decreased $44 million in the three months ended September 30, 2009, due to decreased maintenance expense ($54 million) and offset by increased other operation expense ($10 million).

Maintenance expense decreased $54 million in the three months ended September 30, 2009, primarily due to the reclassification of 2009 wind and ice storm restoration expenses to a regulatory asset.

Other operation expense increased $10 million in the three months ended September 30, 2009, primarily due to:

- Increased administrative and general expense ($9 million) due to timing of DSM expenditures and increased labor costs
- Increased pension expense ($4 million) due to lower 2008 pension asset investment performance
- Increased steam expense ($1 million) due to utilization of SCRs year-round
- Decreased distribution expense ($4 million) due to the reclassification of 2009 wind and ice storm restoration expenses to a regulatory asset

Other income – net decreased $15 million in the three months ended September 30, 2009, primarily due to:

- Decreased $11 million due to lower subsidiary equity earnings from Electric Energy, Inc.
- Decreased $3 million due to the change in the mark-to-market power purchase swaps resulting from price increases in 2009 and price decreases in 2008
- Decreased $1 million due to discontinuance of Allowance for Funds Used During Construction (AFUDC) on ECR projects as a result of the FERC rate case

Interest expense, including interest expense to affiliated companies, increased $2 million in the three months ended September 30, 2009, primarily due to interest on increased borrowings with affiliated companies ($3 million) offset by decreased interest on bonds ($1 million) due to lower interest rates.

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

	Three Months Ended September 30,	
	2009	2008
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	3.5	2.6
Dividends received deduction related to Electric Energy Inc. investment	-	(3.4)
Qualified production activities deduction	-	(1.2)
Amortization of investment tax credits	-	(0.1)
Nondeductible life insurance	(0.2)	(0.3)
Excess deferred taxes on depreciation	(0.7)	(0.5)
Other differences	(0.5)	(1.4)
Effective income tax rate	37.1 %	30.7 %

The effective income tax rate increased for the three months ended September 30, 2009, compared to the three months ended September 30, 2008, primarily due to no dividends received deduction, related to zero dividends received from Electric Energy Inc., in the third quarter of 2009.

Nine Months Ended September 30, 2009 Compared to
Nine Months Ended September 30, 2008

Net Income

Net income for the nine months ended September 30, 2009, decreased $18 million compared to the same period in 2008. The decrease was primarily the result of decreased electric revenue ($29 million), decreased other income – net ($25 million), increased interest expense, including interest expense to affiliated companies ($5 million), partially offset by decreased operating expense ($39 million) and decreased income taxes ($2 million).

Revenues

Revenues decreased $29 million in the nine months ended September 30, 2009, primarily due to:

- Decreased wholesale sales ($39 million) due to lower sales volumes to LG&E ($30 million) and third-parties ($10 million) as a result of scheduled coal-fired generation unit outages during January through April 2009, and lower economic capacity caused by low spot market pricing during the majority of 2009. Via a mutual agreement, KU sells its higher cost electricity to LG&E for LG&E's wholesale sales and KU purchases LG&E's lower cost electricity to serve KU's native load.
- Decreased retail sales volumes delivered ($39 million) due to milder weather, weakened economic conditions and significant 2009 storm outages
- Decreased base rates ($5 million) due to the application of the Kentucky base rate settlement in February 2009, partially offset by the increase in Virginia levelized fuel factor
- Decreased fuel costs billed to customers through the FAC ($2 million) due to a refund of purchased power costs from OMU, partially offset by increased fuel prices

- Increased ECR surcharge ($36x million) due to increased recoverable capital spending
- Decreased merger surcredit ($10 million) due to a lower rate approved by the Kentucky Commission in June 2008 and the surcredit termination in February 2009
- Increased miscellaneous revenue ($5 million) resulting from the initial assessment of late payment fees in the second quarter of 2009
- Increased DSM revenue ($3 million) due to increased recoverable program spending
- Decreased VDT surcredit ($2 million) due to termination in August 2008

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 decreased $51 million in the nine months ended September 30, 2009, primarily due to:

- Decreased volumes of fuel usage ($72 million) due to decreased native load and wholesale sales
- Increased commodity and transportation costs for coal and natural gas ($21 million)

Power purchased expense decreased $10 million in the nine months ended September 30, 2009, primarily due to:

- Decreased prices for purchases used to serve retail customers ($17x million) due to increased availability of power from OMU and lower spot market pricing in 2009
- Decreased power purchased expense ($7 million) due to a refund of power purchased costs related to the OMU settlement
- Decreased third-party purchased volumes for off-system sales ($1 million) as a result of low spot market pricing
- Increased third-party purchased volumes for native load ($5 million) as a result of scheduled coal-fired generation unit outages and lower economic capacity caused by low spot market pricing for the majority of 2009
- Increased purchased volumes from LG&E ($10 million) and offset by lower prices ($4 million). Via a mutual agreement, KU purchases LG&E's lower cost electricity to serve KU's native load. LG&E was able to provide higher volumes due to LG&E's reduced native load requirements as a result of milder weather and the weakened economy.
- Increased prices for purchases from LG&E ($3 million) due to native load demand payments on long term contracts

Other operation and maintenance expense increased $22 million in the nine months ended September 30, 2009, due to increased other operation expense ($20 million) and increased maintenance expense ($2 million).

Other operation expense increased $20 million in the nine months ended September 30, 2009, primarily due to:

- Increased pension expense ($14 million) due to lower 2008 pension asset investment performance
- Increased steam expense ($4 million) due to utilization of SCRs year-round
- Increased administrative and general expense ($3 million) due to consulting fees for software training and increased labor costs

- Increased property tax ($1 million) due to higher tax assessment resulting from construction expenditures
- Decreased generation expense ($2 million) due to scheduled unit outages and routine maintenance

Maintenance expense increased $2 million in the nine months ended September 30, 2009, primarily due to:

- Increased steam expense ($4 million) due to increased scope of work for scheduled outages
- Increased transmission expense ($1 million) primarily due to the 2009 winter storm restoration
- Increased administrative and general expense ($1 million) due to increased labor and system maintenance contracts resulting from completion of a significant in-house customer information system project
- Decreased distribution expense ($4 million) as a result of 2008 wind storm restoration not reclassified to regulatory assets until fourth quarter 2008

Other income – net decreased $25 million in the nine months ended September 30, 2009, primarily due to lower subsidiary equity earnings from Electric Energy, Inc.

Interest expense, including interest expense to affiliated companies, increased $5 million in the nine months ended September 30, 2009, primarily due to increased borrowings with affiliated companies ($10 million) offset by decreased interest on bonds ($5 million) due to lower interest rates.

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

	Nine Months Ended September 30,	
	2009	2008
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	2.7	2.4
Dividends received deduction related to Electric Energy Inc. investment	(2.1)	(3.8)
Qualified production activities deduction	(0.3)	(1.3)
Amortization of investment tax credits	(0.1)	(0.1)
Nondeductible life insurance	(0.3)	(0.3)
Excess deferred taxes on depreciation	(1.0)	(0.8)
Other differences	(0.8)	(0.7)
Effective income tax rate	33.1 %	30.4 %

The effective income tax rate increased for the nine months ended September 30, 2009, compared to the nine months ended September 30, 2008, due to a decrease in the dividends received deduction, related to a decrease in dividends received from Electric Energy Inc., through the third quarter 2009.

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 September 30, 2009, KU had a working capital deficiency of $164 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 6 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

The $53 million decrease in net cash provided by operating activities for the nine months ended September 30, 2009 compared to September 30, 2008, was primarily the result of changes in:

- Storm restoration regulatory asset ($57 million) due to the establishment of a regulatory asset for the 2009 winter storm expenses
- Accounts payable ($27 million) primarily due to payments relating to 2009 winter storm restoration, timing of other payments and lower accruals
- Pension and postretirement funding ($15 million) due to valuation related to market conditions
- Other ($11 million)
- Accrued income taxes ($8 million)
- Materials and supplies ($2 million) primarily due to increased fuel inventory
- Environmental cost recovery receivable ($1 million)

These decreases were partially offset by changes in:

- Earnings, net of non-cash items ($54 million)
- Accounts receivable ($11 million) primarily due to timing on collection of accounts
- Fuel adjustment clause receivable, net ($2 million)
- Other current liabilities ($1 million)

Investing Activities

Net cash used for investing activities decreased $185 million in the nine months ended September 30, 2009, compared to 2008. The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $378 million and $554 million in the nine months ended September 30, 2009 and 2008, respectively, a net decrease of $176 million. The remaining decrease in net cash used for investing activities is due to a decrease in assets transferred from LG&E for TC2 of $10 million, partially offset by decreased funds received from restricted cash of $1 million representing escrow proceeds from the pollution control bonds.

Financing Activities

Net cash inflows from financing activities were $181 million and $313 million in the nine months ended September 30, 2009 and 2008, respectively, resulting in a decrease in net cash provided by financing activities of $132 million. The decrease in financing inflows is due to decreased equity contributions from E.ON U.S. of $50 million, decreased long-term borrowings from affiliates of $75 million and decreased short-term borrowings net of repayments from an affiliated company of $87 million, partially offset by decreased reacquisition of bonds of $80 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, 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.

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. Credit market conditions can affect aspects of the availability, terms or methods in which the Company funds its capital 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 the Company at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Notes 6 and 9 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 September 30, 2009, KU has borrowed $23 million of this authorized amount. See Note 6 of Notes to Financial Statements.

KU's debt ratings as of September 30, 2009, 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 6 of Notes to Financial Statements for a discussion of 2008 and 2009 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

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. Effective April 1, 2009, the Company initiated a new software and data system for customer accounts and associated billing, management, operations and record-keeping aspects thereof, following a comprehensive planning, testing and implementation project. There were no changes to the Company's internal controls as a result of the new software implementation. There have been no changes in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2009, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2008 KU Annual Report.

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, 2008: 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 for the year ended December 31, 2008 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, the Company 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.

Document Revisions
Total Revisions: 8

Author: Don Harris
Date: 10/20/2009 2:36:00 PM
Type: Insert
Range: formal

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Date: 10/20/2009 2:36:00 PM
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Author: Don Harris
Date: 10/20/2009 2:37:00 PM
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Range: [10/13 public hearing]

Author: Don Harris
Date: 10/20/2009 2:48:00 PM
Type: Insert
Range: On September 3, 2009, KU filed an application with the KPSC concerning the need to obtain a CPCN for the construction of temporary transmission facilities in Hardin County, KY. An informal conference took place on October 13, 2009 at the KPSC offices. Data discovery continues through November 2009. The KPSC must issue a decision by January 1, 2010.

Author: Don Harris
Date: 10/20/2009 3:51:00 PM
Type: Delete
Range: [update for September filings/CCN Order]

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1								Pension Benefits		
2	(in millions)					Three Months Ended September 3(				
3					2009					
4										
5										
6							Total			
7			KU		E.ON U.S. Services Allocation to KU		KU		KU	
8	Service cost		$ 2		$ 1		$ 3		$ 1	
9	Interest cost		4		2		6		4	
10	Expected return on plan									
11	assets		(3)		(1)		(4)		(4)	
12	Amortization of prior									
13	service costs						-			
14	Amortization of actuarial									
15	loss		2		1		3		-	
16	Benefit cost		$ 5		$ 3		$ 8		$ 1	
17										
18										
19										
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22										
23										
24										
25										
26										
27										
28										
29										

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1			
2	),		
3	2008		
4			
5			
6			Total
7	E.ON U.S. Services Allocation to KU		KU
8	$ 1		$ 2
9	1		5
10			
11	(1)		(5)
12			
13			-
14			
15	-		-
16	$ 1		$ 2
17			
18			
19			
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27			
28			
29			

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1										
2										
3										
4										
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11										
12										
13										
14										
15										
16										
17										
18							Other Postretirement Benefits			
19	(in millions)						Three Months Ended September 3(			
20					2009					
21										
22										
23							Total			
24			KU		E.ON U.S. Services Allocation to KU		KU		KU	
25	Service cost		$ -		$ -		$ -		$ -	
26	Interest cost		$ 1		$ -		$ 1		$ 1	
27	Expected return on plan									
28	assets		-		-		-		-	
29	Amortization of									
30	transitional obligation		-		-		-		-	

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18			
19	),		
20	2008		
21			
22			
23			Total
24	E.ON U.S. Services Allocation to KU		KU
25	$ -		$ -
26	$ -		$ 1
27			
28	-		-
29			
30	-		-

	A	B	C	D	E	F	G	H	I	J
31	Benefit cost		$ 1		$ -		$ 1		$ 1	

	K	L	M
31	$ -		$ 1

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	Pension Benefits			
(in millions)	Nine Months Ended September 30,			
	2009			
			Total	
	KU	E.ON U.S. Services Allocation to KU	KU	KU
Service cost	$ 4	$ 4	$ 8	$ 4
Interest cost	13	5	18	13
Expected return on plan assets	(10)	(4)	(14)	(15)
Amortization of prior service costs	1	1	2	1
Amortization of actuarial loss	6	2	8	-
Benefit cost	$ 14	$ 8	$ 22	$ 3

	K	L	M
1			
2			
3	2008		
4			
5			
6			Total
7	E.ON U.S. Services Allocation to KU		KU
8	$ 3		$ 7
9	4		17
10			
11	(4)		(19)
12			
13	1		2
14			
15	-		-
16	$ 4		$ 7
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
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7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
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15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1										
2										
3										
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8										
9										
10										
11										
12										
13										
14										
15										
16										
17			Other Postretirement Benefits							
18	(in millions)		Nine Months Ended September 30							
19			2009							
20										
21										
22							Total			
23			KU		E.ON U.S. Services Allocation to KU		KU		KU	
24	Service cost		$ 1		$ 1		$ 2		$ 1	
25	Interest cost		3		-		3		3	
26	Expected return on plan									
27	assets		-		-		-		(1)	
28	Amortization of									
29	transitional obligation		1		-		1		1	
30	Benefit cost		$ 5		$ 1		$ 6		$ 4	

	K	L	M
1			
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10			
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12			
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14			
15			
16			
17			
18	,		
19	2008		
20			
21			
22			Total
23	E.ON U.S. Services Allocation to KU		KU
24	$ 1		$ 2
25	-		3
26			
27	-		(1)
28			
29	-		1
30	$ 1		$ 5

Louisville Gas and Electric Company

Financial Statements and Additional Information

(Unaudited)

As of September 30, 2009 and December 31, 2008
and for the three-month and nine-month periods ended
September 30, 2009 and 2008

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
APB	Accounting Principles Board
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury 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
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. Services Inc.
EPA	U.S. Environmental Protection Agency
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.
FSP	FASB Staff Position
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
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
Mcf	Thousand Cubic Feet
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
OCI	Other Comprehensive Income
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Ratings Services
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 Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
OPERATING REVENUES				
Electric (Note 9)	$ 250	$ 283	$ 712	$ 747
Gas	28	47	270	295
Total operating revenues	278	330	982	1,042
OPERATING EXPENSES				
Fuel for electric generation	83	96	256	257
Power purchased (Note 9)	10	27	43	75
Gas supply expenses	10	32	189	224
Other operation and maintenance expenses (Note 2)	44	90	252	247
Depreciation and amortization	35	32	102	95
Total operating expenses	182	277	842	898
Operating income	96	53	140	144
Other expense (income) – net (Note 3)	5	(5)	(13)	(1)
Interest expense (Notes 3 and 6)	5	4	16	19
Interest expense to affiliated companies (Notes 6 and 9)	7	8	20	20
Income before income taxes	79	46	117	106
Federal and state income tax expense (Note 5)	29	13	41	33
Net income	$ 50	$ 33	$ 76	$ 73

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Balance at beginning of period	$ 686	$ 690	$ 740	$ 690
Net income	50	33	76	73
Cash dividends declared on common stock (Note 9)	-	-	80	40
Balance at end of period	$ 736	$ 723	$ 736	$ 723

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

Louisville Gas and Electric Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	September 30, 2009	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 6	$ 4
Restricted cash	1	2
Accounts receivable, net:		
Customer – less reserves of $5 million and $1 million as of September 30, 2009 and December 31, 2008, respectively	105	180
Other – less reserves of $1 million as of September 30, 2009 and December 31, 2008	12	23
Materials and supplies:		
Fuel (predominantly coal)	57	51
Gas stored underground	60	112
Other materials and supplies	33	32
Regulatory assets (Note 2)	13	43
Prepayments and other current assets	6	7
Total current assets	293	454
Utility plant:		
At original cost	4,262	4,132
Less: reserve for depreciation	1,740	1,690
Total utility plant, net	2,522	2,442
Construction work in progress	333	374
Total utility plant and construction work in progress	2,855	2,816
Deferred debits and other assets:		
Collateral deposit (Note 3)	16	22
Regulatory assets (Note 2):		
Pension and postretirement benefits	250	250
Other	126	89
Other assets	4	6
Total deferred debits and other assets	396	367
Total assets	$ 3,544	$ 3,637

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, 2009	December 31, 2008
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 120	$ 120
Notes payable to affiliated companies (Notes 6 and 9)	149	222
Accounts payable	60	95
Accounts payable to affiliated companies (Note 9)	27	38
Deferred income taxes – net (Note 5)	21	10
Customer deposits	23	22
Regulatory liabilities (Note 2)	47	35
Other current liabilities	41	48
Total current liabilities	488	590
Long-term debt:		
Long-term bonds (Note 6)	291	291
Long-term debt to affiliated company (Notes 6 and 9)	485	485
Total long-term debt	776	776
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	359	342
Accumulated provision for pensions and related benefits (Note 4)	237	225
Investment tax credit (Note 5)	51	50
Asset retirement obligations	31	31
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	258	251
Deferred income taxes – net	42	45
Other	6	11
Derivative liability (Note 3)	38	55
Other liabilities	26	27
Total deferred credits and other liabilities	1,048	1,037
Common equity:		
Common stock, without par value - Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	84	84
Accumulated other comprehensive loss	(12)	(14)
Retained earnings (Note 9)	736	740
Total common equity	1,232	1,234
Total liabilities and equity	$ 3,544	$ 3,637

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

LGE-KU-1006713

Louisville Gas and Electric Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 76	$ 73
Items not requiring cash currently:		
Depreciation and amortization	102	95
Deferred income taxes – net	29	11
Provision for pension and postretirement plans	25	10
Gain from disposal of asset	-	(9)
Derivative liability	(14)	5
Changes in current assets and liabilities:		
Accounts receivable	87	21
Materials and supplies	45	(36)
Accounts payable	(55)	(3)
Accrued income taxes	(7)	7
Other current assets and liabilities	10	6
Long-term derivative liability	(4)	(3)
Collateral deposit – interest rate swap (Note 3)	6	(1)
Pension and postretirement funding (Note 4)	(13)	(4)
Storm restoration regulatory asset	(44)	-
Gas supply clause, net	31	(13)
Fuel adjustment clause	9	2
Other	(1)	7
Net cash provided by operating activities	282	168
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(127)	(179)
Assets transferred to affiliate	-	10
Proceeds from sale of asset	-	9
Net cash used for investing activities	(127)	(160)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings from affiliated company (Note 6)	-	25
Short-term borrowings from affiliated company – net (Note 6)	(73)	266
Reacquired bonds (Note 6)	-	(259)
Payment of dividends (Note 9)	(80)	(40)
Net cash used for financing activities	(153)	(8)
CHANGE IN CASH AND CASH EQUIVALENTS	2	-
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4	4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6	$ 4

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, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net income	$ 50	$ 33	$ 76	$ 73
Gain (loss) on derivative instruments and hedging activities - net of tax (expense) benefit of $1 million, less than $(1) million, $(1) million and $(1) million, respectively (Note 3)	(2)	-	2	2
Comprehensive income	$ 48	$ 33	$ 78	$ 75

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

Note 1 - General

The unaudited financial statements include the accounts of LG&E. The Company'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 ("Annual Report") for the year ended December 31, 2008, including the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2009 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

ASU 2009-05

In August 2009, the FASB issued ASU 2009-05, *Fair Value Measurements and Disclosures,* an update to ASC 820, which is effective for the first reporting period beginning after issuance. ASU 2009-05 provides amendments to clarify and reduce ambiguity in valuation techniques, adjustments and measurement criteria for liabilities measured at fair value. The adoption of ASU 2009-05 will have no impact on the Company's results of operations, financial position or liquidity.

SFAS No. 168 (ASC 105-10)

In June 2009, the FASB issued SFAS No. 168 (ASC 105-10), *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles,* which is effective for interim and annual periods ending after September 15, 2009. SFAS No. 168 (ASC 105-10) establishes the FASB Accounting Standards Codification ("Codification") as the single source of authoritative nongovernmental U.S. generally accepted accounting principles ("GAAP"). In addition, SFAS No. 168 (ASC 105-10) replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which developed the Codification and identified the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP in the United States. SFAS No. 168 (ASC 105-10) will have no effect on the Company's results of operations, financial position or liquidity, however, references to authoritative accounting literature have changed with the adoption.

SFAS No. 165 (ASC 855-10)

In May 2009, the FASB issued SFAS No. 165 (ASC 855-10), *Subsequent Events,* which is effective for interim and annual periods ending after June 15, 2009. SFAS No. 165 (ASC 855-10) requires disclosure of the date through which subsequent events have been evaluated, as well as whether that date is the date the financial statements were issued or the date they were available to be issued. The adoption of SFAS No. 165 (ASC 855-10) had no impact on the Company's results of operations, financial position or liquidity, however, additional disclosures were required with the adoption.

FSP SFAS 107-1 and APB 28-1 (ASC 825-10)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 (ASC 825-10), *Interim Disclosures about Fair Value of Financial Instruments,* which is effective for interim and annual periods ending after June 15, 2009, and requires qualitative and quantitative disclosures about fair values of assets and liabilities on a quarterly basis. The adoption of FSP SFAS 107-1 and APB 28-1 (ASC 825-10) had no impact on the Company's results of operations, financial position or liquidity, however, additional disclosures were required with the adoption. See Note 3, Financial Instruments, for additional disclosures.

FSP SFAS 132(R)-1 (ASC 715-20)

In December 2008, the FASB issued FSP SFAS 132(R)-1 (ASC 715-20), *Employers' Disclosures about Postretirement Benefit Plan Assets,* which will be effective as of December 31, 2009, and requires additional disclosures related to pension and other postretirement benefit plan assets. Additional disclosures include the investment allocation decision-making process, the fair value of each major category of plan assets as well as the inputs and valuation techniques used to measure fair value and significant concentrations of risk within the plan assets. The adoption of FSP SFAS 132(R)-1 (ASC 715-20) will have no impact on the Company's results of operations, financial position or liquidity, however, additional disclosures will be required with the adoption.

SFAS No. 161 (ASC 815-10)

In March 2008, the FASB issued SFAS No. 161 (ASC 815-10), *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 (ASC 815-10). The adoption of SFAS No. 161 (ASC 815-10) had no impact on LG&E's statements of operations, financial position and cash flows, however, additional disclosures relating to derivatives were required with the adoption effective January 1, 2009.

SFAS No. 160 (ASC 810-10)

In December 2007, the FASB issued SFAS No. 160 (ASC 810-10), *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 adopted SFAS No. 160 (ASC 810-10) effective January 1, 2009, and it had no impact on its statements of operations, financial position and cash flows.

SFAS No. 157 (ASC 820-10)

In September 2006, the FASB issued SFAS No. 157 (ASC 820-10), *Fair Value Measurements*, which, except as described below, was 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 (ASC 820-10) does not expand the application of fair value accounting to new circumstances.

In February 2008, the FASB issued FSP SFAS 157-2 (ASC 820-10), *Effective Date of FASB Statement No. 157,* which delayed the effective date of SFAS No. 157 (ASC 820-10) 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 (ASC 820-10) have been evaluated and have no impact on the Company's financial statements.

The Company adopted SFAS No. 157 (ASC 820-10) effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and it 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 FSP SFAS 157-2 (ASC 820-10), fair value accounting for all nonrecurring fair value measurements of nonfinancial assets and liabilities was adopted effective January 1, 2009, and it had no impact on the statements of operations, financial position and cash flows. At September 30, 2009, no additional disclosures were required per FSP SFAS 157-2 (ASC 820-10) as LG&E did not have any nonfinancial assets or liabilities measured at fair value subsequent to initial measurement. In April 2009, the FASB issued FSP SFAS 157-4 (ASC 820-10), *Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions that are not Orderly,* which is effective for interim and annual periods ending after June 15, 2009. FSP SFAS 157-4 (ASC 820-10) provides additional guidance on determining fair values when there is no active market or where the price inputs being used represent distressed sales. The adoption of FSP SFAS 157-4 (ASC 820-10) had no impact on the Company's financial position, statements of operations and cash flows.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2 of LG&E's Annual Report for the year ended December 31, 2008.

Electric and Gas Rate Cases

In January 2009, LG&E, the AG, KIUC and all other parties to electric and gas base 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 in February

2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, which will result in increased revenues of approximately $21 million annually.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

(in millions)	September 30, 2009	December 31, 2008
Current regulatory assets:		
GSC	$ 3	$ 28
ECR	6	4
FAC	-	7
Net MISO exit	1	-
Other	3	4
Total current regulatory assets	$ 13	$ 43
Non-current other regulatory assets:		
Storm restoration	$ 44	$ -
ARO	21	29
Unamortized loss on bonds	22	23
Net MISO exit	5	12
Hurricane Ike	24	24
Other	10	1
Subtotal non-current other regulatory assets	126	89
Pension and postretirement benefits	250	250
Total non-current regulatory assets	$ 376	$ 339
Current regulatory liabilities:		
GSC	$ 37	$ 30
DSM	8	5
Other	2	-
Total current regulatory liabilities	$ 47	$ 35
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 258	$ 251
Deferred income taxes – net	42	45
Other	6	11
Total non-current regulatory liabilities	$ 306	$ 307

LG&E does not currently earn a rate of return on the ECR, FAC, GSC and gas performance-based ratemaking (included in "GSC" above) regulatory assets 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. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. A return is earned on the unamortized loss on bonds, and these costs are recovered through amortization over the life of the debt. LG&E currently earns a rate of return on the balance of Mill Creek Ash Pond costs included in other regulatory assets, as well as recovery of these costs. The Company will seek recovery of the Storm restoration and Hurricane Ike regulatory assets and CMRG and KCCS contributions, included in other regulatory assets, in the next base rate case. The Company recovers the net MISO exit regulatory asset incurred through April 30, 2008. The Company recovers the remaining regulatory assets, including other regulatory assets comprised of merger surcredit, EKPC FERC transmission settlement agreement and rate case expenses. Other regulatory liabilities include DSM and MISO administrative charges collected via base rates from May 2008 through February 5, 2009. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, per a Kentucky Commission Order, in the next base rate case.

ECR. In August 2009, the Kentucky Commission initiated a two year review of LG&E's environmental surcharge for the period ending April 2009. An order is anticipated in the first quarter of 2010.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. The Company anticipates an order by the end of 2009, and recovery on customer bills through the monthly ECR surcredit beginning February 2010. [update]

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 February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%.

In January 2009, the Kentucky Commission initiated a six-month review of LG&E's environmental surcharge for the period ending October 31, 2008. The Kentucky Commission issued an Order in July 2009, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments for under-recovered costs and the rate of return on capital.

FAC. In August 2009, the Kentucky Commission initiated a routine examination of the FAC for the 6-month period November 1, 2008 through April 30, 2009. A formal hearing was held on October 13, 2009. An Order is anticipated in the fourth quarter of 2009.

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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. The Kentucky Commission issued an Order in June 2009, approving the charges and credits billed through the FAC during the review period.

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.

MISO. In accordance with Kentucky Commission Orders approving the MISO exit, LG&E has established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges 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. Based upon the 2008 FERC Orders, the Company 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. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of $1 million, which the MISO began refunding back to the Company in June 2009, and which were fully collected by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of less than $1 million of expense. Further developments in the RSG proceeding could occur during 2009. Due to the numerous participants, complex principles at issue and changes from prior precedents, the Company cannot predict the ultimate outcome of this matter nor can it predict the impact of the various proposals that have been made by the parties. [update]

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 $47 million of operation and maintenance expenses and $10 million of capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009 winter storms.

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.

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.

Other Regulatory Matters

Wind Power Agreements. In August 2009, LG&E and KU filed a notice of intent with the Kentucky Commission indicating their intention to file an application for approval of a wind purchase power contract and a cost recovery mechanism. The contract was executed in August 2009, and is contingent upon LG&E and KU receiving acceptable regulatory approvals. In September 2009, the Company filed an application and supporting testimony with the Kentucky Commission. [monitor updates]

Trimble County Asset Transfer and Depreciation. LG&E and KU are currently constructing a new base-load, coal fired unit, TC2, which will be jointly owned by LG&E and KU, together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency. In July 2009, LG&E and KU notified the Kentucky Commission of the proposed transfer from LG&E to KU of certain ownership interests in certain existing Trimble County generating station assets which are anticipated to provide joint or common use in support of the TC2 generating unit. The undivided ownership interests being transferred are intended to provide KU an ownership interest in these common assets that is proportional to its interest in TC2. It is anticipated that the assets will be transferred at a price equal to the net book value associated with the proportional interests at the time of the transfer. The assets have a net book value of approximately $50 million as of June 2009. This transfer is expected to be made upon the beginning of TC2 unit testing which is estimated to be December 2009.

In August 2009, in a separate proceeding, LG&E and KU jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable TC2-related generating, pollution control and other plant equipment and assets. The filing requests common depreciation rates for the applicable jointly-owned TC2-related assets, rather than applying differing depreciation rates in place with respect to LG&E's and KU's separately-owned base-load generating assets. In September 2009, data discovery was initiated by the Kentucky Commission and continues through November 2009. A ruling is requested prior to December 2009. [update]

TC2 CCN Application and Transmission Matters. A CCN application for construction of TC2 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. In April 2009, the Kentucky Supreme Court granted a motion for discretionary review filed by LG&E and KU in May 2008. The discretionary review request, which seeks reversal of the appellate court decision and reinstatement of the Circuit Court dismissal of the challenge, may be ruled upon during 2009.

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 the transmission line in some of these forums as well. During 2008, LG&E's affiliate, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation and easement rights. In August 2008, the landowners appealed such rulings to the Kentucky Court of Appeals and received a stay preventing KU from accessing the properties during the appeal. In April 2009, the appellate court denied a KU motion to lift the stay and issued an Order generally (i) retaining the stay until a decision on the merits and (ii) delaying such decision on the merits pending developments in the Supreme Court CCN proceeding mentioned above. After unsuccessfully seeking reconsideration of this ruling by the Court of Appeals and expedited review by the Kentucky Supreme Court in May 2009, KU filed a motion with the Kentucky Supreme Court for discretionary review of the appellate court order affirming the stay in June 2009. That motion is pending.

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.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. 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.

During March 2009, owners of an airfield in Jefferson County, Indiana, filed a petition with the Federal Aviation Administration ("FAA") seeking review of a prior FAA determination regarding certain transmission towers to be constructed at a crossing point of the Ohio River. The FAA previously determined that the towers do not constitute a hazard to air navigation, but such ruling is not deemed final until the review is completed. The receipt of a favorable final FAA determination is necessary for a tall structure permit in Indiana. This matter was resolved favorably through settlement with the owners of the airfield in May 2009.

LG&E and KU are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the transmission line approval, land acquisition and permitting proceedings.

Deleted: [update for September filings/CCN Order]

Depreciation Study. In December 2007, LG&E filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreement in the rate case established new depreciation rates effective February 2009.

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 financial or other impact as a result of this Order. In April 2009, LG&E filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, that suspends for five months all net metering tariffs filed by the jurisdictional electric utilities. This suspension is intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held a telephonic informal conference with the parties to discuss issues related to the net metering tariffs filed by LG&E. Following this conference, the intervenors and LG&E have resolved all issues and LG&E has filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

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. The Kentucky Commission has established a procedural schedule that allows for data discovery and testimony through July 2009. A public hearing has not been scheduled in this matter. [monitor updates]

Note 3 - Financial Instruments

The cost and estimated fair values of LG&E's non-trading financial instruments as of September 30 follow:

	September 30, 2009		December 31, 2008	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $120 million as of September 30, 2009 and December 31, 2008)	$ 411	$ 416	$ 411	$ 392
Long-term debt from affiliate	$ 485	$ 537	$ 485	$ 458
Interest-rate swaps - liability	$ 38	$ 38	$ 55	$ 55

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 values 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 the Fair Value Measurements and Disclosures topic of the FASB ASC. 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 September 30, 2009, 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 $2 million annually.

LG&E is subject to interest rate and commodity price risk related to on-going business operations. LG&E currently manages these risks using derivative financial instruments, including swaps and forward contracts.

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 the Fair Value Measurements and Disclosures topic of the FASB ASC, as follows:

- 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.

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 the type of swaps used by the Company. LG&E considered the impact of counterparty credit risk by evaluating credit ratings and financial information. All counterparties had strong investment grade ratings at September 30, 2009. LG&E did not have any credit exposure to the swap counterparties, as LG&E was in a liability position at September 30, 2009, 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 measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. Cash collateral for interest rate swaps is classified as a collateral deposit which is a long-term asset 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 as of September 30, 2009 and December 31, 2008. 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 0.28% and 1.27% at September 30, 2009 and December 31, 2008, 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 three 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 6, Short-Term and Long-Term Debt.

The interest rate swaps are accounted for on a mark-to-market basis in accordance with the Derivatives and Hedging topic of the FASB ASC. Financial instruments designated as effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and common equity. 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. The table below shows the pre-tax amount and income statement location of gains and losses from interest rate swaps for the three months and nine months ended September 30, 2009:

(in millions)	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives: Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Interest rate swaps – change in the ineffective portion of swaps deemed highly effective	Other income (expense) - net	$ (1)	$ 1
Interest rate swaps – change in the mark-to-market of ineffective swaps	Other income (expense) - net	(3)	14
Total		$ (4)	$ 15

For the nine months ended September 30, 2008, LG&E recorded a pre-tax loss of $1 million in other comprehensive income to reflect the ineffective portion of the hedge. 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 amortized from other comprehensive income to income in the three and nine month periods ended September 30, 2009 was less than $1 million. 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 $16 million, used as collateral for one of the interest rate swaps, is classified as a collateral deposit which is a long-term asset 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 $30 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 the Derivatives and Hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades on the Intercontinental Exchange. 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 measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. 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 2009 or 2008. Changes in market pricing, interest rate and volatility assumptions were made during both years.

LG&E maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, LG&E seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. LG&E uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, LG&E assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At September 30, 2009, 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 September 30, 2009 no credit reserve related to the energy trading and risk management contracts was required. At December 31, 2008, counterparty credit reserves were less than $1 million.

The volume of electricity based financial derivatives outstanding at September 30, 2009 and December 31, 2008, was 457,600 Mwhs and 146,000 Mwhs, respectively. Of the volume outstanding at September 30, 2009, 68,800 Mwhs will settle in 2009 and 388,800 Mwhs will settle in 2010. As of September 30, 2009, estimated peak wholesale sales are hedged 100% for both 2009 and 2010. Off-peak and weekend wholesale positions are unhedged.

The following tables set 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, 2009 and December 31, 2008. Cash collateral related to the energy trading and risk management contracts was $1 million at September 30, 2009, and less than $1 million at December 31, 2008.

Cash collateral is categorized as other accounts receivable and is a level 1 measurement based on the funds being held in liquid accounts. Energy trading and risk management contracts are considered level 2 based on measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. Liabilities arising from energy trading and risk management contracts accounted for at fair value at December 31, 2008 total less than $1 million and use level 2 measurements. There are no level 3 measurements for the periods ending September 30, 2009 and December 31, 2008.

September 30, 2009

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	16	-	16
Total Financial Assets	$ 16	$ 1	$ 17
Financial Liabilities:			
Energy trading and risk management contracts	-	1	-
Interest rate swaps	-	38	38
Total Financial Liabilities	$ -	$ 39	$ 38

December 31, 2008

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

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. The aggregate mark-to-market value of all energy trading and risk management contracts with credit risk related contingent features that are in a liability position on September 30, 2009 $1 million, with no collateral posted in the normal course of business. The aggregate mark-to-market value of all interest rate swaps with credit risk related contingent features that are in a liability position on September 30, 2009, is $26 million for which the Company has posted collateral of $16 million in the normal course of business. If the credit risk related contingent features underlying these agreements were triggered on September 30, 2009, due to a one notch downgrade in the Company's credit rating, the Company would be required to post an additional $5 million of collateral to its counterparties for the interest rate swaps and there would be no effect on the energy trading and risk management contracts or collateral required as a result of these contracts.

The table below shows the fair value and balance sheet location of derivatives designated as hedging instruments as of September 30, 2009:

	Asset Derivatives		Liability Derivatives	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 21
Total		$ -		$ 21

The table below shows the fair value and balance sheet location of derivatives not designated as hedging instruments as of September 30, 2009:

	Asset Derivatives		Liability Derivatives	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 17
Energy trading and risk management contracts (current)	Other current assets	1	Other current liabilities	1
Total		$ 1		$ 18

At September 30, 2009, the fair value of long-term liabilities for energy trading and risk management contracts not designated as hedging instruments was less than $1 million.

The gain (loss) on hedging interest rate swaps recognized in OCI for the three and nine month periods ended September 30, 2009, was $(3) million and $4 million, respectively. For the three and nine month periods ended September 30, 2009, the gain on derivatives reclassified from accumulated OCI to income and the gain on derivatives recognized in income was less than $1 million, and was recorded in interest expense and other (income) expense – net, respectively.

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.

The following table presents the effect of derivatives not designated as hedging instruments on income for the three months and nine months ended September 30, 2009:

(in millions)	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Energy trading and risk management contracts (realized)	Electric revenues	$ 5	$ 8
Interest rate swaps (realized)	Other income (expense) – net	(3)	14
Energy trading and risk management contracts (unrealized)	Other income (expense) – net	(3)	(1)
Total		$ (1)	$ 21

Net unrealized gains were $1 million for the three and nine month periods ended September 30, 2008. Net realized gains and losses were less than $1 million for the three and nine month periods ended September 30, 2008.

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 for the three and nine months ended September 30. The tables include the costs associated with both LG&E employees and E.ON U.S. Services employees who are providing services to the Company. The E.ON U.S. Services costs that are allocated to LG&E are approximately 44% and 42% of E.ON U.S. Services costs for September 30, 2009 and 2008, respectively.

(in millions)	Pension Benefits Three Months Ended September 30, 2009			2008		
	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	7	2	9	7	1	8
Expected return on plan assets	(6)	(1)	(7)	(8)	(1)	(9)
Amortization of prior service costs	1	-	1	1	-	1
Amortization of actuarial loss	3	-	3	-	-	-
Benefit cost	$ 6	$ 2	$ 8	$ 1	$ 1	$ 2

(in millions)	Other Postretirement Benefits Three Months Ended September 30, 2009			2008		
	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Interest cost	$ 1	$ -	$ 1	$ 1	$ -	$ 1
Amortization of prior service costs	1	-	1	1	-	1
Benefit cost	$ 2	$ -	$ 2	$ 2	$ -	$ 2

(in millions)	Pension Benefits Nine Months Ended September 30, 2009			2008		
	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Service cost	$ 3	$ 3	$ 6	$ 3	$ 3	$ 6
Interest cost	19	5	24	19	4	23
Expected return on plan assets	(16)	(4)	(20)	(23)	(4)	(27)
Amortization of prior service costs	4	1	5	4	1	5
Amortization of actuarial loss	9	2	11	1	-	1
Benefit cost	$ 19	$ 7	$ 26	$ 4	$ 4	$ 8

(in millions)	Other Postretirement Benefits Nine Months Ended September 30, 2009			2008		
	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	4	-	4	4	-	4
Amortization of prior service costs	1	-	1	1	-	1
Benefit cost	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

In 2009, LG&E has made contributions to other postretirement benefit plans totaling $5 million. In April 2009, LG&E made a contribution to a pension plan covering its employees of $8 million. In addition, E.ON U.S. Services made a pension plan contribution of $8 million. LG&E's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006. LG&E also anticipates making further 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.

Note 5 - 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. The Company 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, were comprised of $5 million of depreciable temporary differences, and were recorded in the first quarter of 2009. The tax year 2008 return is also being examined under the CAP program.

Additions and reductions of uncertain tax positions during 2009 and 2008 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.

The amount LG&E recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of September 30, 2009 and December 31, 2008. The interest expense and 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 through September 30, 2009.

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 September 30, 2009 and 2008, respectively, and $3 million and $6 million during the nine months ended September 30, 2009 and 2008, 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, in January and April 2009, additional motions were filed for consideration for which pleadings are still before the Court. The Company 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 of pollution control bonds that are 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 2001 Series A and B and Trimble County 2001 Series A and B. Maturity dates for these bonds range from 2026 to 2027. The average annualized interest rate for these bonds during the nine months ended September 30, 2009 was 1.11%.

Pollution control 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. The loan agreement is an unsecured obligation of LG&E.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At September 30, 2009, 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. During 2008, interest rates increased, and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During the nine months ended September 30, 2009 and 2008, the average rate on the auction rate bonds was 0.42% and 4.58%, 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 June 2009, S&P downgraded the credit rating of Ambac from "A" to "BBB". As a result, S&P downgraded the ratings on the Trimble County 2000 Series A, 2002 Series A and 2007 Series A; Jefferson County 2001 Series A and Louisville Metro 2007 Series B bonds from "A" to "BBB+" in June 2009. The S&P ratings of these bonds are now based on the rating of the Company rather than the rating of Ambac since the Company's rating is higher.

During 2008, LG&E converted several series of its pollution control bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with these conversions, LG&E purchased the bonds from the remarketing agent. As of September 30, 2009, LG&E continued to hold repurchased bonds in the amount of $163 million. The other repurchased bonds were remarketed during 2008 in an intermediate-term fixed rate mode wherein the interest rate is reset periodically (every three to five years). 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.

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) 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, 2009	$ 400	$ 149	$ 251	0.25%
December 31, 2008	$ 400	$ 222	$ 178	1.49%

E.ON U.S. maintains revolving credit facilities totaling $313 million at September 30, 2009 and December 31, 2008, to ensure funding availability for the money pool. At September 30, 2009, 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 balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2009	$ 313	$ 246	$ 67	1.66%
December 31, 2008	$ 313	$ 299	$ 14	2.05%

As of September 30, 2009, LG&E maintained bilateral lines of credit, with unaffiliated financial institutions, totaling $125 million which mature in June 2012. At September 30, 2009, there was no balance outstanding under any of these facilities.

There were no redemptions or issuances of long-term debt year-to-date through September 30, 2009.

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, 2008 (including, but not limited to Notes 2, 9 and 14 to the financial statements of LG&E contained therein). See LG&E's Annual Report regarding such commitments or contingencies.

Construction Program. LG&E had $33 million of commitments in connection with its construction program at September 30, 2009.

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. In March 2009, the parties completed an agreement resolving certain 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 is estimated to 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 object to the state air permit and in April 2008, they filed a petition seeking an EPA objection to 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. As part of a routine permit renewal, the KDAQ revised the permit to address the issues identified in the EPA's Order. In June 2009, the EPA objected to the permit renewal on the grounds that it failed to include a case by case Maximum Achievable Control Technology analysis and required additional changes to language addressing startup and shutdown operations. In August 2009, the EPA issued an order relating to all existing current issues in the TC2 air permit proceeding. The EPA supported the Company's positions on all but two issues. The permit was remanded to the KDAQ to correct deficiencies concerning matters relating to an auxiliary boiler and the appropriate particulate standard to apply. The Company generally believes both of these matters should not have a material adverse effect on its financial condition or results of operations. The Company is currently analyzing the order and possible future actions and cannot predict the final outcome of this proceeding. [update]

Reserve Sharing Developments. LG&E and KU are currently members of the Midwest Contingency Reserve Sharing Group which will terminate on December 31, 2009. LG&E and KU are finalizing alternative arrangements for sharing contingency reserve which involves the formation and participation in a new reserve sharing group. Contingency reserves, including spinning reserves and supplemental reserves, relate to power or capacity requirements the Companies must have available for certain reliability purposes. The determination of whether to self supply or contract for such reserve sharing has certain operational or financial impacts. The Companies believe it is very likely that the new group will start operations on January 1, 2010. [monitor updates]

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 place 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 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 Clean Air Visibility Rule 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 approval to recover the costs incurred by LG&E for these projects through the 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. As discussed below, 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 and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. If enacted into law, the bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020, and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency. Senate action on similar legislation is not expected until later this year. [update]

Separately, at the administrative level, in April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding could potentially result in EPA regulations governing GHG emissions from motor vehicles, power plants and other sources.

LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. 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. While the Company believes that many costs of complying with mandatory GHG reduction requirements or purchasing emission allowances to meet applicable requirements would likely be recoverable, in whole or in part under the ECR, where such costs are related to the Company's coal-fired generating assets, or other potential cost-recovery mechanisms, this cannot be assured.

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 polychlorinated biphenyl 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 8 - Segments of Business

LG&E's revenues, net income and total assets by business segment follow:

(in millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
LG&E Electric				
Revenues	$ 250	$ 283	$ 712	$ 747
Net income	55	37	70	70
Total assets	2,832	2,637	2,832	2,637
LG&E Gas				
Revenues	28	47	270	295
Net income	(5)	(4)	6	3
Total assets	712	774	712	774
Total				
Revenues	278	330	982	1,042
Net income	50	33	76	73
Total assets	3,544	3,411	3,544	3,411

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 the Public Utility Holding Company Act of 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's intercompany electric revenues and purchased power expense were as follows:

(in millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Electric operating revenues from KU	$ 21	$ 21	$ 79	$ 73
Purchased power from KU	1	15	15	44

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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Interest on money pool loans	$ 1	$ 2	$ 1	$ 4
Interest on Fidelia loans	7	6	20	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 and hourly 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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
E.ON U.S. Services billings to LG&E	$ 37	$ 50	$ 132	$ 152
LG&E billings to KU	-	-	-	5
KU billings to LG&E	16	21	63	58
LG&E billings to E.ON U.S. Services	1	1	1	4

In March and June 2009, LG&E paid dividends of $35 million and $45 million, respectively to its common shareholder, E.ON U.S.

Note 10 - Subsequent Events

Subsequent events have been evaluated through November 12, 2009, the date of issuance of these statements and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

Management's Discussion and Analysis

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, 2009, 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, 2008.

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. LG&E provides electric service to approximately 391,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in 9 counties. Natural gas service is provided to approximately 316,000 customers in its electric service area and 8 additional counties in Kentucky. Approximately 98% 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 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. 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.

Regulatory Matters

In January 2009, LG&E, the AG, KIUC and all other parties to electric and gas base 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 in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, which will result in increased revenues of approximately $21 million annually.

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 $47 million of operation and maintenance expenses and $10 million of capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009 winter storms.

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.

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. Recent developments indicate an increased possibility of significant climate-change or greenhouse gas legislation or regulation, particularly at the federal level. While the final terms and impacts of such initiatives cannot be estimated, as a primarily coal-fueled utility, LG&E could be highly affected by such proceedings. Ultimately, environmental matters or potential environmental matters can represent an important element of current or future capital requirements, operating and maintenance expenses or compliance risks for the Company. 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, 2009, Compared to Three Months Ended September 30, 2008

Net Income

Net income for the three months ended September 30, 2009, increased $17 million compared to the same period in 2008. The increase was primarily the result of decreased operating expenses ($95 million), partially offset by decreased operating revenues ($52 million), increased income taxes ($16 million) and increased other expense – net ($10 million).

Revenues

Electric revenues decreased $33 million in the three months ended September 30, 2009, primarily due to:

- Decreased wholesale sales ($22 million) due to lower sales volumes with third-parties ($27 million) as a result of scheduled coal-fired generation unit outages during July 2009, and lower economic capacity caused by lower spot market pricing in the third quarter of 2009. Gains in energy marketing financial swaps ($5 million) offset decreased wholesale sales.
- Decreased retail sales volumes delivered ($14 million) due to mild weather and weakened economic conditions
- Decreased base rates ($10 million) due to the application of the Kentucky base rate case settlement in February 2009
- Decreased fuel costs billed to customers through the FAC ($1 million) due to lower fuel prices
- Increased DSM revenue ($5 million) due to increased recoverable program spending
- Increased ECR surcharge ($4 million) due to increased recoverable capital spending
- Decreased merger surcredit ($3 million) due to the surcredit termination in February 2009
- Decreased VDT surcredit ($1 million) due to its termination in August 2008
- Increased miscellaneous revenue ($1 million) due to late payment charges resulting from weakened economic conditions

Natural gas revenues decreased $19 million in the three months ended September 30, 2009, primarily due to:

- Decreased average cost of gas billed to retail customers through the GSC ($20 million) due to decreased natural gas supply costs
- Decreased retail sales volumes delivered ($2 million) due to weakened economic conditions
- Increased base rates ($2 million) due to application of the base rate case settlement in February 2009
- Increased DSM revenue ($1 million) due to increased recoverable program spending

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expenses. 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 decreased $13 million in the three months ended September 30, 2009, primarily due to:

- Decreased commodity and transportation costs for gas and coal ($10 million)
- Decreased volumes of fuel usage ($3 million) due to decreased native load and wholesale sales

Power purchased expense decreased $17 million in the three months ended September 30, 2009, primarily due to:

- Decreased purchased volumes from KU ($15 million) as a result of KU's units held in reserve as a result of low spot market pricing during the third quarter of 2009. Via a mutual agreement, LG&E sells its lower cost electricity to KU to serve KU's native load and purchases KU's excess economic capacity for LG&E to make wholesale sales.
- Decreased prices for third-party purchases ($2 million) due to lower native load prices as a result of lower spot market pricing

Gas supply expenses decreased $22 million in the three months ended September 30, 2009, due to decreased cost of net gas supply billed to customers and lower GSC expenses resulting from lower cost per Mcf.

Other operation and maintenance expense decreased $46 million in the three months ended September 30, 2009, due to decreased maintenance expense ($56 million) and offset by increased other operation expense ($10 million).

Maintenance expense decreased $56 million in the three months ended September 30, 2009, primarily due to:

- Decreased distribution expense ($55 million) due to the reclassification of 2009 wind and ice storm expenses as a regulatory asset
- Decreased underground storage expense ($1 million) due to timing of scheduled maintenance on reservoirs/wells

Other operation expense increased $10 million in the three months ended September 30, 2009, primarily due to:

- Increased administrative and general expense ($11 million) due to timing of DSM expenditures
- Increased pension expense ($6 million) due to lower 2008 pension asset investment performance
- Decreased distribution operation expense ($7 million) due to the reclassification of 2009 wind and ice storm restoration expenses to a regulatory asset

Other expense – net increased $10 million in the three months ended September 30, 2009, primarily due to a gain in 2008 on the sale of the Company's Waterside property to the

Louisville Arena Authority ($9 million) and ($2 million) due to a change in the mark-to-market power purchase swaps resulting from price increases in 2009 and price decreases in 2008.

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

	Three Months Ended September 30,	
	2009	2008
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	3.3	(1.7)
Qualified production activities deduction	(0.3)	(1.0)
Amortization of investment tax credits	(1.0)	(2.2)
Other differences	(0.3)	(1.8)
Effective income tax rate	36.7 %	28.3 %

The effective income tax rate increased for the three months ended September 30, 2009, compared to the three months ended September 30, 2008, primarily due to increased pretax income. State income taxes, net of federal benefit increased for the three months ended September 30, 2009 compared to the three months ended September 30, 2008 due to a recycle credit in 2008. The variances between the individual line items are primarily due to amounts for the period ended September 30, 2009, representing a smaller proportion of pretax income. The pretax income increased 72% for the three months ended September 30, 2009, compared to the three months ended September 30, 2008.

Nine Months Ended September 30, 2009, Compared to
Nine Months Ended September 30, 2008

Net Income

Net income for the nine months ended September 30, 2009, increased $3 million compared to the same period in 2008. The increase was primarily the result of decreased operating expense ($56 million), increased other income – net ($12 million) and decreased interest expense ($3 million), partially offset by decreased revenues ($60 million) and increased income taxes ($8 million).

Revenues

Electric revenues decreased $35 million in the nine months ended September 30, 2009, primarily due to:

- Decreased wholesale sales ($40 million) due to lower sales volumes with third-parties ($50 million) as a result of scheduled coal-fired generation unit outages during January through April 2009, and lower economic capacity caused by lower spot market pricing during the majority of 2009. Third-party prices decreased ($5 million) as a result of lower spot market pricing. These decreases were offset by increased sales volumes to KU ($11 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 KU's native load and purchases KU's excess economic capacity for LG&E to make wholesale sales. Decreased fuel costs for sales to KU ($4 million) and gains in energy marketing financial swaps ($8 million) also offset decreased wholesale sales.

- Decreased retail sales volumes delivered ($26 million) due to weakened economic conditions, significant 2009 storm outages and mild weather
- Decreased base rates ($10 million) due to the application of the Kentucky base rate case settlement in February 2009
- Increased fuel costs billed to customers through the FAC ($12 million) due to increased fuel prices
- Decreased merger surcredit ($11 million) due to a lower rate approved by the Kentucky Commission in June 2008, and the surcredit termination in February 2009
- Increased ECR surcharge ($7 million) due to increased recoverable capital spending
- Increased DSM revenue ($5 million) due to increased recoverable program spending
- Decreased VDT surcredit ($4 million) due to its termination in August 2008
- Increased miscellaneous revenue ($3 million) due to late payment charges resulting from weakened economic conditions

Natural gas revenues decreased $25 million in the nine months ended September 30, 2009, primarily due to:

- Decreased sales volumes ($18 million) due to weakened economic conditions
- Decreased wholesale sales ($7 million) due to lower demand from wholesale customers
- Decreased average cost of gas billed to retail customers through the GSC ($7 million) due to decreased natural gas supply costs
- Increased base rates ($4 million) due to the application of the Kentucky base rate case settlement in February 2009
- Increased miscellaneous revenue ($1 million) due to late payment charges resulting from weakened economic conditions
- Decreased VDT surcredit ($1 million) due to its termination in August 2008

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expenses. 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 decreased $1 million in the nine months ended September 30, 2009, primarily due to:

- Decreased volumes of fuel usage ($4 million) due to decreased native load and wholesale sales
- Increased commodity and transportation costs for coal ($3 million)

Power purchased expense decreased $32 million in the nine months ended September 30, 2009, primarily due to:

- Decreased purchased volumes from KU ($32 million) as a result of KU's scheduled coal-fired generation unit outages during January through April 2009, and KU's units held in reserve as a result of low spot market pricing for the majority of 2009
- Decreased volumes ($1 million) and prices ($1 million) for third-party purchases due to lower native load requirements and lower spot market pricing, respectively
- Increased prices for purchases from KU ($2 million) due to native load demand payments on long-term contracts

Gas supply expenses decreased $35 million in the nine months ended September 30, 2009, primarily due to:

- Decreased cost of net gas supply billed to customers ($29 million) resulting from lower volumes and cost per Mcf offset by higher GSC expenses
- Decreased expense ($6 million) due to a decline in volume of wholesale sales of purchased gas

Other operation and maintenance expense increased $5 million in the nine months ended September 30, 2009, due to increased other operation expense ($25 million) and offset by decreased maintenance expense ($20 million).

Other operation expense increased $25 million in the nine months ended September 30, 2009, primarily due to:

- Increased pension expense ($18 million) due to lower 2008 pension asset investment performance
- Increased administrative and general expense ($13 million) due to timing of DSM expenditures, consulting fees for software training and increased labor costs
- Increased property tax ($1 million) due to higher tax assessment resulting from construction expenditures
- Decreased distribution expense ($7 million) due to repair of overhead lines and miscellaneous distribution expense as a result of 2008 wind storm not reclassified to regulatory asset until the fourth quarter of 2008
- Decreased transmission expense ($1 million) due to the establishment of regulatory assets approved by the Kentucky Commission for EKPC settlement and MISO refund and lower off-system transmission purchases from KU resulting from units held in reserve as a result of low spot market pricing which reduced excess generation

Maintenance expense decreased $20 million in the nine months ended September 30, 2009, primarily due to:

- Decreased distribution expense ($15 million) due to tree trimming, maintenance of overhead lines and line transformers as a result of 2008 wind storm not reclassified to regulatory asset until the fourth quarter of 2008
- Decreased steam maintenance expense ($6 million) due to timing of scheduled unit outages and routine maintenance
- Increased administrative and general expense ($1 million) due to increased labor and system maintenance contracts resulting from completion of a significant in-house customer information system project

Other income – net increased $12 million in the nine months ended September 30, 2009, primarily due to:

- Increased ($20 million) due to a gain from the change in the mark-to-market value of ineffective interest rate swaps
- Increased ($2 million) due to the change in the ineffective portion of the effective interest rate swap
- Decreased as a result of a 2008 gain on the sale of the Company's Waterside property to the Louisville Arena Authority ($9 million)
- Decreased ($1 million) due to a change in the mark-to-market power purchase swaps resulting from price decreases in 2009 and price increases in 2008

Interest expense, including interest expense to affiliated companies, decreased $3 million in the nine months ended September 30, 2009, primarily due to lower interest rates on bonds.

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

	Nine Months Ended September 30,	
	2009	2008
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	2.8	0.9
Qualified production activities deduction	(0.4)	(1.2)
Amortization of investment tax credits	(2.0)	(2.8)
Other differences	(0.4)	(0.8)
Effective income tax rate	35.0 %	31.1 %

The effective income tax rate increased for the nine months ended September 30, 2009, compared to the nine months ended September 30, 2008, primarily due to a decrease in the qualified production activities deduction due to changes in the level of taxable income and an increase in state income tax, net of federal benefit.

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. As of September 30, 2009, LG&E had a working capital deficiency of $194 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 Company has adequate liquidity facilities to repurchase any bonds put back to the Company. The repurchased 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

The $114 million increase in net cash provided by operating activities for the nine months ended September 30, 2009 compared to September 30, 2008, was primarily the result of changes in:

- Materials and supplies ($81 million) primarily due to increased volumes
- Accounts receivable ($66 million) primarily due to timing on collection of accounts
- Gas supply clause receivable, net ($44 million) due to the timing of GSC collections
- Earnings, net of non-cash items ($33 million)
- Fuel adjustment clause receivable ($7 million)
- Collateral deposit – interest rate swap ($7 million) due to decreased collateral required related to decrease in derivative liability
- Other current assets and liabilities ($4 million)

These increases were partially offset by changes in:

- Accounts payable ($52 million) primarily due to payments relating to 2009 winter storm restoration, timing of other payments and lower accruals
- Storm restoration regulatory asset ($44 million) due to the establishment of a regulatory asset for the 2009 winter storm expenses
- Accrued income taxes ($14 million)
- Pension and postretirement funding ($9 million)
- Other ($8 million)
- Long-term derivative liability ($1 million) primarily due to market conditions

Investing Activities

Net cash used for investing activities decreased $33 million in the nine months ended September 30, 2009, compared to 2008. The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $127 million and $179 million in the nine months ended September 30, 2009 and 2008, respectively, a net decrease of $52 million. This decrease was partially offset by a decrease in assets transferred to KU for TC2 of $10 million and decreased proceeds from the sale of assets of $9 million.

Financing Activities

Net cash flows used for financing activities were $153 million and $8 million in the nine months ended September 30, 2009 and 2008, respectively, resulting in an increase in net cash used for financing activities of $145 million. The increase in financing cash outflows is due to lower long-term borrowings from an affiliated company of $25 million, lower short-term borrowings net of repayments from an affiliated company of $339 million and increased dividend payments of $40 million, partially offset by decreased reacquisition of long-term bonds of $259 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, 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, construction of TC2 totaling approximately $35 million (including $5 million for environmental controls), redevelopment of the Ohio Falls hydroelectric facility totaling approximately $35 million, and information technology projects of approximately $35 million.

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. Credit market conditions can affect aspects of the availability, terms or methods in which the Company funds its capital 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 the Company at market-based rates. See Note 6 of Notes to Financial Statements. Fidelia also provides long-term intercompany funding to LG&E.

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. As of September 30, 2009, LG&E has borrowed $149 million of this authorized amount. See Note 6 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 September 30, 2009, 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 6 of Notes to Financial Statements for a discussion of 2008 and 2009 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

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. Effective April 1, 2009, the Company initiated a new software and data system for customer accounts and associated billing, management, operations and record-keeping aspects thereof, following a comprehensive planning, testing and implementation project. There were no changes to the Company's internal controls as a result of the new software implementation. There have been no changes in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2009, that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2008 LG&E Annual Report.

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, 2008: 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 for the year ended December 31, 2008 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, the Company 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.

Document Revisions
Total Revisions: 7

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	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1										
2	(in millions)							Pension Benefits		
3										
4							Total			
5			LG&E		Servco Allocation to LG&E		LG&E		LG&E	
6			2009		2009		2009		2008	
7	Service cost									
8	Interest cost									
9	Expected return on									
10	plan assets									
11	Amortization of prior									
12	service costs									
13	Amortization of									
14	actuarial loss									
15	Benefit cost at end									
16	of year		$ -		$ -		$ -		$ -	
17										
18								Other Postretirement Benefits		
19										
20										
21							Total			
22			LG&E		Servco Allocation to LG&E		LG&E		LG&E	
23			2009		2009		2009		2008	
24	Service cost									
25	Interest cost									
26	Amortization of prior									
27	service costs									
28	Benefit cost at end									
29	of year		$ -		$ -		$ -		$ -	

	K	L	M
1			
2			
3			
4			Total
5	Servco Allocation to LG&E		LG&E
6	2008		2008
7			
8			
9			
10			
11			
12			
13			
14			
15			
16	$ -		$ -
17			
18			
19			
20			
21			Total
22	Servco Allocation to LG&E		LG&E
23	2008		2008
24			
25			
26			
27			
28			
29	$ -		$ -

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1								Pension Benefits		
2	(in millions)							Three Months Ended September 30,		
3					2009					
4										
5										
6							Total			
7			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
8	Service cost		$ 1		$ 1		$ 2		$ 1	
9	Interest cost		7		2		9		7	
10	Expected return on									
11	plan assets		(6)		(1)		(7)		(8)	
12	Amortization of prior									
13	service costs		1		-		1		1	
14	Amortization of									
15	actuarial loss		3		-		3		-	
16	Benefit cost		$ 6		$ 2		$ 8		$ 1	
17										
18								Other Postretirement Benefits		
19								Nine Months Ended June 30,		
20										
21					2009					
22										
23										
24							Total			
25			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
26	Service cost						$ -			
27	Interest cost						-			
28	Amortization of prior									
29	service costs						-			
30	Benefit cost at end									

	K	L	M
1			
2			
3	2008		
4			
5			
6			Total
7	E.ON U.S. Services Allocation to LG&E		LG&E
8	$ 1		$ 2
9	1		8
10			
11	(1)		(9)
12			
13	-		1
14			
15	-		-
16	$ 1		$ 2
17			
18			
19			
20			
21	2008		
22			
23			
24			Total
25	E.ON U.S. Services Allocation to LG&E		LG&E
26			$ -
27			-
28			
29			-
30			

	A	B	C	D	E	F	G	H	I	J
31	of year		$ -		$ -		$ -		$ -	

	K	L	M
31	$ -		$ -

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1								Pension Benefits		
2	(in millions)							Nine Months Ended June 30,		
3					2009					
4										
5										
6							Total			
7			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
8	Service cost						$ -			
9	Interest cost						-			
10	Expected return on									
11	plan assets						-			
12	Amortization of prior									
13	service costs						-			
14	Amortization of									
15	actuarial loss						-			
16	Benefit cost		$ -		$ -		$ -		$ -	
17										
18								Other Postretirement Benefits		
19	(in millions)							Three Months Ended September 30,		
20					2009					
21										
22										
23							Total			
24			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
25	Service cost		$ -		$ -		$ -		$ -	
26	Interest cost		$ 1		$ -		$ 1		$ 1	
27	Amortization of prior									
28	service costs		1		-		1		1	
29	Benefit cost		$ 2		$ -		$ 2		$ 2	

	K	L	M
1			
2			
3	2008		
4			
5			
6			Total
7	E.ON U.S. Services Allocation to LG&E		LG&E
8			$ -
9			-
10			
11			-
12			
13			-
14			
15			-
16	$ -		$ -
17			
18			
19			
20	2008		
21			
22			
23			Total
24	E.ON U.S. Services Allocation to LG&E		LG&E
25	$ -		$ -
26	$ -		$ 1
27			
28	-		1
29	$ -		$ 2

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1								Pension Benefits		
2	(in millions)							Nine Months Ended September 30,		
3					2009					
4										
5										
6							Total			
7			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
8	Service cost		$ 3		$ 3		$ 6		$ 3	
9	Interest cost		19		5		24		19	
10	Expected return on									
11	plan assets		(16)		(4)		(20)		(23)	
12	Amortization of prior									
13	service costs		4		1		5		4	
14	Amortization of									
15	actuarial loss		9		2		11		1	
16	Benefit cost		$ 19		$ 7		$ 26		$ 4	
17										
18								Other Postretirement Benefits		
19								Nine Months Ended June 30,		
20										
21					2009					
22										
23										
24							Total			
25			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
26	Service cost						$ -			
27	Interest cost						-			
28	Amortization of prior									
29	service costs						-			
30	Benefit cost at end									

	K	L	M
1			
2			
3	2008		
4			
5			
6			Total
7	E.ON U.S. Services Allocation to LG&E		LG&E
8	$ 3		$ 6
9	4		23
10			
11	(4)		(27)
12			
13	1		5
14			
15	-		1
16	$ 4		$ 8
17			
18			
19			
20			
21	2008		
22			
23			
24			Total
25	E.ON U.S. Services Allocation to LG&E		LG&E
26			$ -
27			-
28			
29			-
30			

	A	B	C	D	E	F	G	H	I	J
31	of year		$ -		$ -		$ -		$ -	

	K	L	M
31	$ -		$ -

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	**Change in benefit obligation**								
5	Benefit obligation at beginning of year				$ 318				$ 95
6	Service cost				6				2
7	Interest cost				17				5
8	Benefits paid, net of retiree contributions				(19)				(5)
9	Actuarial (gain) or loss and other				(19)				(9)
10	Benefit obligation at end of year		$ -		$ 303		$ -		$ 88
11									
12	**Change in plan assets**								
13	Fair value of plan assets at beginning of year				$ 247				$ 9
14	Actual return on plan assets				26				1
15	Employer contributions				-				7
16	Benefits paid, net of retiree contributions				(19)				-
17	Administrative expenses				(1)				(5)
18	Fair value of plan assets at end of year				$ 253		$ -		$ 12
19									
20	Funded status at end of year		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4	Prior to the application of SFAS No. 158:								
5									
6	Accrued benefit liability				$ (4)				$ (71)
7	Intangible asset				6				-
8	Accumulated other comprehensive income				7				-
9									
10	After the application of SFAS No. 158:								
11									
12	Regulatory assets				59				5
13	Accrued benefit liability				(50)				(76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Funded status				$ (50)				$ (76)
6	Unrecognized prior service costs				N/A				N/A
7	Unrecognized actuarial (gain) loss				N/A				N/A
8	Unrecognized transition obligation				N/A				N/A
9	Other comprehensive income				N/A				N/A
10	Accrued benefit liability		$ -		$ (50)		$ -		$ (76)

	A	B	C	D	E	F	G	H	I
1							Other Postretirement		
2	(in millions)		Pension Benefits				Benefits		
3			2007		2006		2007		2006
4									
5	Benefit obligation				$ 303				$ 88
6	Accumulated benefit obligation				258				-
7	Fair value of plan assets				253				12

	A	B	C	D	E	F	G	H	I	J
1								Pension Benefits		
2	(in millions)							Nine Months Ended June 30,		
3					2009					
4										
5										
6							Total			
7			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
8	Service cost						$ -			
9	Interest cost						-			
10	Expected return on									
11	plan assets						-			
12	Amortization of prior									
13	service costs						-			
14	Amortization of									
15	actuarial loss						-			
16	Benefit cost at end									
17	of year		$ -		$ -		$ -		$ -	
18										
19								Other Postretirement Benefits		
20	(in millions)							Nine Months Ended September 30,		
21					2009					
22										
23										
24							Total			
25			LG&E		E.ON U.S. Services Allocation to LG&E		LG&E		LG&E	
26	Service cost		$ 1		$ 1		$ 2		$ 1	
27	Interest cost		4		-		4		4	
28	Amortization of prior									
29	service costs		1		-		1		1	
30	Benefit cost		$ 6		$ 1		$ 7		$ 6	

	K	L	M
1			
2			
3	2008		
4			
5			
6			Total
7	E.ON U.S. Services Allocation to LG&E		LG&E
8			$ -
9			-
10			
11			-
12			
13			-
14			
15			-
16			
17	$ -		$ -
18			
19			
20			
21	2008		
22			
23			
24			Total
25	E.ON U.S. Services Allocation to LG&E		LG&E
26	$ 1		$ 2
27	-		4
28			
29	-		1
30	$ 1		$ 7