KU®

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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

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MAY 27 2010
PUBLIC SERVICE COMMISSION

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
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Robert M. Conroy
Director - Rates
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May 27, 2010

RE: ***APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS BASE RATES* - Case No. 2009-00548 (Updates to Question Nos. 43, 44, and 55; AG-1 Question No. 188)**

Dear Mr. DeRouen:

On February 16, 2010, in the above-referenced proceeding, Kentucky Utilities Company ("KU") filed initial responses to Question Nos. 43, 44, and 55 of the First Data Request of Commission Staff dated January 19, 2010. Pursuant to the directives in each of these data requests, KU hereby provides an original and ten (10) copies of the following information:

- PSC-1 Question No. 43 - updated Rives Exhibit 2 and Analysis of Embedded Cost of Capital to reflect changes through April 30, 2010.

- PSC-1 Question No. 44 - detailed monthly income statements for April 2010.

- PSC-1 Question No. 55 - updated actual rate case expenses through April 30, 2010.

In response to Question No. 188 of the Attorney General's Initial Requests for Information dated March 1, 2010, KU stated it would provide the 2009 financial statements once available. KU hereby provides an original and ten (10) copies of the Updated Response to Question No. 188 with the E.ON U.S. LLC 2009 financial statements.

Please confirm your receipt of these documents by placing the File Stamp of your Office on the enclosed additional copy.

Please contact me if you have any questions about this filing.

Sincerely,

Robert M. Conroy

Enclosures

cc: Parties of Record

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

SBRives

S. Bradford Rives

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott

Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2010.

Victoria B. Harper (SEAL)

Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director – Utility Accounting and Reporting for E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L. Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

UPDATED Response to First Data Request of Commission Staff
Dated January 19, 2010

Updated Response filed May 27, 2010

Question No. 43

Responding Witness: S. Bradford Rives

Q-43. Provide any information, when known, that would have a material effect on net operating income, rate base, or cost of capital that has occurred after the test year but were not incorporated in the filed testimony and exhibits.

A-43. See attached Updated Rives Exhibit 2 and Analysis of the Embedded Cost of Capital, reflecting changes to embedded cost of capital through April 30, 2010.

KENTUCKY UTILITIES

Capitalization at October 31, 2009
Revised Trimble County Joint Use Assets Transfer (Col 3) & (Col 4)
with Annual Cost Rate as of April 30, 2010

		Per Books 10-31-09 (1)	Capital Structure (2)	Trimble County Joint Use Assets Transfer (Net Plant) (3)	Trimble County Joint Use Assets Transfer (ITC) (4)	Undistributed Subsidiary Earnings (5)	Investment in EEI (Col 2 x Col 6 Line 4) (6)	Investments in OVEC and Other (Col 2 x Col 7 Line 4) (7)	Adjustments to Total Co. Capitalization (Sum of Col 3 - Col 7) (8)	Adjusted Total Company Capitalization (Col 1 + Col 8) (9)	Jurisdictional Rate Base Percentage (Exhibit 3 Line 19) (10)	Kentucky Jurisdictional Capitalization (Col 9 x Col 10) (11)
1.	Short Term Debt	$ 19,665,954	0.55%	$ 266,095	$ (16,104)	$ -	$ (7,127)	$ (4,621)	$ 238,243	$ 19,904,197	87.15%	$ 17,346,508
2.	Long Term Debt	1,631,779,405	45.52%	22,022,972	(1,332,807)	-	(589,848)	(382,487)	19,717,830	1,651,497,235	87.15%	1,439,279,840
3.	Common Equity	1,933,128,508	53.93%	26,091,802	(1,579,048)	(6,207,858)	(698,825)	(453,153)	17,152,918	1,950,281,425	87.15%	1,699,670,262
4.	Total Capitalization	$ 3,584,573,867	100.00%	$ 48,380,869	$ (2,927,959)	$ (6,207,858)	$ (1,295,800)	$ (840,261)	$ 37,108,991	$ 3,621,682,857		$ 3,156,296,610

		Kentucky Jurisdictional Capitalization (11)	Capital Structure (12)	Environmental Compliance Plans (a) (Col 12 x Col 13 Line 4) (13)	Adjusted Kentucky Jurisdictional Capitalization (Col 11 + Col 13) (14)	Adjusted Capital Structure (15)	Annual Cost Rate April 30, 2010 (16)	Cost of Capital (Col 16 x Col 15) (17)
1.	Short Term Debt	$ 17,346,508	0.55%	$ (573,676)	$ 16,772,832	0.55%	0.21%	0.00%
2.	Long Term Debt	1,439,279,840	45.60%	(47,562,946)	1,391,716,894	45.60%	4.69%	2.14%
3.	Common Equity	1,699,670,262	53.85%	(56,168,084)	1,643,502,178	53.85%	11.50%	6.19%
4.	Total Capitalization	$ 3,156,296,610	100.00%	$ (104,304,706)	$ 3,051,991,904	100.00%		8.33%

(a) Environmental Compliance Plans:

Total Jurisdictional ECR Rate Base at 10/31/09	$ 1,120,801,977
Less: Juris ECR Rate Base '01 and '03 Plans	149,293,659
Less: Juris ECR Rate Base Roll-In '05 and '06 Plans	867,203,612
Jurisdictional ECR Post '03 Rate Base	$ 104,304,706

NOTES:
Column 16 used April 30, 2010 actual embedded cost rates.

KENTUCKY UTILITIES COMPANY
ANALYSIS OF THE EMBEDDED COST OF CAPITAL AT
April 30, 2010

LONG-TERM DEBT

	Due	Rate	Principal	Annualized Cost: Interest	Amortized Debt Issuance Expense	Amortized Loss-Reacquired Debt	Letter of Credit and other fees	Total	Embedded Cost
Pollution Control Bonds									
Mercer Co 2000 Series A	05/01/23	0 34000% *	12.900,000	43,860	-	46,743	94,413 a	185,016	1 434%
Carroll Co 2002 Series A	02/01/32	0 60000% *	20.930.000	125.580	4,104	36,300	20,930 b	186,914	0 893%
Carroll Co 2002 Series B	02/01/32	0 60000% *	2.400,000	14,400	2,856	4,164	2,400 b	23,820	0 993%
Muhlenberg Co 2002 Series A	02/01/32	0 60000% *	2.400.000	14,400	1,140	12,744	2,400 b	30,684	1 279%
Mercer Co 2002 Series A	02/01/32	0 60000% *	7,400,000	44,400	3,180	12,900	7,400 b	67.880	0 917%
Carroll Co 2002 Series C	10/01/32	0 60300% *	96.000,000	578,880	73,658	186,036	240,000 c	1,078,574	1 124%
Carroll Co 2004 Series A	10/01/34	0 33000% *	50,000,000	165,000	-	105.023	409,041 d	679.064	1 358%
Carroll Co 2006 Series B	10/01/34	0 33000% *	54,000,000	178,200	47,757	-	441,990 d	667,947	1 237%
Carroll Co 2007 Series A	02/01/26	5 75000% *	17.875,000	1,027,813	33,166	-	-	1.060,979	5 936%
Trimble Co 2007 Series A	03/01/37	6 00000% *	8,927,000	535,620	16,022	-	-	551,642	6 179%
Carroll Co 2008 Series A	02/01/32	0 33000% *	77,947,405	257,226	34,268	-	636,669 d	928,163	1 191%
Called Bonds			-	-	-	200,687 1		200,687	0 000%
Total External Debt			350,779,405	2,985,379	216,151	604,597	1,855,243	5,661,370	0 337%
Notes Payable to Fidelia Corp	11/24/10	4 240%	33,000,000	1,399,200	-	-	-	1,399,200	4 240%
Notes Payable to Fidelia Corp	01/16/12	4 390%	50,000,000	2,195,000	-	-	-	2,195,000	4 390%
Notes Payable to Fidelia Corp	04/30/13	4 550%	100,000,000	4,550,000	-	-	-	4,550,000	4 550%
Notes Payable to Fidelia Corp	08/15/13	5 310%	75,000,000	3,982,500	-	-	-	3,982,500	5 310%
Notes Payable to Fidelia Corp	12/19/14	5 450%	100,000,000	5,450,000	-	-	-	5,450,000	5 450%
Notes Payable to Fidelia Corp	07/08/15	4 735%	50,000,000	2,367,500	-	-	-	2,367,500	4 735%
Notes Payable to Fidelia Corp	12/21/15	5 360%	75,000,000	4,020,000	-	-	-	4,020,000	5 360%
Notes Payable to Fidelia Corp	10/25/16	5 675%	50,000,000	2,837,500	-	-	-	2,837,500	5 675%
Notes Payable to Fidelia Corp	06/20/17	5 980%	50,000,000	2,990.000	-	-	-	2,990,000	5 980%
Notes Payable to Fidelia Corp	07/25/18	6 160%	50,000,000	3,080,000	-	-	-	3,080,000	6 160%
Notes Payable to Fidelia Corp	08/27/18	5 645%	50,000,000	2,822,500	-	-	-	2.822.500	5 645%
Notes Payable to Fidelia Corp	12/17/18	7 035%	75,000,000	5,276,250	-	-	-	5,276,250	7 035%
Notes Payable to Fidelia Corp	10/25/19	5 710%	70,000,000	3,997,000	-	-	-	3,997,000	5 710%
Notes Payable to Fidelia Corp	02/07/22	5 690%	53,000,000	3,015,700	-	-	-	3,015,700	5 690%
Notes Payable to Fidelia Corp	05/22/23	5 850%	75,000,000	4,387,500	-	-	-	4,387.500	5 850%
Notes Payable to Fidelia Corp	09/14/28	5 960%	100,000,000	5,960,000	-	-	-	5,960,000	5 960%
Notes Payable to Fidelia Corp	06/23/36	6 330%	50,000,000	3,165,000	-	-	-	3,165,000	6 330%
Notes Payable to Fidelia Corp	03/30/37	5 860%	75,000,000	4,395,000	-	-	-	4,395,000	5 860%
Notes Payable to Fidelia Corp	04/24/17	5 280%	50,000,000	2,640,000	-	-	-	2,640,000	5 280%
Notes Payable to Fidelia Corp	07/29/19	4 810%	50,000,000	2,405,000	-	-	-	2,405,000	4 810%
Notes Payable to Fidelia Corp	11/25/19	4 445%	50,000,000	2,222,500	-	-	-	2,222,500	4.445%
Total Internal Debt			1,331,000,000	73,158,150	-	-	-	73,158,150	4.350%
		Total	1,681,779,405	76,143,529	216,151	604,597	1,855,243	78,819,520	4.687%

SHORT TERM DEBT

	Rate	Principal	Annualized Cost: Interest	Expense	Loss	Premium	Total	Embedded Cost
Notes Payable to Associated Company	0 210% *	56,583,954	118,826	-	-	-	118,826	0 210%
	Total	56,583,954	118,826	-	-	-	118,826	0.210%

	Principal	Interest	Expense	Loss	Fees	Total	Embedded Cost
Embedded Cost of Total Debt	1,738,363,359	76,262,355	216,151	604,597	1,855,243	78,938,346	4.541%

* Composite rate at end of current month

1 Series P and R bonds were redeemed in 2003, and 2005, respectively They were not replaced with other bond series The remaining unamortized expense is being amortized over the remainder of the original lives (due 5/15/07, 6/1/25, 6/1/35, and 6/1/36 respectively) of the bonds as loss on reaquired debt

a - Letter of credit fee = (principal bal + 45 days interest)* 70% Rate based on company credit rating Additional fee of $250/month for drawdown
b - Remarketing fee = 10 basis points
c - Remarketing fee = 25 basis points
d - Is a and b combined

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

UPDATED Response to First Data Request of Commission Staff
Dated January 19, 2010

Updated Response filed May 27, 2010

Question No. 44

Responding Witness: Shannon L. Charnas

Q-44. Provide detailed monthly income statements for each month after the test year, including the month in which the hearing ends, as they become available.

A-44. See attached income statements for April 2010.

KENTUCKY UTILITIES COMPANY

Income Statements

April 30, 2010

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2010

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	103,746,048.86	102,853,016.39	893,032.47	0.87
Rate Refunds	-	-	-	-
Total Operating Revenues	103,746,048.86	102,853,016.39	893,032.47	0.87
Fuel for Electric Generation	27,726,784.09	27,771,256.76	(44,472.67)	(0.16)
Power Purchased	14,988,604.35	16,677,942.77	(1,689,338.42)	(10.13)
Other Operation Expenses	17,025,606.16	14,546,134.56	2,479,471.60	17.05
Maintenance	9,089,599.96	9,060,122.70	29,477.26	0.33
Depreciation	10,809,368.57	10,361,641.07	447,727.50	4.32
Amortization Expense	525,416.58	441,306.93	84,109.65	19.06
Regulatory Credits	(208,010.82)	(198,312.01)	(9,698.81)	(4.89)
Taxes				
Federal Income	4,989,297.46	6,116,985.07	(1,127,687.61)	(18.44)
State Income	909,902.28	1,115,559.59	(205,657.31)	(18.44)
Deferred Federal Income - Net	125,072.31	-	125,072.31	100.00
Deferred State Income - Net	22,809.54	-	22,809.54	100.00
Property and Other	1,464,618.61	2,069,113.47	(604,494.86)	(29.22)
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	183,265.83	173,563.02	9,702.81	5.59
Total Operating Expenses	87,652,334.92	88,135,313.93	(482,979.01)	(0.55)
Net Operating Income	16,093,713.94	14,717,702.46	1,376,011.48	9.35
Other Income Less Deductions				
Other Income Less Deductions	(603,466.59)	117,128.49	(720,595.08)	(615.22)
AFUDC - Equity	(11,601.23)	540,799.74	(552,400.97)	(102.15)
Total Other Income Less Deductions	(615,067.82)	657,928.23	(1,272,996.05)	(193.49)
Income Before Interest Charges	15,478,646.12	15,375,630.69	103,015.43	0.67
Interest on Long-Term Debt	6,333,688.35	5,855,815.54	477,872.81	8.16
Amortization of Debt Expense - Net	68,395.59	67,639.57	756.02	1.12
Other Interest Expenses	274,485.97	265,717.07	8,768.90	3.30
AFUDC - Borrowed Funds	(81,138.25)	(161,959.30)	80,821.05	49.90
Total Interest Charges	6,595,431.66	6,027,212.88	568,218.78	9.43
Net Income	8,883,214.46	9,348,417.81	(465,203.35)	(4.98)

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2010

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	484,271,380.80	464,299,204.43	19,972,176.37	4.30
Rate Refunds	(987,769.21)	-	(987,769.21)	(100.00)
Total Operating Revenues	483,283,611.59	464,299,204.43	18,984,407.16	4.09
Fuel for Electric Generation	153,910,834.48	142,918,502.95	10,992,331.53	7.69
Power Purchased	68,990,949.38	80,574,232.18	(11,583,282.80)	(14.38)
Other Operation Expenses	67,479,076.42	63,634,761.13	3,844,315.29	6.04
Maintenance	32,016,469.15	86,424,500.03	(54,408,030.88)	(62.95)
Depreciation	43,134,728.55	42,311,119.13	823,609.42	1.95
Amortization Expense	2,247,432.51	1,569,054.72	678,377.79	43.23
Regulatory Credits	(826,491.91)	(787,817.08)	(38,674.83)	(4.91)
Taxes				
Federal Income	19,799,017.34	(3,252,709.72)	23,051,727.06	708.69
State Income	3,442,092.39	586,671.58	2,855,420.81	486.72
Deferred Federal Income - Net	6,735,680.77	3,879,162.60	2,856,518.17	73.64
Deferred State Income - Net	1,330,268.67	53,079.84	1,277,188.83	2,406.17
Property and Other	6,759,417.97	7,720,555.26	(961,137.29)	(12.45)
Investment Tax Credit	-	5,354,113.77	(5,354,113.77)	(100.00)
Loss (Gain) from Disposition of Allowances	(44,023.81)	(84,707.76)	40,683.95	48.03
Accretion Expense	727,398.35	688,825.77	38,572.58	5.60
Total Operating Expenses	405,702,850.26	431,589,344.40	(25,886,494.14)	(6.00)
Net Operating Income	77,580,761.33	32,709,860.03	44,870,901.30	137.18
Other Income Less Deductions				
Other Income Less Deductions	1,701,637.65	5,784,307.83	(4,082,670.18)	(70.58)
AFUDC - Equity	(47,973.00)	2,222,071.29	(2,270,044.29)	(102.16)
Total Other Income Less Deductions	1,653,664.65	8,006,379.12	(6,352,714.47)	(79.35)
Income Before Interest Charges	79,234,425.98	40,716,239.15	38,518,186.83	94.60
Interest on Long-Term Debt	25,479,747.52	23,333,863.14	2,145,884.38	9.20
Amortization of Debt Expense - Net	273,581.97	268,348.21	5,233.76	1.95
Other Interest Expenses	1,170,956.07	1,093,836.86	77,119.21	7.05
AFUDC - Borrowed Funds	(319,448.33)	(665,152.67)	345,704.34	51.97
Total Interest Charges	26,604,837.23	24,030,895.54	2,573,941.69	10.71
Net Income	52,629,588.75	16,685,343.61	35,944,245.14	215.42

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2010

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	1,376,630,410.24	1,420,760,099.14	(44,129,688.90)	(3.11)
Rate Refunds	(1,457,000.00)	-	(1,457,000.00)	(100.00)
Total Operating Revenues	1,375,173,410.24	1,420,760,099.14	(45,586,688.90)	(3.21)
Fuel for Electric Generation	444,689,645.48	500,152,509.02	(55,462,863.54)	(11.09)
Power Purchased	187,230,115.93	229,320,717.99	(42,090,602.06)	(18.35)
Other Operation Expenses	200,144,957.12	175,387,787.97	24,757,169.15	14.12
Maintenance	48,866,076.68	146,670,420.58	(97,804,343.90)	(66.68)
Depreciation	128,377,347.69	133,178,540.11	(4,801,192.42)	(3.61)
Amortization Expense	6,745,245.92	5,182,644.71	1,562,601.21	30.15
Regulatory Credits	(2,444,614.47)	(2,305,422.35)	(139,192.12)	(6.04)
Taxes				
Federal Income	18,285,371.83	18,581,536.70	(296,164.87)	(1.59)
State Income	4,486,927.95	6,928,514.01	(2,441,586.06)	(35.24)
Deferred Federal Income - Net	48,228,528.07	(2,835,781.92)	51,064,309.99	1,800.71
Deferred State Income - Net	9,179,838.46	(2,667,085.04)	11,846,923.50	444.19
Property and Other	19,995,475.53	21,783,696.09	(1,788,220.56)	(8.21)
Investment Tax Credit	16,062,341.26	27,421,011.74	(11,358,670.48)	(41.42)
Loss (Gain) from Disposition of Allowances	(44,023.81)	(84,707.76)	40,683.95	48.03
Accretion Expense	2,144,767.27	2,009,769.37	134,997.90	6.72
Total Operating Expenses	1,131,948,000.91	1,258,724,151.22	(126,776,150.31)	(10.07)
Net Operating Income	243,225,409.33	162,035,947.92	81,189,461.41	50.11
Other Income Less Deductions				
Other Income Less Deductions	2,050,461.81	26,527,564.53	(24,477,102.72)	(92.27)
AFUDC - Equity	1,635,852.72	6,370,562.02	(4,734,709.30)	(74.32)
Total Other Income Less Deductions	3,686,314.53	32,898,126.55	(29,211,812.02)	(88.79)
Income Before Interest Charges	246,911,723.86	194,934,074.47	51,977,649.39	26.66
Interest on Long-Term Debt	74,445,859.25	69,888,337.21	4,557,522.04	6.52
Amortization of Debt Expense - Net	820,372.10	769,408.79	50,963.31	6.62
Other Interest Expenses	3,406,104.54	4,891,504.31	(1,485,399.77)	(30.37)
AFUDC - Borrowed Funds	(1,031,812.30)	(2,066,415.09)	1,034,602.79	50.07
Total Interest Charges	77,640,523.59	73,482,835.22	4,157,688.37	5.66
Net Income	169,271,200.27	121,451,239.25	47,819,961.02	39.37

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

UPDATED Response to First Data Request of Commission Staff
Dated January 19, 2010

Updated Response filed May 27, 2010

Question No. 55

Responding Witness: Shannon L. Charnas

Q-55. Provide the following information concerning the costs for the preparation of this case:

a. A detailed schedule of expenses incurred to date for the following categories:

(1) Accounting;
(2) Engineering;
(3) Legal;
(4) Consultants; and
(5) Other Expenses (Identify separately).

For each category, the schedule should include the date of each transaction, check number or other document reference, the vendor, the hours worked, the rates per hour, amount, a description of the services performed, and the account number in which the expenditure was recorded. Provide copies of any invoices, contracts, or other documentation that support charges incurred in the preparation of this rate case. Indicate any costs incurred for this case that occurred during the test year.

b. An itemized estimate of the total cost to be incurred for this case. Expenses should be broken down into the same categories as identified in (a) above, with an estimate of the hours to be worked and the rates per hour. Include a detailed explanation of how the estimate was determined, along with all supporting workpapers and calculations.

c. During the course of this proceeding, provide monthly updates of the actual costs incurred, in the manner requested in (a) above. Updates will be due the last business day of each month, through the month of the public hearing.

A-55. c. See attached.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Schedule of Rate Case Preparation Costs

Response to Commission's Order
Dated January 19, 2010

Question No. 55(c)

Responding Witness: Shannon L. Charnas

Date	Invoice #	Vendor Name	Hours	Rate/Hr	Amount	Description	Account
31-Mar-10	646171	STOLL KEENON OGDEN PLLC	56.9	$ 229.57	$ 13,062.28	Professional Services	186023
15-Apr-10	1	J BRUCE MILLER LAW GROUP	21.0	250.00	5,250.00	Professional Services	186023
		SUBTOTAL LEGAL OUTSIDE COUNSEL KU ELECTRIC			18,312.28		186023
		TOTAL LEGAL OUTSIDE COUNSEL KU ELECTRIC @ 04/30/2010			116,891.76		186023
		TOTAL LEGAL OUTSIDE COUNSEL KU ELECTRIC			**135,204.04**		186023
5-Mar-10	134010009922	MERCER US INC			92.00	Pension, post-retirement and post-employment projections	186023
2-Apr-10	401032	THE PRIME GROUP LLC	127.8	191.49	24,462.50	Cost of service and rate design development	183023
		SUBTOTAL CONSULTANTS KU ELECTRIC			24,554.50		186023
		TOTAL CONSULTANTS KU ELECTRIC @ 04/30/2010			93,735.50		186023
		TOTAL CONSULTANTS KU ELECTRIC			**118,290.00**		186023
6-Mar-10	109652167	XEROX CORP			13,071.92	Reprographic services	186023
6-Mar-10	109652169	XEROX CORP			238.98	Reprographic services	186023
		SUBTOTAL SUPPLIES/SERVICES - OTHER KU ELECTRIC			13,310.90		186023
		TOTAL SUPPLIES/SERVICES - OTHER KU ELECTRIC @ 04/30/2010			1,463,147.52		186023
		TOTAL SUPPLIES/SERVICES - OTHER KU ELECTRIC			**1,476,458.42**		186023
		TOTAL RATE CASE EXPENSES @ 04/30/2010			**$ 1,729,952.46**		186023

40033

Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202-2828
502 333-6000
Tax ID # 61-0421389

RECEIVED
APR 05 2010
LAW DEPARTMENT

E.ON U.S. LLC
Attn: Dorothy E O'Brien
220 West Main Street
Louisville, KY 40202

March 31, 2010
Invoice #: 646171
Account #: 400001/134411

Please send your payment by April 30, 2010 to Stoll Keenon Ogden PLLC at:
P.O. Box 11969
Lexington, KY 40579-1969

Re: 2009 KY Base Rate Case
Your Reference: Responsible Attorney: Allyson Sturgeon
eCounsel No. 27749

RECEIVED
APR 21 2010
ACCOUNTS PAYABLE

Fees rendered this bill	$ 28,726.00
Less E.ON special discount	$-2,872.60
Disbursements	$ 271.17
Total Current Charges This Matter	**$ 26,124.57**

125973	KU RATECASE 2010	0321	026900 =	13062.28
125974	LGE RC-GS 2010	0321	026900 =	4754.67
125975	LGE RC-EL 2010	0321	026900 =	8307.62
				26124.57

Keep this copy for your records.

E.ON U.S. LLC

Stoll Keenon Ogden PLLC
Invoice No. 646171

Professional Services for the period through 02/28/10, including the following:

Re: 2009 KY Base Rate Case
Your Reference: Responsible Attorney: Allyson Sturgeon
eCounsel No. 27749

Our Reference: 400001/134411/KRR/1016

Date	Description	Tkpr	Hours
02/01/10	Meeting at E.ON with Ms. Sturgeon and others re electronic discovery issues.	KRR	1.00
02/02/10	Check regulations dealing with newspaper notice for utilities; respond to Ms. Sturgeon's email re reasons for seeking redundancy in newspaper notices	DTE	0.60
02/02/10	Work on discovery responses.	KRR	1.00
02/02/10	Draft of confidential protection petition; research therefor.	WDC	1.60
02/03/10	Researching refunds for interim rates	MLB	2.60
02/03/10	Revisions to draft data responses.	WDC	1.20
02/04/10	Attend meetings at E.ON with client re data response issues of salaries and benefits; review of draft data responses.	KRR	6.00
02/05/10	Prepare for and attend meetings at E.ON with client re review draft data responses.	KRR	4.50
02/05/10	Draft of petition for confidential protection.	WDC	1.50
02/08/10	Attention to discovery matters.	KRR	0.50
02/08/10	Research for confidentiality petitions re disclosure of W-2 information; call with Ms. Sturgeon re brief.	WDC	3.00
02/09/10	Attend meetings at E.ON and review draft data responses.	KRR	4.30
02/09/10	Draft of brief outline.	WDC	0.70
02/10/10	Examine professional services spreadsheet re LG&E discovery issues	RMW	1.00
02/10/10	Review and analysis of schedules for data responses.	WDC	6.60
02/11/10	Attention to discovery issues.	KRR	0.30
02/11/10	Drafting outline of rate case brief	MLB	4.60
02/11/10	Examine spreadsheet re KU professional services re dicovery issues; e-mail re same	RMW	1.00
02/12/10	Attention to discovery issues.	KRR	0.50
02/12/10	Drafting outline for rate case brief	MLB	3.90

Date	Description	Tkpr	Hours
02/12/10	Review of data response 1-31.	WDC	1.30
02/13/10	Draft of response to Granderson motion to intervene.	WDC	1.30
02/14/10	Revisions to draft brief outline.	WDC	0.80
02/15/10	Attention to discovery issues.	KRR	1.00
02/15/10	Drafting the rate case brief	MLB	3.80
02/15/10	Examine brief outline and response to Granderson motion to intervene and e-mail re same	RMW	0.80
02/15/10	Revisions to draft brief outline; revisions to draft response to Granderson petition.	WDC	1.40
02/16/10	Attention to procedural order.	KRR	0.20
02/16/10	Drafting rate case brief	MLB	6.60
02/16/10	Draft of response to Lookofsky motion to intervene.	WDC	0.40
02/17/10	Drafting the rate case brief	MLB	3.90
02/18/10	Meeting at E.ON with Ms. Sturgeon and others re discovery issues.	KRR	1.00
02/18/10	Drafting the rate case brief	MLB	3.90
02/18/10	Meeting re rate case discovery.	WDC	1.50
02/19/10	Conference with Ms. Sturgeon re procedural and discovery issues.	KRR	0.60
02/19/10	Drafting the rate case brief	MLB	2.50
02/22/10	Work on discovery issues.	KRR	2.00
02/22/10	Drafting the rate case brief	MLB	3.90
02/22/10	Revisions to draft brief.	WDC	0.40
02/23/10	Attention to motions for intervention and procedural issues.	KRR	1.00
02/23/10	Drafting rate case brief	MLB	0.10
02/23/10	Draft of brief; communications with client and AG re confidentiality agreement.	WDC	1.40
02/24/10	Work on discovery issues.	KRR	3.00
02/24/10	Analysis re KU newspaper notice issue	RMW	0.50
02/24/10	Review of, and revisions to, completed notice filings; research re substantial compliance.	WDC	5.70
02/25/10	Attention to motions for intervention and procedural issues.	KRR	1.40

Date	Description	Tkpr	Hours
02/25/10	Research re issues in notice.	WDC	5.20
02/26/10	Attention to motions for intervention and procedural issues.	KRR	2.50
02/26/10	Drafting the rate case brief	MLB	6.00
02/26/10	Receive and examine e-mail re KU notice	RMW	0.30
02/26/10	Meeting at E.ON re ZyLab/discovery procedures; research re issues in notice.	WDC	3.00

Total Services **$28,726.00**

Summary of Services

Init	Timekeeper	Hours	Rate	Value
RMW	Watt, R M	3.60	350.00	1,260.00
DTE	Eversole, D T	0.60	310.00	186.00
MLB	Braun, Monica	41.80	200.00	8,360.00
KRR	Riggs, Kendrick R.	30.80	350.00	10,780.00
WDC	Crosby III, W D	37.00	220.00	8,140.00
	Total Services	113.80		$28,726.00

Disbursements

Date	Description	Tkpr	Amount
01/26/10	Mileage to PSC VENDOR: Sallee, Kimberly M; INVOICE#: 020510; DATE: 2/5/2010		$57.50
02/08/10	Lexis Charges	WDC	$64.41
02/09/10	2/9 parking VENDOR: Riggs, Kendrick R; INVOICE#: 021910; DATE: 2/19/2010	KRR	$8.00
02/11/10	Telephone Expense 1(502)564-3940; 1 Mins.	KRR	$0.19
02/11/10	Telephone Expense 1(502)564-3940; 2 Mins.	KRR	$0.38
02/16/10	Duplicating Charges		$7.20
02/16/10	Duplicating Charges		$7.20
02/16/10	2/16 KPSC VENDOR: Campbell, Michael; INVOICE#: 021910; DATE: 2/19/2010	MC	$29.00
02/17/10	Westlaw Charges	MLB	$13.15
02/19/10	Telephone Expense 1(513)421-2255; 1 Mins.	KRR	$0.19
02/23/10	Telephone Expense 1(502)564-3940; 11 Mins.	EKC	$2.09
02/24/10	Duplicating Charges		$13.60
02/24/10	Lexis Charges	WDC	$3.33
02/24/10	2/24 PSC Frankfort VENDOR: Campbell, Michael; INVOICE#: 030510; DATE: 3/5/2010	MC	$57.50
02/25/10	Telephone Expense 1(513)421-2255; 2 Mins.	KRR	$0.38
02/25/10	Telephone Expense 1(502)696-5454; 2 Mins.	KRR	$0.38
02/25/10	Lexis Charges	WDC	$6.67

Total Disbursements **$271.17**

Summary of Disbursements

Disb Code	Description	Amt
002	Duplicating Charges	$28.00
005	Telephone Expense	$3.61
021	lodging, parking and etc.	$8.00
022	Westlaw Charges	$13.15
041	long distance transportation, mileage	$144.00
054	Lexis Charges	$74.41
	Total Disbursements	$271.17

TOTAL FEES & DISBURSEMENTS	$28,997.17
LESS DISCOUNT	$-2,872.60
Total Current Charges This Matter	**$26,124.57**

J. Bruce Miller Law Group

605 West Main Street
Louisville, Kentucky 40202-2921

J. Bruce Miller

Telephone: (502) 587-0900
Telecopier: (502) 587-9008
Email: jbm@jbmlg.com

APR 19 2010

Allyson K. Sturgeon, Senior Corporate Attorney
E. On U.S., LLC
Corporate Law Department
220 W. Main St.
P.O. Box 32030
Louisville, Kentucky 40232

April 15, 2010
Client No. 2485

Re: Bill for Services Rendered from March 16 – April 15, 2010

Dear Allyson:

Enclosed please find our initial bill for services rendered during the time frame from March 16th to April 15th of 2010. There are no expenses to be reimbursed.

Please advise me, a.s.a.p., if this billing is not in accordance with E.On U.S.'s expectations regarding format, etc., as I do not want to cause any delay in getting this billing in line for payment.

Of course, if there are any problems with the format, etc., I'll be pleased to correct them immediately.

Many thanks and I look forward to receiving the Intervenor's Testimony upon its receipt by you all.

Personal regards,

J. BRUCE MILLER

cc. billing file.

Vendor 14515

APR 19 2010

J. Bruce Miller Law Group

605 West Main Street
Louisville, Kentucky 40202-2921

J. Bruce Miller

Telephone: (502) 587-0900
Telecopier: (502) 587-9008
Email: jbm@jbmlg.com

Allyson K. Sturgeon, Senior Corporate Attorney
E. On U.S., LLC
Corporate Law Department
220 W. Main St.
P.O. Box 32030
Louisville, Kentucky 40232

April 15, 2010
Client No. 2485

Invoice #1

Re: ***In re: Application of Louisville Gas & Electric Company for an Adjustment of Electric and Gas Rates,* Case No. 2009-00549**

***In re: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2009000548**

FOR LEGAL SERVICES RENDERED: 03/16/10 thru 04/15/10

TOTAL SERVICES	42.00	$10,500.00

125973	KU RATECASE 2010	0321	026900 =	5250.00
125974	LGE RC-GS 2010	0321	026900 =	1911.00
125975	LGE RC-EL 2010	0321	026900 =	3339.00
				10500.00

Vendor 14215

APR 19 2010

J. Bruce Miller Law Group

605 West Main Street
Louisville, Kentucky 40202-2921

J. Bruce Miller

Telephone: (502) 587-0900
Telecopier: (502) 587-9008
Email: jbm@jbmlg.com

Allyson K. Sturgeon, Senior Corporate Attorney
E. On U.S., LLC
Corporate Law Department
220 W. Main St.
P.O. Box 32030
Louisville, Kentucky 40232

April 15, 2010
Client No. 2485

Invoice #1

Re: *In re: Application of Louisville Gas & Electric Company for an Adjustment of Electric and Gas Rates*, **Case No. 2009-00549**

In re: Application of Kentucky Utilities Company for an Adjustment of Base Rates, **Case No. 2009000548**

FOR LEGAL SERVICES RENDERED: 03/16/10 thru 04/15/10

Date	*Atty*	*Description of Service*	*Time*	*Amount*
03/16/10	JBM	11:00 a.m. to 11:30 a.m.: r/rev/assess Ltr of Engagement and LGE outside counsel rules; Ph. to/fr. Allyson Sturgeon re: same.	0.50	$125.00
		1:45 p.m. to 2:45 p.m.: Locate prior records from Archives; instx to BAG to retrieve same	1.00	250.00
03/17/10	JBM	8:30 a.m. to 9:00 a.m.: to LGE for files in current rate cases and return to office	0.50	125.00
		10:45 a.m. to noon; 1:00 p.m. to 6:30 p.m.; read archived files of case 2003-433; Stafferi, Beer, Rives and Murphy testimony; r/rev 9/3/96 ltr to McCall re: our review and recommendations Re: whether LGE should seek gas rate increase r/rev/assess notes in preparation for practice session in cross examination	6.75	1,687.50
03/18/10	JBM	8:00 a.m. to 9:15 a.m.: Finish reading prior testimony in Case 2003-433	1.25	312.50

		10:00 a.m. to 12:15 p.m.: Begin reading and marking Vol I, current case 549; Statutory Notice Application; Financial Exhibits and Filing Requirements 1-7	2.25	562.50
		7:00 p.m. to 9:30 p.m.: Vol I, Case 549 read rev/assess Filing Requirements 8-9	2.50	625.00
03/19/10	JBM	10:15 a.m. to noon: close re-exam of Section 7 of Gas Tariff in rate case 549 by Lonnie Bellar.	1.75	437.50
03/21/10	JBM	1:30 p.m. to 5:15 p.m.: Read/review/underline/ highlight direct testimony in rate case 549, Volume 4 by Stafferi, Thompson, Hermann, Rives, Scott and Charnas.	3.75	937.50
03/22/10	JBM	9:15 a.m. to 12:15 p.m. and 2:00 p.m. to 4:00 p.m.: Read/review/underline highlight direct testimony in rate case 549 Volume 4 of Miller, Arbough, Avera, Bellar, Conroy and Wolfram.	5.00	1,250.00
03/23/10	JBM	3:30 p.m. to 5:45 p.m.: Complete work of yesterday in Volume 4	2.25	562.50
03/24/10	JBM	10:30 a.m. to noon: Begin read/review/underline Vol 5 in rate case 549: Seelye testimony	1.50	375.00
03/25/10	JBM	12:15 p.m. to 3:00 p.m.: Continue read/review of Vol. 5/Seelye testimony in case 549	2.75	687.50
03/26/10	JBM	12:30 p.m. to 3:00 p.m.: Complete read/review of Vol 5/Seelye testimony in case 549	2.50	625.00
	JBM	3:45 p.m. to 5:30 p.m.: Verify that Stafferi Testimony is same in Case 548 as it was in Case 549; and verify that Thompson Testimony		

		Is same in Case 548 as it was in Case 549	1.75	437.50
03/29/10	JBM	3:45 p.m. to 5;00 p.m.: Verify that Hermann Testimony is same in Case 548 as it was in Case 549 and *begin* noting differences in Rives' Testimony in Case 548 vs. his Testimony in 549	1.25	312.50
03/30/10	JBM	9:30 a.m. to 11:45 a.m.: Continue to a completion noting the differences in Rives' Testimony in Case 548 vs. his Testimony in 549.	2.25	562.50
04/01/10	JBM	9:15 a.m. to 11:45 a.m.: Re-organize files received and email to Allyson Sturgeon re: Intervenor's Testimony date due; Quick review of work and store awaiting Receipt of Intervenor's testimony	2.50	625.00
TOTAL SERVICES			42.00	$10,500.00

Expenses: 03/16/10 – 04/15/10

1.	Xeroxing	0	
2.	Lexis-Nexis Computer Research	0	0

Total Services/Expenses 03/16/10 – 04/15/10 **$10,500.00**

Balance remaining under contract	**$50,000.00**	
	(10,500.00)	**39,500.00**

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

462 South Fourth Street, Suite 1100
Louisville, KY 40202
502 561 4710
henry.erk@mercer.com
www.mercer.com

Memo

To: Heather Metts
Date: May 26, 2010
From: Henry Erk
Subject: Fees Related to the Pension Cost Projections for Rate Case

For February, 2010, Mercer's consulting and actuarial fees related to pension cost projections for the rate case were $184.

The Prime Group

Invoice for Services Rendered

Invoice Date: April 2, 2010

Invoice Number 40103-2

To: E.ON
P.O. Box 32010
Louisville, KY 40232

Attn: Mr. Robert Conroy

212.0 hours of consulting work by Steve Seelye @ $200.00/hr performed during March in responding to data requests and providing support for a retail rate case for LG&E and KU in Kentucky for E.ON.	$ 42,400.00
29.5 hours of consulting work by Jeff Wernert @ $150.00/hr performed during March in responding to data requests and providing support for a retail rate case for LG&E and KU in Kentucky for E.ON.	$ 4,425.00
14.0 hours of consulting work by Paul Garcia @ $150.00/hr performed during March in responding to data requests and providing support for a retail rate case for LG&E and KU in Kentucky for E.ON.	$ 2,100.00
Total due for March	$ 48,925.00

4/13/10

Please remit payment to: **The Prime Group, LLC**
P.O. Box 837
Crestwood, KY 40014-0837

Ky Rate Case 2010

PO# 35361

RECEIVED
APR 1 4 2010
ACCOUNTS PAYABLE

Line 4 (KU RC) - $ 24,462.50
Line 5 (LG&E Elec RC) - $ 15,558.15
Line 6 (LG&E Gas RC) - $ 8,904.35

Complete

XEROX CAPITAL SVCS 0981
SUITE 500
9100 KEYSTONE CROSS
INDIANAPOLIS, IN
46240

Telephone 800-854-3689
Direct Billing Inquiries To:

706775764
Customer No.

109652167
Invoice No.

03/06/10
Invoice Date

xerox

Purchase Order No.

03/04/10
Date

GSA Contract No.

X551440
Xerox Reference No.

03/04/10
Date Processed

Registration No.

MW
Special Reference No.

Tax

PAYABLE ON RECPT
Terms of Payment

Ship To
LOUISVILLE GAS AND
ELECTRIC CO
LG & E ENERGY SVCS
820 W BROADWAY
LOUISVILLE KY
40202

Bill To
LG & E ENERGY LLC
SUITE 1400
220 W MAIN ST
LOUISVILLE KY
40202-1395

7022030
Master Order No.

Bill Code

ENTERED 4/5/10 JM

REMARKS
THANK YOU FOR YOUR BUSINESS
ATTN: ACCOUNTS PAYABLE DEPARTMENT
MONTHLY MINIMUM - OVERAGES

Reorder No.	Description	Quantity Ordered	Quantity Shipped	Unit Price	Amount
	MANAGEMENT OFFICE SVCS *		1	12287.6600	12,287.66
	MAIL SERVICES MINIMUM *		1	24671.9100	24,671.91
	PRODUCTION MAIL SVCS *		1	37259.6600	37,259.66
	SHUTTLE SERVICE MINIMUM*		1	3622.8400	3,622.84
	REPROGRAPHICS CLR SVC *		1	49430.7500	49,430.75
	DOCUMENT MNGMNT SVCS *		1	11822.6700	11,822.67
	SERVICE HELP DESK MIN *		1	3622.8400	3,622.84
	B/W OVERAGE : 1629272 X* .0041		1	6680.0152	6,680.02
	COLOR OVERAGE *		172162	.0837	14,409.96
	B/W ON COLOR OVERAGE *		4323	.0137	59.23
	SUPPLIES : 238.6 X 1 *		1	238.6000	238.60
	IPROCUREMENT NON-XEROX * : 1421.62 X 1		1	1421.6200	1,421.62

INVOICE TOTAL (\$) 165,527.76

Rate Case
KU -\$13071.92
LGEE -\$8313.75
LGEG -\$4758.18
\$26143.85

RECEIVED
APR 0 1 2010
ACCOUNTS PAYABLE

SPO # 12587 Release # 207
03/31/2010
M. Moman-Sol

THANK YOU FOR DOING BUSINESS WITH XEROX BUSINESS SERVICES

TO ORDER SUPPLIES CALL TOLL FREE 1-800-822-2200

PLEASE INCLUDE THIS STUB WITH YOUR PAYMENT, OR WRITE YOUR INVOICE NUMBER(S) ON YOUR CHECK.

Ship To/Installed At
LOUISVILLE GAS AND
ELECTRIC CO
LG & E ENERGY SVCS
820 W BROADWAY
LOUISVILLE KY
40202

Bill To
LG & E ENERGY LLC
SUITE 1400
220 W MAIN ST
LOUISVILLE KY
40202-1395

When Paying By Mail
Send Payment To:
XEROX CORPORATION
P O BOX 650361
DALLAS, TX
75265-0361

☐ Please check here if your "Bill To" address or "Ship To/Installed At" location has changed and complete reverse side.

Invoice Amount
\$165,527.76

00-495-2826 1 706775764 109652167 03/06/10 428D

038 161110490 B
Q000155

S734 1 LGE00

X X

20210000807006 0 1096521671 0300000009 270677576494

Complete

Customer Information

XEROX CAPITAL SVCS 0897
SUITE 500
9100 KEYSTONE CROSS
INDIANAPOLIS, IN
46240
Telephone 800-854-3689
Direct Billing Inquiries To:

Customer No.	Invoice No.	Invoice Date	
706775772	109652169	03/06/10	xerox

Purchase Order No.	Date	GSA Contract No.
	~~03/04/10~~	

Xerox Reference No.	Date Processed	Registration No.
X551441	03/04/10	

Special Reference No.	Tax	Terms of Payment
MW		PAYABLE ON RECPT

Ship To
KENTUCKY UTILITIES
COMPANY
LG & E ENERGY SVCS
1 QUALITY ST
LEXINGTON KY
40507

Bill To
LOIUSVILLE GAS
AND ELECTRIC COMPANY
SUITE 1400
220 W MAIN ST
LOUISVILLE KY
40202-1395

Master Order No. 7022030
Bill Code

ENTERED 4/5/10 JM

REMARKS
THANK YOU FOR YOUR BUSINESS
ATTN: ACCOUNT PAYABLE
MONTHLY MINIMUM - OVERAGES

Reorder No.	Description	Quantity Ordered	Quantity Shipped	Unit Price	Amount
	MONTHLY MINIMUM		1	399.0000	399.00
	B/W USAGE		2575	.0041	10.56
	COLOR USAGE		5632	.0837	471.40
	INVOICE TOTAL				$880.96

Invoice

Rate Case
KU -$238.98
LGEE $151.99
LGEG -$86.99
$477.96

SPO # 12587 Release # 207
03/31/2010
M. Morrison-Soule

RECEIVED
APR 01 2010
ACCOUNTS PAYABLE

THANK YOU FOR DOING BUSINESS WITH XEROX BUSINESS SERVICES

TO ORDER SUPPLIES CALL TOLL FREE 1-800-822-2200

PLEASE INCLUDE THIS STUB WITH YOUR PAYMENT, OR WRITE YOUR INVOICE NUMBER(S) ON YOUR CHECK.

Payment

Ship To/Installed At
KENTUCKY UTILITIES
COMPANY
LG & E ENERGY SVCS
1 QUALITY ST
LEXINGTON KY
40507

Bill To
LOIUSVILLE GAS
AND ELECTRIC COMPANY
SUITE 1400
220 W MAIN ST
LOUISVILLE KY
40202-1395

When Paying By Mail Send Payment To:
XEROX CORPORATION
P O BOX 650361
DALLAS, TX
75265-0361

☐ Please check here if your "Bill To" address or "Ship To/Installed At" location has changed and complete reverse side.

Invoice Amount
$880.96

00-495-2826 1 706775772 109652169 03/06/10 428D
038 160670470 B
Q000157
S734 1 LGE00
X X

202100008070060 1096521699 0300880966 270677577240

Customer Information

XEROX CAPITAL SVCS 0961
SUITE 500
9100 KEYSTONE CROSS
INDIANAPOLIS, IN
46240
Telephone 800-854-3689
Direct Billing Inquiries To:

706775764 Customer No.	109652168 Invoice No.	03/06/10 Invoice Date	xerox
Purchase Order No.	03/04/10 Date	GSA Contract No.	
X551440 Xerox Reference No.	03/04/10 Date Processed	Registration No.	
MW Special Reference No.	Tax	PAYABLE ON RECPT Terms of Payment	

Ship To
LOUISVILLE GAS AND
ELECTRIC CO
LG & E ENERGY SVCS
820 W BROADWAY
LOUISVILLE KY
40202

Bill To
LG & E ENERGY LLC
SUITE 1400
220 W MAIN ST
LOUISVILLE KY
40202-1395

7022030
Master Order No

Bill Code

REMARKS

Reorder No.	Description		Quantity Ordered	Quantity Shipped	Unit Price	Amount
	THIRD PARTY COURIER : 46982.04 X 1	*		1	46982.0400	46,982.04
	NATIONAL ENVELOPE : 68388.9 X 1	*		1	68388.9000	68,388.90
RATE CASE WORK	OVERTIME WEEKDAY	*		207	36.0000	7,452.00
	OVERTIME WEEKEND : 235.5 X 48	*		1	11304.0000	11,304.00
			INVOICE TOTAL			$134,126.94

Invoice

SPO # 12587 Release # 257
03 / 31 /2010
[illegible signature]

THANK YOU FOR DOING BUSINESS WITH XEROX BUSINESS SERVICES

TO ORDER SUPPLIES CALL TOLL FREE 1-800-822-2200

PLEASE INCLUDE THIS STUB WITH YOUR PAYMENT, OR WRITE YOUR INVOICE NUMBER(S) ON YOUR CHECK.

Ship To/Installed At
LOUISVILLE GAS AND
ELECTRIC CO
LG & E ENERGY SVCS
820 W BROADWAY
LOUISVILLE KY
40202

Bill To
LG & E ENERGY LLC
SUITE 1400
220 W MAIN ST
LOUISVILLE KY
40202-1395

When Paying By Mail
Send Payment To:
XEROX CORPORATION
P O BOX 650361
DALLAS, TX
75265-0361

Payment

☐ **Please check here if your "Bill To" address or "Ship To/Installed At" location has changed and complete reverse side.**

Invoice Amount
$134,126.94

00-495-2826 1 706775764 109652168 03/06/10 428D
038 161110490 B
Q000156
S734 1 LGE00
X X

202100008070060 1096521680 0300000009 270677576498

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

UPDATED Response to Attorney General's Initial Requests for Information Dated March 1, 2010

Updated Response filed May 27, 2010

Question No. 188

Responding Witness: Valerie L. Scott

Q-188. Please provide copies of the financial statements (balance sheet, income statement, statement of cash flows, and the notes to the financial statements) for KU, E.ON U.S. LLC, and E.ON AG for the past 2007 and 2008. Please include 2009 financial statements when they become available. Please provide copies of the financial statements in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-188. The E.ON U.S. LLC 2009 financial statements are attached.

E.ON U.S. LLC and Subsidiaries

Consolidated Financial Statements

As of and for the Years Ended
December 31, 2009 and 2008

E.ON U.S. LLC and Subsidiaries
Consolidated Financial Statements
As of and for the Years Ended
December 31, 2009 and 2008

Table of Contents

E.ON U.S. LLC and Subsidiaries
Consolidated Financial Statements
As of and for the Years Ended
December 31, 2009 and 2008

Index of Abbreviations

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
Big Rivers	Big Rivers Electric Corporation
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Capital Corp.	E.ON U.S. Capital Corp.
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Centro	Distribuidora de Gas Del Centro S.A.
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	E.ON U.S. LLC and Subsidiaries
CT	Combustion Turbine
Cuyana	Distribuidora de Gas Cuyana S.A.
DOE	U.S. Department of Energy
DSM	Demand Side Management
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON Spain	E.ON Espana S.L.
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. Services Inc.
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
GAAP	Generally Accepted Accounting Principles
GAC	Group Annuity Contract
GHG	Greenhouse Gas
GSC	Gas Supply Clause
IBEW	International Brotherhood of Electrical Workers
ICSID	International Council for the Settlement of Investment Disputes
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LEM	LG&E Energy Marketing Inc.
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offered Rate
MISO	Midwest Independent Transmission System Operator

Index of Abbreviations (Cont.)

MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
Mw	Megawatts
NAAQS	National Ambient Air Quality Standards
NGHH	Natural Gas-Henry Hub
NOV	Notice of Violation
NOx	Nitrogen Oxide
OCI	Other Comprehensive Income (Loss) or Accumulated Other Comprehensive Income (Loss)
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PUHCA	Public Utility Holding Company Act
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard and Poor's Rating Service
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
Trimble County	LG&E's Trimble County plant
USWA	United Steelworkers of America
VDT	Value Delivery Team
VEBA	Voluntary Employee Beneficiary Association
Virginia Commission	Virginia State Corporation Commission
WKE	Western Kentucky Energy Corp. and its Affiliates

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Operations
(Millions of $)

	Years Ended December 31	
	2009	2008
Operating revenues:		
Electric utility	$2,145	$2,221
Gas utility	354	452
Non-utility	2	2
Total revenues	2,501	2,675
Operating expenses:		
Fuel and power purchased	949	1,053
Gas supply expenses	237	349
Utility operation and maintenance	607	533
Non-utility operation and maintenance	26	30
Depreciation, accretion and amortization (Note 1)	271	265
Total operating expenses	2,090	2,230
Loss on impairment of goodwill (Note 2)	(1,493)	(1,806)
Operating loss	(1,082)	(1,361)
Equity in earnings of unconsolidated venture	-	29
Mark-to-market income (expense) (Note 6)	18	(37)
Other income (deductions)	5	17
Interest expense - affiliated companies	(155)	(138)
Interest expense	(21)	(46)
Loss from continuing operations, before income taxes	(1,235)	(1,536)
Income tax expense (Note 10)	82	78
Loss from continuing operations	(1,317)	(1,614)
Discontinued operations (Note 3):		
Loss from discontinued operations before tax	(222)	(287)
Income tax benefit from discontinued operations	71	114
Loss from discontinued operations before noncontrolling interest	(151)	(173)
Loss on disposal of discontinued operations before tax	(114)	-
Income tax benefit from loss on disposal of discontinued operations	45	-
Loss on disposal of discontinued operations	(69)	-
Net loss	(1,537)	(1,787)
Noncontrolling interest - income from discontinued operations	(5)	(8)
Net loss attributable to member	$(1,542)	$(1,795)

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

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Comprehensive Loss (Note 15)
(Millions of $)

	Years Ended December 31	
	2009	2008
Net loss	$(1,537)	$(1,787)
Other comprehensive income (loss):		
Defined-benefit pension and postretirement plans	29	(77)
Gains (losses) on derivative instruments	5	(2)
Foreign currency translation adjustment (Note 3)	(8)	(9)
Income tax (expense) benefit related to items of other comprehensive income	(11)	33
Comprehensive loss	(1,522)	(1,842)
Noncontrolling interest - income from discontinued operations	(5)	(8)
Other comprehensive income (loss) allocable to noncontrolling interest:		
Foreign currency translation adjustment (Note 3)	4	4
Income tax expense related to items of other comprehensive income	(1)	(1)
Comprehensive loss attributable to member	$(1,524)	$(1,847)

Consolidated Statements of Retained (Deficit) Earnings
(Millions of $)

	Years Ended December 31	
	2009	2008
Balance January 1	$(1,172)	$691
Net loss attributable to member	(1,542)	(1,795)
Cash dividends declared on common stock	(49)	(68)
Balance December 31	$(2,763)	$(1,172)

Consolidated Statements of Noncontrolling Interest
(Millions of $)

	Years Ended December 31	
	2009	2008
Balance January 1	$32	$34
Noncontrolling interest - income from discontinued operations	5	8
Distributions to noncontrolling interests - discontinued operations	(2)	(7)
Foreign currency translation adjustment	(3)	(3)
Balance December 31	$32	$32

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

E.ON U.S. LLC and Subsidiaries
Consolidated Balance Sheets
(Millions of $)

	December 31 2009	2008
Assets:		
Current assets:		
Cash and cash equivalents (Note 1)	$7	$15
Restricted cash (Note 1)	1	12
Accounts receivable:		
Customer - less reserve of $2 in 2009 and $4 in 2008 (Note 1)	286	331
Other - less reserve of $2 in 2009 and $1 in 2008	34	37
Materials and supplies (Note 1):		
Fuel (predominantly coal)	158	123
Gas stored underground	56	112
Other materials and supplies	72	68
Deferred income taxes (Note 10)	10	25
Assets of discontinued operations (Note 3)	90	920
Regulatory assets (Note 5)	46	75
Prepayments and other current assets	35	31
Total current assets	795	1,749
Utility plant, at original cost (Note 1):		
Electric	8,226	7,789
Gas	640	599
Common	226	190
Total utility plant, at original cost	9,092	8,578
Less: reserve for depreciation	3,546	3,414
Total utility plant, net	5,546	5,164
Construction in progress	1,599	1,551
Net utility plant	7,145	6,715
Other property and investments:		
Investment in unconsolidated venture (Note 1)	21	31
Other	5	11
Total other property and investments	26	42
Regulatory assets – pension and postretirement benefits (Notes 5 and 9)	309	387
Regulatory assets - other (Note 5)	242	153
Goodwill (Notes 1 and 2)	837	2,330
Other long-term assets	75	78
Total deferred debits and other assets	1,463	2,948
Total assets	$9,429	$11,454

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

E.ON U.S. LLC and Subsidiaries
Consolidated Balance Sheets (Continued)
(Millions of $)

	December 31 2009	December 31 2008
Liabilities and equity:		
Current liabilities:		
Current portion of long-term debt (Note 11)	$349	$349
Current portion of long-term debt - affiliated company (Notes 4 and 11)	358	255
Notes payable - affiliated company (Notes 4 and 12)	851	299
Accounts payable	221	298
Accounts payable - affiliated companies (Note 4)	43	57
Customer deposits	44	43
Liabilities of discontinued operations (Note 3)	7	1,006
Regulatory liabilities (Note 5)	41	40
Derivative liability	76	-
Other current liabilities	117	111
Total current liabilities	2,107	2,458
Long-term debt - affiliated companies (Notes 4 and 11)	3,063	2,766
Long-term debt (Note 11)	416	416
Total long-term debt	3,479	3,182
Deferred income taxes (Note 10)	87	435
Investment tax credit (Note 10)	152	130
Accumulated provision for pensions and related benefits (Note 9)	540	591
Asset retirement obligations (Note 5)	66	63
Regulatory liability - accumulated cost of removal (Note 5)	587	580
Regulatory liability - other (Note 5)	76	97
Derivative liability (Note 6)	28	55
Other long-term liabilities	83	66
Total deferred credits and other liabilities	1,619	2,017
Equity	2,224	3,797
Total liabilities and equity	$9,429	$11,454

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

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Cash Flows
(Millions of $)

	Years Ended December 31	
	2009	2008
Cash flows from operating activities:		
Net loss	$(1,537)	$(1,787)
Items not requiring cash currently:		
Depreciation, accretion and amortization	271	265
Deferred income taxes - net (Note 10)	46	(14)
Investment tax credit - net (Note 10)	(3)	(4)
Provision for pensions	83	41
Loss on impairment of goodwill (Note 2)	1,493	1,806
Undistributed earnings of unconsolidated ventures	11	1
Loss from discontinued operations – net of tax (Note 3)	225	181
(Gains) losses on interest-rate swaps	(33)	48
Other	(3)	(2)
Changes in certain net current assets and liabilities:		
Accounts receivable	73	1
Materials and supplies	31	(69)
Accounts payable	(64)	60
Accrued taxes and interest	(76)	(4)
Prepayments and other	(2)	(17)
Changes in other deferred credits	(2)	10
Change in storm restoration regulatory asset	(101)	(26)
Changes in other regulatory assets and liabilities	(12)	(10)
Changes in deferred income tax liabilities	11	12
Pension and postretirement funding	(51)	(18)
Net operating cash flows from discontinued operations	(580)	(69)
Other	16	(15)
Net cash flows (used) provided by operating activities	(204)	390
Cash flows from investing activities:		
Proceeds from sales of property	3	9
Construction expenditures	(703)	(931)
Construction expenditures - discontinued operations	(23)	(28)
Change in non-hedging derivative liability	7	(8)
Decrease in restricted cash	10	1
Net cash flows used by investing activities	(706)	(957)

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

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Cash Flows (Continued)
(Millions of $)

	Years Ended December 31	
	2009	2008
Cash flows from financing activities:		
Issuance of long-term debt (Note 11)	-	78
Retirement of long-term debt (Note 11)	-	(67)
Acquisition of outstanding bonds	-	(339)
Reissuance of reacquired bonds	-	159
Borrowings from affiliates (Notes 4 and 12)	2,090	2,637
Repayment of borrowings from affiliates (Notes 4 and 12)	(1,137)	(1,825)
Distributions to noncontrolling interests - discontinued operations	(2)	(7)
Payment of common dividends	(49)	(68)
Net cash flows provided by financing activities	902	568
Change in cash and cash equivalents	(8)	1
Beginning cash and cash equivalents	15	14
Ending cash and cash equivalents	$7	$15
Supplemental disclosures of cash flow information:		
Cash paid (received) during the year for:		
Income taxes	$(8)	$61
Interest on borrowed money - external	12	29
Interest on borrowed money - affiliates	149	134

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

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Capitalization
(Millions of $)

	December 31 2009	2008
Equity:		
Membership units, without par value -		
Authorized 10,000,000 units, outstanding		
1,001 units	$774	$774
Additional paid-in capital	4,224	4,224
Accumulated other comprehensive loss (Note 15)	(43)	(61)
Retained deficit	(2,763)	(1,172)
Total member's equity	2,192	3,765
Noncontrolling interest	32	32
Total equity	2,224	3,797
Long-term debt (Note 11):		
Louisville Gas and Electric Company:		
Pollution control series -		
Jefferson Co. 2001 Series A, due September 1, 2026, variable %	23	23
Trimble Co. 2001 Series A, due September 1, 2026, variable %	28	28
Jefferson Co. 2000 Series A, due May 1, 2027, 5.375%	25	25
Jefferson Co. 2001 Series A, due September 1, 2027, variable %	10	10
Jefferson Co. 2001 Series B, due November 1, 2027, variable %	35	35
Trimble Co. 2001 Series B, due November 1, 2027, variable %	35	35
Trimble Co. 2000 Series A, due August 1, 2030, variable %	83	83
Trimble Co. 2002 Series A, due October 1, 2032, variable %	42	42
Louisville Metro 2007 Series A, due June 1, 2033, 5.625%	31	31
Louisville Metro 2007 Series B, due June 1, 2033, variable %	35	35
Trimble Co. 2007 Series A, due June 1, 2033, 4.60%	60	60
Louisville Metro 2003 Series A, due October 1, 2033, variable %	128	128
Louisville Metro 2005 Series A, due February 1, 2035, 5.75%	40	40
Total LG&E bonds including reacquired bonds	575	575
Less reacquired bonds	163	163
Total LG&E bonds	412	412
Due to affiliates -		
Fidelia, due January 16, 2012, 4.33%, unsecured	25	25
Fidelia, due April 30, 2013, 4.55%, unsecured	100	100
Fidelia, due August 15, 2013, 5.31%, unsecured	100	100
Fidelia, due November 23, 2015, 6.48%, unsecured	50	50
Fidelia, due July 25, 2018, 6.21%, unsecured	25	25
Fidelia, due November 26, 2022, 5.72%, unsecured	47	47
Fidelia, due April 13, 2031, 5.93%, unsecured	68	68
Fidelia, due April 13, 2037, 5.98%, unsecured	70	70
Total LG&E due to affiliates	485	485
Total LG&E debt outstanding	897	897

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

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Capitalization (Continued)
(Millions of $)

	December 31 2009	December 31 2008
Long-term debt - cont. (Note 11):		
Kentucky Utilities Company:		
Pollution control series -		
Mercer Co. 2000 Series A, due May 1, 2023, variable %	13	13
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%	18	18
Carroll Co. 2002 Series A, due February 1, 2032, variable %	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable %	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable %	8	8
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %	2	2
Carroll Co. 2008 Series A, due February 1, 2032, variable %	78	78
Carroll Co. 2002 Series C, due October 1, 2032, variable %	96	96
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Carroll Co. 2006 Series B, due October 1, 2034, variable %	54	54
Trimble Co. 2007 Series A, due March 1, 2037, 6.00%	9	9
Total KU bonds	351	351
Due to affiliates -		
Fidelia, due November 24, 2010, 4.24%, unsecured	33	33
Fidelia, due January 16, 2012, 4.39%, unsecured	50	50
Fidelia, due April 30, 2013, 4.55%, unsecured	100	100
Fidelia, due August 15, 2013, 5.31%, unsecured	75	75
Fidelia, due December 19, 2014, 5.45%, unsecured	100	100
Fidelia, due July 8, 2015, 4.735%, unsecured	50	50
Fidelia, due December 21, 2015, 5.36%, unsecured	75	75
Fidelia, due October 25, 2016, 5.675%, unsecured	50	50
Fidelia, due April 24, 2017, 5.28%, unsecured	50	-
Fidelia, due June 20, 2017, 5.98%, unsecured	50	50
Fidelia, due July 25, 2018, 6.16%, unsecured	50	50
Fidelia, due August 27, 2018, 5.645%, unsecured	50	50
Fidelia, due December 17, 2018, 7.035%, unsecured	75	75
Fidelia, due July 29, 2019, 4.81%, unsecured	50	-
Fidelia, due October 25, 2019, 5.71%, unsecured	70	70
Fidelia, due November 25, 2019, 4.445%, unsecured	50	-
Fidelia, due February 7, 2022, 5.69%, unsecured	53	53
Fidelia, due May 22, 2023, 5.85%, unsecured	75	75
Fidelia, due September 14, 2028, 5.96%, unsecured	100	100
Fidelia, due June 23, 2036, 6.33%, unsecured	50	50
Fidelia, due March 30, 2037, 5.86%, unsecured	75	75
Total KU due to affiliates	1,331	1,181
Total KU debt outstanding	1,682	1,532

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

E.ON U.S. LLC and Subsidiaries
Consolidated Statements of Capitalization (Continued)
(Millions of $)

	December 31 2009	2008
Long-term debt - cont. (Note 11):		
E.ON U.S. Capital Corp.:		
Medium term notes, due November 1, 2011, 7.47%	2	2
Total Capital Corp. debt outstanding	2	2
E.ON U.S. LLC:		
Due to affiliates -		
Fidelia, due January 6, 2009, 3.98%, unsecured	-	50
Fidelia, due February 17, 2009, variable, unsecured	-	80
Fidelia, due November 26, 2009, variable, unsecured	-	50
Fidelia, due December 20, 2009, 4.07%, unsecured	-	75
Fidelia, due April 30, 2010, 4.64%, unsecured	150	150
Fidelia, due June 28, 2010, variable, unsecured	100	100
Fidelia, due October 15, 2010, 7.01%, unsecured	75	75
Fidelia, due January 6, 2011, 7.784%, unsecured	50	-
Fidelia, due July 5, 2011, variable, unsecured	300	300
Fidelia, due April 24, 2012, variable, unsecured	50	-
Fidelia, due November 19, 2012, variable, unsecured	75	75
Fidelia, due November 26, 2012, variable, unsecured	50	-
Fidelia, due December 19, 2012, 5.52%, unsecured	100	100
Fidelia, due December 21, 2012, variable, unsecured	100	-
Fidelia, due January 15, 2014, 6.044%, unsecured	75	-
Fidelia, due June 20, 2014, variable, unsecured	50	50
Fidelia, due June 23, 2014, variable, unsecured	50	-
Fidelia, due October 27, 2014, variable, unsecured	50	-
E.ON North America, due October 27, 2014, 4.63%, unsecured	50	50
Fidelia, due March 25, 2015, variable, unsecured	75	75
Fidelia, due February 17, 2016, variable, unsecured	80	-
Fidelia, due December 20, 2016, variable, unsecured	50	50
Fidelia, due April 25, 2017, 5.71%, unsecured	75	75
Total E.ON U.S. LLC debt outstanding	1,605	1,355
Total outstanding	4,186	3,786
Less current portion of long-term debt	707	604
Long-term debt	3,479	3,182
Total capitalization	$6,410	$7,583

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

Note 1 - Summary of Significant Accounting Policies

Basis of Presentation. E.ON U.S. is an indirect wholly-owned subsidiary of E.ON AG, a German corporation. The consolidated financial statements include the following companies: E.ON U.S., LG&E, KU, LEM, E.ON U.S. Services and Capital Corp., and their wholly owned subsidiaries. E.ON U.S.'s utility operations are comprised of LG&E and KU. E.ON AG and E.ON U.S. are registered as holding companies under PUHCA 2005 and were formerly registered holding companies under PUHCA 1935.

LG&E and KU are regulated public utilities engaged in the generation, transmission, distribution and sale of electric energy. LG&E also engages in the distribution and sale of natural gas. LG&E and KU maintain their separate identities and serve customers in Kentucky under their respective names. KU also serves customers in Virginia under the Old Dominion Power name, and it serves customers in Tennessee under the KU name.

Capital Corp. has been the primary holding company for the Company's non-utility businesses. Its businesses included:

- *WKE and affiliates*. WKE had a 25-year lease of and operated the generating facilities of Big Rivers, a power generation cooperative in western Kentucky, and a coal-fired facility owned by Henderson Municipal Power and Light, which is owned by the City of Henderson, Kentucky. The Company classified WKE as discontinued operations, and it terminated the WKE lease and disposed of the operations in July 2009. See Note 3, Discontinued Operations.

- *Argentine Gas Distribution*. Through its Argentine Gas Distribution operations, Capital Corp. owned interests in entities which distribute natural gas to approximately one million customers in Argentina through two distribution companies (Centro and Cuyana). The Company classified its Argentine Gas Distribution operations as discontinued operations effective December 31, 2009, and it sold the operations on January 1, 2010. See Note 3, Discontinued Operations.

E.ON U.S. Services provides services to affiliated entities, including E.ON U.S., LG&E, KU, Capital Corp. and LEM, at cost, as permitted under PUHCA 2005.

Consolidation. The consolidated financial statements of the Company include the accounts of the Company and its subsidiaries. All intercompany balances and transactions have been eliminated. Investments in business entities in which the Company does not have control, but has the ability to exercise significant influence over operating and financial policies, are accounted for by the equity method. The Company consolidates its investment in Centro and uses noncontrolling interests to reflect the portion of Centro not owned by the Company.

Goodwill. Testing of goodwill for impairment is carried out annually in the fourth quarter of each year or if changes in circumstances indicate that the value may be impaired, as required by the FASB ASC. This testing indicated an impairment of $1.493 billion in 2009 and $1.806 billion in 2008. See Note 2, Goodwill Impairment.

Regulatory Accounting. LG&E and KU are subject to the regulated operations guidance of the FASB ASC, under which regulatory assets are created based on expected recovery from customers in future rates to defer costs that would otherwise be charged to expense. Likewise, regulatory liabilities are created based on expected return to customers in future rates to defer credits that would otherwise be reflected as income, or, in the case of costs of removal, are created to match long-term future obligations arising from the current use of assets. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC, the Kentucky Commission, the Virginia Commission, or the Tennessee Regulatory Authority. See Note 5, Utility Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

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

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

Allowance for Doubtful Accounts. The allowance for doubtful accounts included in customer accounts receivable is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter. The allowance for doubtful accounts included in other accounts receivable is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

Materials and Supplies. Fuel, natural gas stored underground and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies. At December 31, 2009 and 2008, the emission allowances inventory totaled $1 million and less than $1 million, respectively.

Investment in Unconsolidated Venture. KU owns 20% of the common stock of EEI, which owns and operates a 1,162-Mw generating station in southern Illinois. EEI, through a power marketer affiliated with its majority owner, sells its output to third parties. KU's investment in EEI is accounted for under the equity method of accounting and, as of December 31, 2009 and 2008, totaled $21 million and $31 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment.

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

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

Depreciation and Amortization. Utility depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided for LG&E equaled 3.1% of average depreciable plant in 2009 and 2008. Of the amount provided for depreciation at LG&E at December 31, 2009, approximately 0.6% electric, 0.5% gas and 0.1% common were related to the retirement, removal and disposal costs of long lived assets. Of the amount provided for depreciation at LG&E at December 31, 2008, approximately 0.4% electric, 0.9% gas and 0.1% common were related to the retirement, removal and disposal costs of long lived assets. The amounts provided for KU equaled 2.6% of average depreciable plant in 2009 and 3.0% in 2008. Of the amounts provided for depreciation at KU at December 31, 2009, and 2008, approximately 0.4% and 0.5%, respectively, were related to the retirement, removal and disposal costs of long lived assets.

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

Income Taxes. In accordance with the income taxes guidance in the FASB ASC, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are many transactions for which the ultimate tax outcome is uncertain. The income taxes guidance of the FASB ASC prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Uncertain tax positions are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 10, Income Taxes.

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

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. KU and LG&E received an investment tax credit related to the construction of a new base load coal fired unit, TC2. See Note 10, Income Taxes.

Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of the Company's tax liability based on credits for certain construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Utility revenues are recorded based on service rendered to customers through month-end. LG&E and KU accrue estimates for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable for both LG&E and KU at December 31, 2009 and 2008, were approximately $140 million and $133 million, respectively.

Fuel and Gas Costs. The cost of fuel for electric generation is charged to expense as used, and the cost of natural gas supply is charged to expense as delivered to the distribution system. LG&E operates under a Kentucky Commission-approved performance-based ratemaking mechanism related to natural gas procurement activity. See Note 5, Utility Rates and Regulatory Matters, for a description of the FAC and GSC.

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

Reclassifications. Certain reclassification entries have been made to the previous years' financial statements to conform to the 2009 presentation. These reclassifications consist mainly of those necessary to present the Company's Argentine Gas Distribution businesses as discontinued operations. In addition, cash from operations was decreased by $15 million and cash flows from investing increased by $15 million. See Note 3, Discontinued Operations.

Recent Accounting Pronouncements.

Hierarchy of Generally Accepted Accounting Principles

The guidance related to the hierarchy of generally accepted accounting principles was issued in June 2009, and is effective for interim and annual periods ending after September 15, 2009. The guidance establishes the FASB ASC as the single source of authoritative nongovernmental U.S. generally accepted accounting principles. It had no effect on the Company's results of operations, financial position or liquidity; however, references to authoritative accounting literature have changed with the adoption.

Subsequent Events

The guidance related to subsequent events was issued in May 2009, and is effective for interim and annual periods ending after June 15, 2009. This guidance 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 this guidance had no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures were required with the adoption. See Note 17, Subsequent Events, for additional disclosures.

Employers' Disclosures about Postretirement Benefit Plan Assets

The guidance related to employers' disclosures about postretirement benefit plan assets was issued in December 2008, and is effective as of December 31, 2009. This guidance 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 had no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures were required with the adoption. See Note 7, Fair Value Measurements, and Note 9, Pension and Other Postretirement Benefit Plans, for additional disclosures.

Disclosures about Derivative Instruments and Hedging Activities

The guidance related to disclosures about derivative instruments and hedging activities was issued in March 2008, and is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this guidance is to enhance the current disclosure framework. The adoption had no impact on the Company's results of operations, financial position and liquidity; however, additional disclosures relating to derivatives were required with the adoption effective January 1, 2009. See Note 6, Financial Instruments, for additional disclosures.

Noncontrolling Interests in Consolidated Financial Statements

The guidance related to noncontrolling interests in consolidated financial statements was issued in December 2007, and is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this guidance is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company adopted this guidance effective January 1, 2009.

Fair Value Measurements

The guidance related to fair value measurements was issued in September 2006 and, 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. This guidance does not expand the application of fair value accounting to new circumstances.

In February 2008, guidance on fair value measurements and disclosures delayed the effective date 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 have been evaluated and have no impact on the Company's financial statements.

The Company adopted this guidance effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and it had no impact on the results of operations, financial position or liquidity, however, additional disclosures relating to its financial derivatives and cash collateral on derivatives, as required, are now provided. 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 results of operations, financial position or liquidity. In addition, no additional disclosures were required related to adopting this guidance.

The guidance related to 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 was issued in April 2009, and is effective for interim and annual periods ending after June 15, 2009. This update 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 had no impact on the Company's results of operations, financial position, or liquidity.

In August 2009, the FASB issued guidance related to fair-value measurement disclosures, which is effective for the first reporting period beginning after issuance. The guidance provides amendments to clarify and reduce ambiguity in valuation techniques, adjustments and measurement criteria for liabilities measured at fair value. The adoption had no impact on the Company's results of operations, financial position or liquidity.

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the first reporting period beginning after issuance except for disclosures about the roll-forward of activity in level 3 fair value measurements. This guidance will have no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures will be provided as required.

Note 2 - Goodwill Impairment

The following table shows goodwill as of and for the years ended December 31, 2009 and 2008. Goodwill is attributable to the Company's regulated utilities, LG&E and KU.

	Cost	Accumulated Impairment	Net
Balance at January 1, 2008	$ 4,136	$ -	$ 4,136
Impairment loss	-	(1,806)	(1,806)
Balance at December 31, 2008	4,136	(1,806)	2,330
Impairment loss	-	(1,493)	(1,493)
Balance at December 31, 2009	$ 4,136	$ 3,299	$ 837

The Company performs its required annual goodwill impairment test in the fourth quarter of each year. Impairment tests are performed between the annual tests when the Company determines that a triggering event that would more likely than not reduce the fair value of a reporting unit below its carrying value has occurred. The goodwill impairment test is comprised of a two-step process. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the regulated utilities (the goodwill reporting unit) to their carrying value, including goodwill, on the measurement date. If the fair value is less than the carrying value, then step 2 is performed to measure the amount of impairment loss. The step 2 calculation compares the implied fair value of the goodwill to the carrying value of the goodwill. The implied fair value of goodwill is equal to the excess of the regulated utilities' estimated fair value over the fair values of its identified assets and liabilities. If the carrying value of goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess (but not in excess of the carrying value).

The determination of the fair value of the regulated utilities and its assets and liabilities is performed as of the measurement date using observable market data before and after the measurement date (if that subsequent information is relevant to the fair value on the measurement date). For the 2009 annual impairment test, the estimated fair value of the regulated utilities was based on a combination of the income approach, which estimates the fair value of the reporting unit based on discounted future cash flows, and the market approach, which estimates the fair value of the reporting unit based on market comparables. The discounted cash flows for LG&E and KU were based on discrete financial forecasts developed by management for planning purposes and consistent with those given to E.ON AG. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for each of LG&E and KU and considered long-term earnings growth rates for publicly-traded peer companies. The level 3 income-approach valuations included a cash flow discount rate of 6.3% (6.3% in 2008) and a terminal-value growth rate of 1.1% (1.1% in 2008). In addition, subsequent to 2009 but prior to the issuance of the 2009 financial statements, discussions were held with interested parties for the possible sale of the Company, including the regulated utilities. Data from this process was used for evaluating the carrying value of goodwill as of December 31, 2009.

Based on information represented by bids received from interested parties, the Company completed a goodwill impairment analysis as of December 31, 2009. Step 1 of the impairment test indicated a possible impairment, so the Company completed step 2. The implied fair value of goodwill in the step 2 calculation was determined in the same manner utilized to estimate the amount of goodwill recognized in a business combination. The Company concluded that the fair values of LG&E and KU assets and liabilities equaled their book values, due to the regulatory environment in which they operate. The Kentucky and Virginia Commissions allow LG&E and KU to earn returns on the book values of their regulated asset bases at rates the Commissions determine to be fair and reasonable. Since there is no current prospect for deregulation, the Company assumed LG&E and KU will remain in a regulated environment for the foreseeable future. As a result of the impairment analysis described above, the Company recorded a 2009 goodwill impairment charge of $1.493 billion.

During 2008, the Company completed its annual goodwill impairment test during the fourth quarter, following the approach described above (except bid data from a possible sale transaction was not available and thus not utilized). Based on the 2008 assessment, the Company recorded a goodwill impairment charge of $1.806 billion.

The primary factors contributing to the goodwill impairment charges were the significant economic downturn, which caused a decline in the volume of projected sales of electricity to commercial customers, and an increase in the implied discount rate due to higher risk premiums. In addition, in 2009 a lower control premium was assumed, based on observable market data.

Note 3 - Discontinued Operations

WKE Lease

Through WKE and its subsidiaries, the Company had a 25-year lease on and operated the generating facilities of BREC, a power-generating cooperative in western Kentucky, and a coal-fired generating facility owned by the City of Henderson, Kentucky.

In March 2007, the Company entered into a termination agreement with BREC to terminate the lease and the operational agreements for nine coal-fired power plants and one oil-fired electricity-generating facility in western Kentucky. The transaction closed in July 2009. Assets and liabilities remaining after the completion of the transaction have been reclassified to continuing operations in the balance sheet at December 31, 2009. In 2009 the Company recorded a pretax loss of $114 million and made payments totaling approximately $627 million as part of the transaction. The Company will continue to make payments related to the transaction through the end of 2010 (and under certain circumstances to the end of 2011). The estimated cost of these payments were accrued at December 31, 2009. See also Note 7, Fair Value Measurements, Note 10, Income Taxes, and the Guarantees section in Note 13, Commitments and Contingencies, for further discussion of these or of additional elements of the WKEC lease termination transaction.

The tables below provide selected financial information for the WKE discontinued operations as of December 31, and for the years then ended (in millions of $):

	2009	2008
Revenues	$128	$300
Income (loss) before taxes	(222)	(309)
Income tax (expense) benefit	79	120
Net income (loss)	$(143)	$(189)
Assets:		
Current assets	$-	$153
Property, plant and equipment	-	202
Lease intangible	-	117
Deferred income taxes	-	317
Other	-	15
Total assets	$-	$804
Liabilities:		
Sales contract liability	$-	$908
Other	-	81
Total liabilities	$-	$989

Argentine Gas Distribution

At December 31, 2009 and 2008, the Company owned interests in two gas distribution companies in Argentina: 45.9% of Centro and 14.4% of Cuyana. These two entities serve a combined customer base of approximately one million customers. The Centro investment was consolidated due to the Company's majority ownership in the holding company of Centro. The Cuyana investment was accounted for using the equity method due to the ownership influence the Company exerts on the businesses.

In November 2009, subsidiaries of the Company entered into agreements to sell their direct and indirect interests in Centro and Cuyana, to E.ON Spain and a subsidiary, both affiliates of E.ON AG. On January 1, 2010, the parties completed the transfer of the interests for a sale price of $35 million. In December 2009, the Company recorded an impairment loss of $12.4 million before income taxes. The impairment loss represents the difference between the carrying values of the Company's interests in Centro and Cuyana and the sales price. The Company classified the assets, liabilities and results of operations of the Argentine gas distribution companies, including the impairment loss, as discontinued operations for all periods presented effective December 31, 2009. In connection with the reorganization transaction, E.ON Spain will also assume rights and obligations relating to claims and liabilities associated with the former Argentine businesses or indemnify the Company with respect to such matters.

The Company recognizes translation charges in other comprehensive income. These charges relate to the translation of the functional-currency financial statements of the Argentine investments into the Company's reporting currency. The translation at December 31, 2009, was performed using an exchange rate of 3.800 Argentine pesos to one U.S. dollar for assets and liabilities and an average exchange rate of 3.733 Argentine pesos to one U.S. dollar for income-statement amounts. The translation at December 31, 2008, was performed using an exchange rate of 3.454 Argentine pesos to one U.S. dollar for assets and liabilities and an average exchange rate of 3.158 Argentine pesos to one U.S. dollar for income-statement amounts. The pretax amounts recorded in accumulated OCI at December 31, 2009 and 2008, totaled $13 million and $17 million, respectively.

Argentine law requires that every Argentine company retain 5% of its Argentine GAAP net income until total legal reserves equal 20% of the value of the Argentine company's common stock and additional paid in capital. Legal reserves held in Argentina for the Argentine companies in which Capital Corp. had direct or indirect ownership interests equaled approximately $10 million and $11 million as of December 31, 2009 and 2008, respectively. These amounts satisfied the legal requirements at December 31, 2009 and 2008.

The tables below provide selected financial information for the Argentine gas distribution discontinued operations as of December 31, and for the years then ended (in millions of $):

	2009	2008
Revenues	$60	$69
Income before taxes	-	22
Income tax expense	(8)	(6)
Noncontrolling interest	(5)	(8)
Net (loss) income	$(13)	$8
Assets:		
Current assets	$25	$27
Property, plant and equipment	52	37
Investments in unconsolidated ventures	7	14
Deferred income taxes	6	38
Total assets	$90	$116
Liabilities:		
Other liabilities	$7	$17

Note 4 – Related Party Transactions

The Company had the following balances with E.ON AG and its affiliates as of December 31, (in millions of $):

	2009	2008
Accounts payable	$43	$57
Notes payable	851	299
Long-term debt	3,421	3,021
Dividends paid	49	68

The Company also recorded interest expense to E.ON and its affiliates of $155 million and $138 million in 2009 and 2008, respectively. See Note 10, Income Taxes, Note 11, Long-Term Debt, and Note 12, Notes Payable.

Note 5 - Utility Rates and Regulatory Matters

LG&E and KU are subject to the jurisdiction of the Kentucky Commission and the FERC, and KU is further subject to the jurisdiction of the Virginia Commission and the Tennessee Regulatory Authority, in virtually all matters related to electric and gas utility regulation, and as such, their accounting is subject to the regulated-operations guidance of the FASB ASC. Given their position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

2010 Kentucky Electric and Gas Rate Cases. In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its gas base rates of approximately 8%, or $23 million annually, including an 11.5% return on equity for electric and gas. At the same time, KU also filed an application with the Kentucky Commission requesting an increase in base electric rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. LG&E and KU have requested the increases based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund if the Kentucky Commission has not issued an order in the proceeding. The parties are currently exchanging data requests in the proceedings and a hearing date has been scheduled for June 2010. An order in the proceedings may occur during the third or fourth quarters of 2010.

2008 Electric and Gas Rate Cases. In July 2008, LG&E filed an application with the Kentucky Commission requesting increases in base electric and gas rates. At the same time, KU also filed an application with the Kentucky Commission requesting an increase in base electric rates. In January 2009, LG&E, the AG, the KIUC and all other parties to the rate cases filed a settlement agreement with the Kentucky Commission, under which LG&E's base gas rates increased by $22 million annually, and base electric rates decreased by $13 million annually. At the same time, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's base electric rates decreased by $9 million annually. Orders approving the settlement agreements were received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated.

In conjunction with the filing of the application for changes in base rates, the VDT surcredit terminated. The VDT surcredit resulted from a 2001 initiative to share savings of $25 million and $10 million for LG&E and KU, respectively, from the VDT initiative with customers over five years. In February 2006, LG&E, KU and all parties to the proceeding reached a unanimous settlement agreement on the future ratemaking treatment of the VDT surcredit, which was approved by the Kentucky Commission in March 2006, at an annual rate of $9 million and $4 million for LG&E and KU, respectively. Under the terms of the settlement agreement, the VDT surcredit continued at its current level until such time as LG&E filed for a change in electric or natural gas base rates or KU filed for a change in electric base rates. In accordance with the Order, the VDT surcredit terminated in August 2008, the first billing month after the July 2008 filing for a change in base rates.

In December 2007, LG&E and KU submitted their plans to allow the merger surcredit to terminate as scheduled on June 30, 2008. The merger surcredit originated as part of the LG&E Energy merger with KU Energy Corporation in 1998. In June 2008, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case which provided for a reduction in the merger surcredit to approximately $12 million ($6 million each for LG&E and KU) for a 7-month period beginning July 2008, termination of the merger surcredit when new base rates went into effect on or after January 31, 2009, and that the merger surcredit be continued at an annual rate of $24 million ($12 million each for LG&E and KU) thereafter should LG&E and KU not file for a change in base rates. In accordance with the Order, the merger surcredit was terminated effective February 6, 2009, with the implementation of new base rates.

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 reflected a proposed rate of return on rate base of 8.586% based upon a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission order, KU elected to implement the proposed rates effective November 1, 2009 on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU will refund certain amounts collected since November 2009, consisting of interim increased rates in excess of the ultimate approved rates. These refunds aggregate approximately $1 million and are anticipated to occur during the second quarter of 2010. See Note 17, Subsequent Events.

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 and were approved by the FERC during September 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 may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An order by the FERC on this matter may occur during 2010. KU is not currently able to predict the outcome of this proceeding, including whether its wholesale customers may or may not be entitled to certain rights or benefits relating to renewable energy, and the financial or operational effects, if any, of such outcomes.

Regulatory Assets and Liabilities. The following regulatory assets and liabilities were included in the consolidated balance sheets as of December 31, (in millions of $):

	2009	2008
Current regulatory assets:		
GSC	$3	$28
ECR	35	24
FAC	1	15
Net MISO exit	3	-
Other	4	8
Total current regulatory assets	$46	$75
Non-current regulatory assets:		
Storm restoration	$126	$26
ARO	60	57
Unamortized loss on bonds	34	36
Net MISO exit	13	31
Other	9	3
Subtotals	242	153
Pension and postretirement benefits	309	387
Total non-current regulatory assets	$551	$540
Current regulatory liabilities:		
GSC	$34	$30
DSM	7	10
Total current regulatory liabilities	$41	$40
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$587	$580
Deferred income taxes – net	50	61
Postretirement benefits	9	10
Other	17	26
Total non-current regulatory liabilities	$663	$677

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. 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. LG&E and KU will recover these assets through pension expense included in the calculation of base rates with the Kentucky Commission and KU 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. 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. LG&E and KU are seeking recovery of the Storm restoration regulatory asset and adjustments to the amortization of the CMRG and KCCS contributions, included in other regulatory assets, in their current base rate cases. LG&E and KU recover through the calculation of base rates, the amortization of the net MISO exit regulatory asset in Kentucky incurred through April 30, 2008. KU recently received approval to recover the Virginia portion of this asset, as incurred through December 31, 2008, over a five-year period 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. LG&E also recovers through the calculation of base rates other regulatory assets including the costs of an EKPC FERC transmission settlement agreement and rate case expenses. KU recovers through the calculation of base rates, the amortization of the remaining regulatory assets, including other regulatory assets comprised of deferred storm costs, the costs of an 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 current base rate case.

ARO. A summary of LG&E's and KU's net ARO assets, regulatory assets, ARO liabilities, regulatory liabilities and cost of removal established under the asset retirement and environmental obligations guidance of the FASB ASC, follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets	Regulatory Liabilities
As of December 31, 2007	$9	$(60)	$48	$(2)
ARO accretion	-	(3)	4	-
ARO depreciation	-	-	5	(5)
As of December 31, 2008	9	(63)	57	(7)
ARO accretion	-	(5)	4	-
ARO depreciation	-	-	1	-
ARO settlements	-	1	(2)	-
Removal cost incurred	-	1	-	-
As of December 31, 2009	$9	$(66)	$60	$(7)

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $4 million ($2 million each for LG&E and KU) in 2009 and 2008 for the ARO accretion and depreciation expense.

LG&E's and KU's AROs are primarily related to the final retirement of assets associated with generating units. LG&E's also include natural gas wells. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory liability pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC. For the year ended December 31, 2008, removal costs incurred were less than $1 million. For the years ended December 31, 2009 and 2008, LG&E and KU each recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC.

LG&E's and KU's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

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

GSC. LG&E's natural gas rates contain a GSC, whereby increases or decreases in the cost of natural gas supply are reflected in LG&E's rates, subject to approval by the Kentucky Commission. The GSC procedure prescribed by Order of the Kentucky Commission provides for quarterly rate adjustments to reflect the expected cost of natural gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of natural gas supply cost from prior quarters is to be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters.

LG&E's GSC was modified in 1997 to incorporate a natural gas procurement incentive mechanism. Since November 1, 1997, LG&E has operated under this Performance Based Ratemaking ("PBR") mechanism related to its natural gas procurement activities. LG&E's rates are adjusted annually to recover (or refund) its portion of the expense (or savings) incurred during each PBR year (12 months ending October 31). During the PBR years ending in 2009 and 2008, LG&E achieved $7 million and $11 million in savings, respectively. In 2009 and 2008, of the total savings amount, LG&E's portion was approximately $2 million and $3 million, respectively, and the customers' portion was approximately $5 million and $8 million, respectively. Pursuant to the extension of LG&E's natural gas supply cost PBR mechanism effective November 1, 2001, the sharing mechanism under the PBR requires savings (and expenses) to be shared 25% with shareholders and 75% with customers up to 4.5% of the benchmarked natural gas costs. Savings (and expenses) in excess of 4.5% of the benchmarked natural gas costs are shared 50% with shareholders and 50% with customers. The current natural gas supply cost PBR mechanism was extended through 2010 without further modification. In December 2009, LG&E filed with the Kentucky Commission for an extension of LG&E's natural gas supply cost PBR mechanism through 2015 with certain modifications.

MISO. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, related to proceedings that had been underway since July 2003, LG&E and KU withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, LG&E and KU have been operating under a FERC-approved open access-transmission tariff. LG&E and KU now contract with the Tennessee Valley Authority to act as their transmission Reliability Coordinator and Southwest Power Pool, Inc. to function as their Independent Transmission Organization, pursuant to FERC requirements.

LG&E and KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the utilities following their withdrawal. In October 2006, LG&E and KU paid $13 million and $20 million, respectively, to the MISO and made related FERC compliance filings. The utilities' payments of these exit fees were with reservation of their rights to contest the amount, or components thereof, following a continuing review of the fee's calculation and supporting documentation. LG&E and KU and the MISO resolved their dispute regarding the calculations of the exit fees and, in November 2007, filed applications with the FERC for approval of recalculation agreements. In March 2008, the FERC approved the parties' recalculations of the exit fees, and the approved agreements provided LG&E and KU with an immediate recovery of less than $1 million each and an estimated $2 million and $3 million, respectively, over the next seven years for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, LG&E and KU have established regulatory assets 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. This regulatory liability balance as of October 31, 2009, has been included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they 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, LG&E and KU established reserves during the fourth quarter of 2008 of $2 million and less than $1 million, respectively, 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 receivables were established for amounts already paid of $1 million and less than $1 million for LG&E and KU, respectively, which the MISO began refunding back to LG&E and KU 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. Accruals had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accruals had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accruals for the former time period were reversed and accruals for the latter time period were recorded in June 2009, with a net effect of less than $1 million and $1 million of expense for LG&E and KU, respectively, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC orders and a related task-force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009. The conclusion of the RSG matter, including the retroactivity decision, may result in refunds to the utilities, but the utilities cannot predict the ultimate outcome of this matter, nor the financial impact, at this time.

In November 2009, LG&E and KU filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with Southwest Power Pool, Inc. in September 2010. The application seeks authority for LG&E and KU to function after such date as the administrators of their own open access transmission tariffs for most purposes. The Tennessee Valley Authority, which currently acts as Reliability Coordinator, would also assume certain additional duties. A number of parties have intervened and filed comments in the matter and initial stages of data response proceedings have occurred. The application is subject to continuing FERC proceedings, including further submissions or filings by, intervenors or FERC staff, prior to a ruling by the FERC. During January 2010, the Kentucky Commission issued an Order generally authorizing relevant state regulatory aspects of the proposed arrangements.

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

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

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. In November 2009, January 2009 and May/June 2008, the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2009, April 2008, and October 2007, respectively. In January 2009, the Kentucky Commission initiated a routine examination of the 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 periods.

KU also employs a 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 December 31, 2009 and 2008, KU had a regulatory liability of less than $1 million and a regulatory asset of $2 million, respectively.

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. KU indicated the Virginia Staff proposal was 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.

In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kwh from the factor in effect for the April 2007 through March 2008 period.

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

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April 2008 and October 2007, and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

In January 2010, the Kentucky Commission initiated a six-month review of LG&E's and KU's environmental surcharges for the billing period ending October 2009. The proceeding will progress throughout the first half of 2010.

In June 2009, LG&E and KU 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 their generating facilities. During 2009, LG&E and KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving LG&E's and KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle.

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

Storm Restoration. In January 2009, a significant ice storm passed through LG&E's and KU's service territories causing approximately 205,000 and 199,000 customer outages, respectively, followed closely by a severe wind storm in February 2009, causing approximately 37,000 and 44,000 customer outages, respectively. LG&E and KU 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 and $62 million, respectively, in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing LG&E and KU to establish regulatory assets of up to $45 million and $62 million, respectively, based on their actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, LG&E and KU established regulatory assets of $44 million and $57 million, respectively, for actual costs incurred, and LG&E and KU are seeking recovery of these assets in their current base rate cases.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service territories causing significant outages and system damage. In October 2008, LG&E and KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, for approximately $24 million and $3 million, respectively, of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing LG&E and KU to establish regulatory assets of up to $24 million and $3 million, respectively, based on their actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, LG&E and KU established regulatory assets of $24 million and $2 million, respectively, for actual costs incurred, and LG&E and KU are seeking recovery of these assets in their current base rate cases.

Mill Creek Ash Pond Costs. In June 2005, the Kentucky Commission issued an Order approving LG&E's establishment of a regulatory asset for $6 million in costs related to the removal of ash from the Mill Creek ash pond, and authorized amortization over four years beginning in May 2006.

FERC Jurisdictional Pension Costs. Other regulatory assets include pension costs of $3 million incurred by KU and allocated to its FERC jurisdictional ratepayers. KU will seek recovery of this asset in the next FERC rate proceeding.

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

CMRG and KCCS Contributions. In July 2008, LG&E and KU, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. LG&E and KU jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and LG&E and KU are seeking rate recovery in their 2010 base rate cases.

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

Pension and Postretirement Benefits. LG&E and KU account for pension and postretirement benefits in accordance with the compensation – retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, LG&E and KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on the compensation – retirement benefits guidance of the FASB ASC. Regulators have been clear and consistent with their historical treatment of such rate recovery, therefore, the Companies have recorded a regulatory asset or liability representing the change in funded status of the pension and postretirement plans that is expected to be recovered. The regulatory asset or liability will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Accumulated Cost of Removal of Utility Plant. As of December 31, 2009 and 2008, LG&E has segregated the cost of removal, previously embedded in accumulated depreciation, of $256 million and $251 million, respectively, in accordance with FERC Order No. 631. As of December 31, 2009 and 2008, KU has segregated the cost of removal, previously embedded in accumulated depreciation, of $331 and $329 million, respectively, in accordance with the same Order. This cost of removal component is for assets that do not have a legal ARO under the asset retirement and environmental obligations guidance of the FASB ASC. For reporting purposes in the balance sheets, LG&E and KU have presented this cost of removal as a regulatory liability pursuant to the regulated operations guidance of the FASB ASC.

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

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

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

Other Regulatory Matters

Kentucky Commission Report on Storms. In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or response measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, LG&E and KU filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas, and fielding of enhanced operational and customer outage-related systems.

Wind Power Agreements. In August 2009, LG&E and KU filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009, and are contingent upon LG&E and KU receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, LG&E and KU would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Companies filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Companies' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order currently provides for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, LG&E and KU filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. On March 24, 2010, LG&E and KU delivered notices of termination under provisions of the wind power contracts permitting termination if certain conditions precedent were not accomplished by a fixed date. The Companies also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding.

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 the Companies, together with the IMEA and the IMPA. In July 2009, the utilities notified the Kentucky Commission of the proposed sale 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 sold are intended to provide KU an ownership interest in these common assets that is proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, LG&E and KU completed the sale transaction at a price of $48 million, representing the current net book value of the assets, multiplied by the proportional interest being sold.

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. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized LG&E and KU on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, final authorization approving the proposed rates was received.

TC2 CCN Application and Transmission Matters. An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued 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 property owners in Hardin County, Kentucky.

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. A motion for discretionary review of that reversal was filed by LG&E and KU with the Kentucky Supreme Court and was granted in April 2009. That proceeding, which seeks reinstatement of the Circuit Court dismissal of the CCN challenge, has been fully briefed and oral argument occurred during March 2010. A ruling on the matter could occur by mid 2010.

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, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In April 2009, that appellate court denied KU's motion to lift the stay and issued an Order retaining the stay until a decision on the merits of the appeal. Efforts to seek reconsideration of that ruling, or to obtain intermediate review of the ruling by the Kentucky Supreme Court, were unsuccessful, and the stay remains in effect. The underlying appeal on KU's right to condemn remains pending before the Court of Appeals and oral argument on the matter is scheduled to occur during late March 2010.

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.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU has obtained easements to allow construction of temporary transmission facilities bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status. In parallel with, and consistent with the relevant proceedings and their status, KU is conducting appropriate real estate acquisition and construction activities with respect to these temporary transmission facilities.

In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky. In that action, the landowners claim that the U.S. Army failed to comply with certain National Historic Preservation Act requirements 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 and in October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals.

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.

Arena. In August 2006, LG&E filed an application with the Kentucky Commission requesting approval for the sale of property to the Louisville Arena Authority which was granted in a September 2006 Order. In November

2006, LG&E completed certain agreements pursuant to its August 2006 Memorandum of Understanding with the Louisville Arena Authority regarding the proposed construction of an arena in downtown Louisville. LG&E entered into a relocation agreement with the Louisville Arena Authority providing for the reimbursement to LG&E of the costs to be incurred in relocating certain LG&E facilities related to the arena transaction of approximately $63 million. As of December 31, 2009, approximately $62 million of the total costs have been received. The relocation work was substantially completed during 2009, with follow up work continuing in 2010 and 2011. The parties further entered into a property sale contract providing for LG&E's sale of a downtown site to the Louisville Arena Authority which was completed for $9 million in September 2008.

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.

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

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at control area interfaces or into control areas involving market power. In July 2009, the FERC issued an order approving LG&E's and KU's September 2008 application for market-based rate authority. During July 2009, affiliates of LG&E and KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Corporation control area, which termination should ultimately allow a filing to request a determination that LG&E and KU no longer are deemed to have market power in such control area.

LG&E and KU conduct certain of their wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. LG&E's and

KU's sales under market-based rate authority totaled $27 million and less than $1 million, respectively, for the year ended December 31, 2009.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("NERC"), which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. LG&E and KU are members of the SERC Reliability Corporation ("SERC"), which acts as LG&E's and KU's RRO. During May 2008, the SERC and LG&E and KU agreed to a settlement involving penalties totaling less than $1 million for each utility related to LG&E's and KU's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. During December 2009, the SERC and LG&E and KU agreed to a settlement involving penalties totaling less than $1 million for each utility concerning a June 2008 self-report by LG&E and KU relating to three other standards and an October 2008 self-report relating to an additional standard. During December 2009, LG&E and KU submitted a self-report relating to an additional standard, the resolution of which the Companies do not anticipate will result in material penalties or remedial actions. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. While LG&E and KU believe they are in compliance with the mandatory reliability standards, they cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Integrated Resource Planning. Integrated resource planning ("IRP") regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, LG&E and KU filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. Pursuant to the Virginia Commission's December 2008 Order, KU filed its 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.

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

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252 and Section 1254 standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E and KU developed real-time pricing pilots for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilots program proposed by LG&E and KU for implementation within approximately eight months, for their large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008. LG&E and KU file annual reports on the program within 90 days of each plan year-end for the 3-year pilot period.

Pursuant to a LG&E 2004 rate case settlement agreement, and as referred to in the Kentucky Commission EPAct 2005 Administrative Order, LG&E made its responsive pricing and smart metering pilot program filing, which addresses real-time pricing for residential and general service customers, in March 2007. In July 2007, the Kentucky Commission approved the application as filed, for 100 residential customers and a sampling of other customers, and authorized LG&E to establish the responsive pricing and smart metering pilot program, recovery of non-specific customer costs through the DSM billing mechanism and the filing of annual reports by April 1, 2009, 2010 and 2011. LG&E must also file an evaluation of the program by July 1, 2011.

Hydro Upgrade. In October 2005, LG&E received from the FERC a new license to upgrade, operate and maintain the Ohio Falls Hydroelectric Project. The license is for a period of 40 years, effective November 2005. LG&E began refurbishing the facility to add approximately 20 Mw of generating capacity in 2004, and plans to spend approximately $55 million from 2010 to 2012.

Green Energy Riders. In February 2007, LG&E and KU filed a Joint Application and Testimony for Proposed Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing LG&E and KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits. During November 2009, LG&E and KU filed an application to both continue and modify the existing Green Energy Programs and requested a Kentucky Commission Order by March 2010.

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

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

Depreciation Study. In December 2007, LG&E and 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.

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

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. LG&E and KU do not expect any financial or other impact as a result of this Order. In April 2009, LG&E and 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, which suspended for five months all net metering tariffs filed by the jurisdictional electric utilities. This suspension was 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 an informal conference with the parties to discuss issues related to the net metering tariffs filed by LG&E and KU. Following this conference, the intervenors and LG&E and KU resolved all issues and LG&E and KU 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 established a procedural schedule that allowed for data discovery and testimony through July 2009. A public hearing has not been scheduled in this matter. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments.

Note 6 - Financial Instruments

The cost and estimated fair values of the Company's non-trading financial instruments as of December 31, 2009 and 2008 follow (in millions of $):

	2009		2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion):				
Affiliated companies	3,421	3,553	3,021	2,925
External	765	764	765	744
Interest rate swaps (liability)	28	28	55	55

The fair values for external long-term debt reflect prices quoted by dealers. The fair values for debt due to affiliates are 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 the Company'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 guidance of the FASB ASC. 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.

The Company is subject to the risk of fluctuating interest rates in the normal course of business. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2009, a 100-basis-point change in the benchmark rate on the Company's variable-rate debt, not hedged by an interest rate swap, would impact pre-tax interest expense by $23 million annually.

Interest Rate Swaps. LG&E uses over-the-counter interest rate swaps to limit exposure to market fluctuations in certain of its debt instruments. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature.

The fair value of the interest rate swaps is determined by a quote from the counterparty. This value is verified monthly by LG&E using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. Market liquidity is considered, however the valuation does not require an adjustment for market liquidity as the market is very active for swaps such as LG&E utilizes. LG&E considered the impact of counterparty credit risk by evaluating credit ratings and financial information. All counterparties had strong investment grade ratings at December 31, 2009. LG&E did not have any credit exposure to the swap counterparties, as it was in a liability position at December 31, 2009, therefore, the market valuation required no adjustment for counterparty credit risk. In addition, LG&E and certain counterparties have agreed to post margin if the credit exposure exceeds certain thresholds. Cash collateral for interest rate swaps is included in long-term assets in the accompanying balance sheets.

LG&E was party to various interest rate swap agreements with aggregate notional amounts of $179 million as of December 31, 2009 and 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 0.20% and 1.27% at December 31, 2009 and 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. One swap with a notional value of $32 million was terminated by the counterparty in December 2008. See Note 11, Long-Term Debt. The remaining interest rate swaps designated to hedge the same bond became ineffective during 2008 as a result of the impact of downgrades of the bond insurers of the underlying debt.

The interest rate swaps are accounted for on a mark-to-market basis in accordance with the derivatives and hedging guidance of the FASB ASC. Financial instruments designated as effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and member's equity. See Note 15, Accumulated Other Comprehensive Income. The ineffective portion of financial instruments designated as cash flow hedges is recorded to earnings monthly as is the entire change in the market value of the ineffective swaps.

The table below shows the pretax amount and income statement location of other gains and losses from interest-rate swaps for the years ended December 31, 2009 and 2008 (in millions of $):

	Notes	Amount 2009	2008
Change in market value of ineffective swaps	(1)	$21	$(36)
Change in the ineffective portion of swaps deemed highly effective	(2)	1	(8)
Totals		$22	$(44)

Notes:

(1) Included in mark-to-market income (expense).

(2) Included in interest expense.

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 years ended December 31, 2009 and 2008, 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, used as collateral for one of the interest rate swaps, is included in long-term assets in the accompanying balance sheets. The deposit equaled $17 million and $22 million at December 31, 2009 and 2008, respectively. 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 $28 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. The Company 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 guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from the Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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. 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.

The Company 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, the Company seeks to enter into netting agreements or require cash deposits, letter of credit and parental company guarantees as security from counterparties. The Company 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, the Company 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 December 31, 2009, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company 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's or Moody's. At December 31, 2009 and 2008, credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at December 31, 2009 and 2008, was 631,200 Mwhs and 292,000 Mwhs, respectively. All the volume outstanding at December 31, 2009, will settle in 2010.

The Company manages the price volatility of its forecasted electric wholesale sales by selling market-traded electric forward contracts and swaps. Hedge accounting treatment has not been elected for these transactions, and therefore realized and unrealized gains and losses are included in the statements of income in electric utility revenues. The Company recorded realized gains of $11 million and unrealized losses of $2 million during the twelve months ended December 31, 2009, and realized and unrealized gains of $4 million and $2 million, respectively, during the twelve months ended December 31, 2008.

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. At December 31, 2009, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position, and no collateral posted in the normal course of business. If the credit risk related contingent features underlying these agreements were triggered on December 31, 2009, due to a one notch downgrade in the Company's credit rating, there would be no effect on the energy trading and risk management contracts or collateral required as a result of these contracts.

See Note 3, Discontinued Operations, for a discussion of the WKE sales contract derivative.

Note 7 - Fair Value Measurements

The Company adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 - Include other inputs that are directly or indirectly observable in the marketplace.

- Level 3 - Unobservable inputs which are supported by little or no market activity.

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The Company measures the assets and liabilities listed in the table below at fair value. The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in liquid accounts. The Company classifies its liability for the E.ON share performance plan within level 2 because it is valued using a model that considers the quoted market price of E.ON's common shares traded on the Frankfurt Stock Exchange as well as other relevant economic measure. See Note 16, Share Performance Plan. The Company classifies its derivative contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

Prior to its termination in 2009, the Company classified its liability for WKE's long-term sales contract within level 3. The contracts were with an electric cooperative and two aluminum smelters. The valuation was done on a monthly basis using market prices from Platts' on-line pricing service for the current and forward four years and a forecast for the outer years where market prices are not available. The outer year pricing was extrapolated from an annual forecast from the Energy Information Administration for NGHH pricing based on historical ratios of around-the-clock electricity prices to NGHH prices. See Note 3, Discontinued Operations.

The Company has an obligation through the end of 2010 (and under certain circumstances to the end of 2011) to pay one of the aluminum smelters the difference between the electricity prices charged by WKE under the old long-term sales contract and the electricity prices charged by its current electricity supplier. The Company also classifies this liability within level 3. The valuation is calculated on a quarterly basis using monthly Northern East Central Area Reliability ("NECAR")/Cinergy Hub forward prices by peak-type. See Note 3, Discontinued Operations.

Assets and liabilities measured at fair value as of December 31, 2009, are summarized below (in millions of $):

	Quoted Prices In Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Totals
Assets:				
Interest-rate swap cash collateral	$17	$-	$-	$17
Electricity derivative cash collateral	2	-	-	2
Electricity derivative contracts	-	2	-	2
Total assets	$19	$2	$-	$21
Liabilities:				
Interest-rate swaps	$-	$28	$-	$28
Electricity derivative contracts	-	2	-	2
Smelter contract - discontinued operations	-	-	75	75
E.ON share performance plan	-	2	-	2
Total liabilities	$-	$32	$75	$107

At December 31, 2009, interest-rate swap cash collateral was included in accounts receivable and other long-term assets in the accompanying balance sheet, and the electricity derivative contract asset was included in prepayments and other current assets. Interest-rate swaps were included in other current liabilities and derivative liability (noncurrent) in the accompanying balance sheet, and the electricity derivative contract liability was included in derivative liability (current). The smelter-contract liability was included in derivative liability (noncurrent), and the liability for the E.ON share performance plan was included in other long-term liabilities.

Assets and liabilities measured at fair value as of December 31, 2008, are summarized below (in millions of $):

	Quoted Prices In Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Totals
Assets:				
Interest-rate swap cash collateral	$22	$-	$-	$22
Electricity derivative cash collateral	1	-	-	1
Electricity derivative contracts	-	3	-	3
Total assets	$23	$3	$-	$26
Liabilities:				
Interest-rate swaps	$-	$56	$-	$56
Long-term sales contract - discontinued operations	-	-	908	908
E.ON share performance plan	-	2	-	2
Total liabilities	$-	$58	$908	$966

At December 31, 2008, interest-rate swap cash collateral and electricity derivative cash collateral were included in restricted cash (noncurrent) in the accompanying balance sheet, and the electricity derivative contract asset was included in prepayments and other current assets. Interest-rate swaps were included in other current liabilities and derivative liability (noncurrent) in the accompanying balance sheet. The long-term sales contract liability was included in liabilities of discontinued operations, and the liability for the E.ON share performance plan was included in other long-term liabilities.

The following table presents the changes in net liabilities measured at fair value using significant unobservable inputs (level 3) as defined in FASB ASC for the twelve months ended December 31 (in millions of $):

	2009	2008
Balance at beginning of year	$908	$832
Realized losses included in earnings	5	-
Unrealized losses included in earnings	108	581
Unrealized gains included in earnings	(1,026)	(505)
Issuances	106	-
Settlements	(26)	-
Balance at end of year	$75	$908

Note 8 - Concentrations of Credit and Other Risks

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

LG&E's customer receivables and gas and electric revenues arise from deliveries of natural gas to approximately 321,000 customers and electricity to approximately 396,000 customers in Louisville and adjacent areas in Kentucky. KU's customer receivables and revenues arise from deliveries of electricity to approximately 515,000 customers in over 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and five customers in Tennessee. For the year ended December 31, 2009, 72% of LG&E's revenues were derived from electric operations and 28% from gas operations, and for the year ended December 31, 2008, 69% of LG&E's revenues were derived from electric operations and 31% from gas operations. All of KU's revenues were derived from electric operations in both years. During 2009, LG&E's 10 largest electric and gas customers accounted for less than 15% and less than 10% of total volumes, respectively. During 2009, KU's 10 largest customers accounted for less than 15% of electric volumes.

Effective November 2008, LG&E and employees represented by the IBEW Local 2100 signed a three-year collective bargaining agreement. This agreement provides for negotiated increases or changes to wages, benefits or other provisions. The employees represented by this bargaining agreement comprise approximately 67% of LG&E's workforce at December 31, 2009.

Effective August 4, 2009, KU and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. KU and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 15% of KU's workforce at December 31, 2009.

Note 9 - Pension and Other Postretirement Benefit Plans

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

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the defined benefit plans' obligations and fair value of assets over the two-year period ending December 31, 2009, and the funded status for the plans as of December 31, (in millions of $):

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
Change in benefit obligation				
Benefit obligation at beginning of year	$1,013	$924	$185	$184
WKE's obligation previously in discontinued operations	33	-	7	-
Service cost	22	19	4	4
Interest cost	63	60	11	11
Plan amendments	-	-	1	3
Curtailment (gain) or loss	1	-	(3)	-
Settlement loss	2	-	-	-

	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
Benefits paid, net of retiree contributions	(62)	(49)	(12)	(13)
Actuarial (gain) or loss	13	59	6	(4)
Benefit obligation at end of year	$1,085	$1,013	$199	$185
Change in plan assets				
Fair value of plan assets at beginning of year	$577	$814	$24	$26
WKE's fair value of plan assets previously in discontinued operations	21	-	1	-
Actual return (loss) on plan assets	126	(190)	5	(5)
Employer contributions	35	4	19	16
Benefits paid, net of retiree contributions	(62)	(49)	(12)	(13)
Administrative expenses	(1)	(2)	-	-
Fair value of plan assets at end of year	$696	$577	$37	$24
Funded status at end of year	$(389)	$(436)	$(162)	$(161)

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

	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
Accrued benefit liability – current	$(7)	$(2)	$(4)	$(3)
Accrued benefit liability – non-current	(382)	(434)	(158)	(157)
Amounts recognized in regulatory assets and liabilities:				
Transition obligation	$-	$-	$5	$7
Prior service cost	37	43	8	10
Accumulated loss (gain)	256	327	(6)	(10)
Total regulatory assets and liabilities	$293	$370	$7	$7
Amounts recognized in accumulated OCI:				
Prior service (cost) credits	$(21)	$(25)	$1	$(2)
Accumulated loss	(59)	(82)	(1)	-
Total accumulated OCI (Note 15)	$(80)	$(107)	$-	$(2)
Additional year-end information for plans with benefit obligations in excess of plan assets:				
Benefit obligation	$1,085	$1,013	$199	$185
Accumulated benefit obligation	919	852	-	-
Fair value of plan assets	696	577	37	24

The amounts recognized in regulatory assets and liabilities for the years ended December 31 are composed of the following (in millions of $):

	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
Prior service cost arising during period	$-	$-	$-	$3
Net (gain) loss arising during period	(49)	248	3	1
Amortization of prior service cost	(7)	(7)	(2)	(2)
Amortization of transitional obligation	-	-	(2)	(2)
Amortization of (loss) gain	(21)	(2)	1	-
Total amounts recognized in regulatory assets and liabilities	$(77)	$239	$-	$-

The amounts recognized in accumulated OCI for the years ended December 31 are composed of the following (in millions of $):

	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
Prior service cost arising during period	$-	$-	$-	$1
Prior service cost recognized due to curtailment	(2)	-	(1)	-
Settlement recognition of net loss	(2)	-	-	-
Net (gain) loss arising during period	(17)	76	(1)	3
Amortization of prior service cost	(2)	(3)	-	-
Amortization of loss	(4)	-	-	-
Total amounts recognized in accumulated OCI	$(27)	$73	$(2)	$4

For a discussion of the pension and postretirement regulatory assets and liabilities, see Note 5, Utility Rates and Regulatory Matters.

Components of Net Periodic Benefit Costs. The following table provides the components of net periodic benefit cost for the plans for the twelve months ended December 31, (in millions of $):

	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
Service cost	$20	$19	$4	$4
Interest cost	62	60	11	11
Expected return on plan assets	(47)	(65)	(2)	(2)
Amortization of prior service cost	9	9	3	2
Amortization of transition obligation	-	-	2	-
Amortization of actuarial loss (gain)	27	3	(1)	2
Net periodic benefit cost	$71	$26	$17	$17

The estimated amounts that will be amortized from regulatory assets and liabilities and accumulated OCI into net periodic benefit cost in 2010 follow (in millions of $):

	Pension Benefits	Other Postretirement Benefits
Regulatory assets and liabilities:		
Net actuarial loss	$16	$-
Prior service cost	6	2
Transition obligation	-	2
Total regulatory assets and liabilities amortized during 2010	$22	$4
Accumulated OCI:		
Net actuarial loss	$5	$-
Prior service cost	3	-
Total accumulated OCI amortized during 2010	$8	$-

The weighted-average assumptions used in the measurement of the Company's pension benefit obligations as of December 31 are shown in the following table:

	2009	2008
Discount rate - LG&E union plan	6.08%	6.33%
Discount rate - WKE union plan	5.00%	6.43%
Discount rate - nonunion plan	6.13%	6.25%
Discount rate - SERP plan	5.79%	6.38%
Discount rate - officer SERP plan	6.14%	6.36%
Discount rate - restoration plan	6.31%	6.29%
Rate of compensation increase	5.25%	5.25%

The discount rates were determined by the December 28, 2009, Mercer Pension Discount Yield Curve. These discount rates were then lowered by 8 basis points for the average change in 4 bond indices, Citigroup High Grade Credit Index AAA/AA 10+ years, Barclays Capital U.S. Long Credit AA, Merrill Lynch U.S. Corporate AA-AAA rated 10+ years and Merrill Lynch U.S. Corporate AA rated 15+ years, for the period from December 28, 2009, to December 31, 2009.

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

	2009	2008
Discount rate	6.25%	6.66%
Expected long-term rate of return on plan assets	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, the Company considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption per the portfolio. The Company has determined that the 2010 expected long-term rate of return on assets assumption should be 7.75%.

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

- A 1% change in the assumed discount rate could have an approximate $121 million positive or negative impact on the 2009 accumulated benefit obligation and an approximate $158 million positive or negative impact on the 2009 projected benefit obligation.

- A 25-basis point change in the expected rate of return on assets would have an approximate $2 million positive or negative impact on 2009 pension expense.

Assumed Health Care Cost Trend Rates. For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for 2009. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million on the 2009 total of service and interest costs components and an increase or decrease of less than $7 million in year-end 2009 postretirement benefit obligations.

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

	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2010	$54	$14	$(1)
2011	49	15	-
2012	50	15	(1)
2013	51	16	-
2014	53	16	(1)
2015 - 2019	322	86	(3)

Plan Assets. The following table shows the pension plans' weighted-average asset allocations by asset category at December 31:

	Target Range	2009	2008
Equity securities	45% - 75%	59%	55%
Debt securities	30% - 50%	40%	43%
Other	0% - 10%	1%	2%
Totals		100%	100%

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

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

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

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

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

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government. The 401(h) plan provides for postretirement benefits for covered individuals and is invested within the pension trust.

The Company classifies plan assets 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 guidance of the FASB ASC. See Note 7, Fair Value Measurements. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

> *Money Market Fund:* These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.
>
> *Common/Collective Trusts:* Valued based on the beginning-of-year value of the plans' interests in the trusts plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trusts, with the exception of the GAC. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce fair values that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other plan market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. There were no changes in the plans' valuation methodologies during 2009.

The following table sets forth, by level within the fair value hierarchy, the plans' assets at fair value as of December 31, 2009:

(millions)		Level 2
Money Market Fund	$	6
Common/Collective Trusts		678
Total investments at fair value	$	684

There are no assets classified as level 1 or level 3.

The GAC is an immediate participation guarantee contract. In accordance with the plan accounting guidance of the FASB ASC, the cost incurred to purchase the GAC prior to March 20, 1992, is permitted to be carried at contract value, since it is a contract with an insurance company and therefore is excluded from the table above. The cost incurred to fund the GAC after March 20, 1992, is carried at contract value in accordance with the plan accounting guidance of the FASB ASC, since it is a contract that incorporates mortality and morbidity risk. Contract value represents cost plus interest income less distributions for benefits and administrative expenses.

Contributions. The Company made a discretionary contribution to the pension plans of $33 million in 2009. Total contributions in 2009 equaled $35 million. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The Company made contributions totaling $41 million in January 2010.

The Company made contributions to its other postretirement benefit plans of $18 million in 2009 and $16 million in 2008. In 2010, the Company plans on making voluntary contributions to fund VEBA trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company's plans met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2009 and 2008.

Thrift Savings Plans. The Company has thrift savings plans under section 401(k) of the Internal Revenue Code. Under these plans, eligible employees may defer and contribute to the plans a portion of current compensation in order to provide future retirement benefits. The Company makes contributions to the plans by matching a portion of the employee's contributions. The costs of this matching were approximately $9 million and $10 million for 2009 and 2008, respectively.

The Company also makes contributions to retirement income accounts within its thrift savings plans for certain employees not covered by its noncontributory defined benefit pension plans. These employees consist mainly of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and it makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement equaled $1 million in 2009 and less than $1 million in 2008.

Note 10 - 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 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 2006 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments made by the IRS for the 2006 year were recorded in the 2008 financial statements. Tax years 2007 and 2008 were 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. Adjustments for 2007, agreed to in January 2009, were comprised of $5 million of depreciable temporary differences which were recorded in 2009. Areas remaining under examination for 2008 include bonus depreciation and the Company's application for a change in repair deductions. No net adverse impact is expected from these remaining areas.

The following table shows reductions of unrecognized tax benefits for the twelve months ended December 31, (in millions of $). There were no material additions in unrecognized tax benefits during either year.

	2009	2008
Balance at beginning of year	$8	$10
Reductions due to expiration of statute of limitations	(7)	(2)
Balance at end of year	$1	$8

Possible amounts of uncertain tax positions that may decrease within the next twelve months total $1 million and are based on the expiration of statutes during 2010. Of this amount, $1 million relates primarily to state income tax. If recognized, the $1 million of unrecognized tax benefits would reduce the effective tax rate.

Interest and penalties, if any, are recorded as operating expenses on the income statement and accrued expenses on the balance sheet. Interest expense related to unrecognized tax benefits of less than $1 million was accrued for 2009 and 2008, based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. No penalties have been accrued by the Company through December 31, 2009.

Components of income tax expense are shown in the table below for the year ended December 31, (in millions of $):

	2009	2008
Current	$39	$96
Deferred	46	(14)
Amortization of investment tax credit	(3)	(4)
Total income tax expense	$82	$78

In June 2006, LG&E and KU filed a joint application with the 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 and KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. This tax credit will be amortized following the plant being placed in service. The amortization will reduce income tax expense over the life of the related property. Based on eligible construction expenditures incurred, the Company recorded investment tax credits of $25 million and $33 million in 2009 and 2008, respectively. Including the 2009 credit, the maximum $125 million allowed for the project will be met. In addition, a full depreciation basis adjustment is required for this credit and will be reflected in tax expense over the life of the related projects.

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. During 2008 and 2009, the plaintiffs submitted amended complaints alleging additional claims for relief. In October 2009, the plaintiffs filed a motion for a preliminary injunction seeking temporary implementation of certain elements of the requested relief. The Company is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

Components of net deferred tax liabilities included in the balance sheets are shown below as of December 31, (in millions of $):

	2009	2008
Deferred tax liabilities:		
Depreciation and other plant-related items	$694	$660
Accruals and other assets	91	40
Investments and other financial assets	14	15
Total deferred tax liabilities	799	715
Deferred tax assets:		
Net operating loss carryforward	390	-
Advanced coal and other tax credit carryforwards	163	132
Pensions and similar obligations	93	95
Accruals and other liabilities	38	29
Income taxes due to customers	28	28
Investment tax credit	10	12
Investments and other financial assets	7	9
	729	305
Valuation allowance	(7)	-
Total deferred tax assets	722	305
Net deferred income tax liability (current and noncurrent)	$77	$410
Balance-sheet classification:		
Current assets	$10	$25
Noncurrent liabilities	87	435
Net deferred income tax liability (current and noncurrent)	$77	$410

Based on the Company's net deferred tax liability position, past performance history of subsidiaries and expectations of similar performance in the future, and the extensive realization period for net operating loss carryforwards, future taxable income of the Company will more likely than not be sufficient to realize fully the deferred tax assets associated with the net operating losses. The net operating loss carryforwards start to expire in 2024. Alternative minimum tax credits of $17 million do not expire, wind credits of $11 million start to expire in 2017, investment tax credits of $125 million start to expire in 2026 and other general business credits start to expire in 2018. A full valuation allowance has been provided for certain capital loss carryforwards that expire in 2014.

As discussed in Note 3, Discontinued Operations, the Company incurred losses in connection with the termination of the WKE lease. As a result, federal tax loss carryforwards were $336 million and state tax net operating loss carryforwards were $54 million as of December 31, 2009. There were no federal or state tax loss carryforwards as of December 31, 2008.

A reconciliation of differences between the statutory U.S. federal income tax rate and the Company's effective income tax rate as a percentage of income from continuing operations before income taxes follows:

	2009	2008
Statutory federal income tax rate	35.0%	35.0%
State income taxes, net of federal benefit	(0.6)	(0.2)
Equity investments	0.2	0.6
Reduction of income tax reserve	0.3	0.2
Investment and other tax credits	0.3	0.3
Goodwill impairment	(42.3)	(41.2)
Other differences – net	0.5	0.2
Effective income tax rate	(6.6)%	(5.1)%

Note 11 - Long-Term Debt

Long-term debt and the current portion of long-term debt, summarized below, consists primarily of pollution control bonds issued by LG&E and KU, loans from an affiliated company, and medium-term notes issued by Capital Corp. Utility debt issuance expense is capitalized in regulatory assets and amortized over the lives of the related bond issues for LG&E and KU, consistent with regulatory practices. Non-utility issuance expense is amortized using the effective interest rate method. Interest rates and maturities in the table below are for the amounts outstanding at December 31, 2009 and 2008, and include the impact of interest rate swaps in place.

	Stated Interest Rates	Weighted Average Interest Rate	Maturities	Principal Amounts (In Millions Of Dollars)
2009:				
Current	Variable-7.01%	2.42%	2010-2034	$707
Noncurrent	Variable-7.78%	4.24%	2011-2037	3,479
2008:				
Current	Variable-4.07%	2.26%	2009-2034	$604
Noncurrent	Variable-7.47%	4.85%	2010-2037	3,182

Under the provisions for LG&E's and KU's variable-rate pollution control bonds classified as current portion of long-term debt, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt. The following bond series are subject to tender for purchase:

LG&E:
Jefferson Co. 2001 Series A, due September 1, 2026, variable %
Trimble Co. 2001 Series A, due September 1, 2026, variable %
Jefferson Co. 2001 Series B, due November 1, 2027, variable %
Trimble Co. 2001 Series B, due November 1, 2027, variable %

KU:
Mercer Co. 2000 Series A, due May 1, 2023, variable %
Carroll Co. 2002 Series A, due February 1, 2032, variable %
Carroll Co. 2002 Series B, due February 1, 2032, variable %
Carroll Co. 2008 Series A, due February 1, 2032, variable %
Mercer Co. 2002 Series A, due February 1, 2032, variable %
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %
Carroll Co. 2004 Series A, due October 1, 2034, variable %
Carroll Co. 2006 Series B, due October 1, 2034, variable %

The average annualized interest rates for these bonds during 2009 were 1.06% and 0.61% for LG&E and KU, respectively. The average annualized interest rates for these bonds during 2008 were 2.34% and 1.75% for LG&E and KU, respectively.

Redemptions and maturities of long-term debt in 2009 and 2008 are summarized below (in millions of $):

Year	Company	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2009	E.ON U.S.	Due to Fidelia	$50	3.98%	Unsecured	2009
2009	E.ON U.S.	Due to Fidelia	$80	Variable	Unsecured	2009
2009	E.ON U.S.	Due to Fidelia	$50	Variable	Unsecured	2009
2009	E.ON U.S.	Due to Fidelia	$75	4.07%	Unsecured	2009
2008	KU	Pollution control bonds	$13	Variable	Unsecured	2035
2008	KU	Pollution control bonds	$13	Variable	Unsecured	2035
2008	KU	Pollution control bonds	$17	Variable	Unsecured	2036
2008	KU	Pollution control bonds	$17	Variable	Unsecured	2036
2008	Cap. Corp.	Medium-term notes	$24	6.46%	Unsecured	2008

Issuances of long-term debt in 2009 and 2008 are summarized below (in millions of $):

Year	Company	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2009	E.ON U.S.	Due to Fidelia	$50	7.78%	Unsecured	2011
2009	E.ON U.S.	Due to Fidelia	$50	Variable	Unsecured	2012
2009	E.ON U.S.	Due to Fidelia	$50	Variable	Unsecured	2012
2009	E.ON U.S.	Due to Fidelia	$100	Variable	Unsecured	2012
2009	E.ON U.S.	Due to Fidelia	$75	6.04%	Unsecured	2014
2009	E.ON U.S.	Due to Fidelia	$50	Variable	Unsecured	2014
2009	E.ON U.S.	Due to Fidelia	$50	Variable	Unsecured	2014
2009	E.ON U.S.	Due to Fidelia	$80	Variable	Unsecured	2016
2009	KU	Due to Fidelia	$50	5.28%	Unsecured	2017
2009	KU	Due to Fidelia	$50	4.81%	Unsecured	2019
2009	KU	Due to Fidelia	$50	4.45%	Unsecured	2019
2008	E.ON U.S.	Due to Fidelia	$100	Variable	Unsecured	2010
2008	E.ON U.S.	Due to Fidelia	$75	7.01%	Unsecured	2010
2008	E.ON U.S.	Due to Fidelia	$75	Variable	Unsecured	2015
2008	LG&E	Due to Fidelia	$50	6.48%	Unsecured	2015
2008	LG&E	Due to Fidelia	$25	6.21%	Unsecured	2018
2008	KU	Due to Fidelia	$75	7.04%	Unsecured	2018
2008	KU	Due to Fidelia	$50	6.16%	Unsecured	2018
2008	KU	Due to Fidelia	$50	5.65%	Unsecured	2018
2008	KU	Due to Fidelia	$75	5.85%	Unsecured	2023
2008	KU	Pollution control bonds	$78	Variable	Unsecured	2032

Acquisitions of outstanding pollution-control bonds and reissuances and retirements of reacquired pollution-control bonds in 2008 are summarized below (in millions of $):

Transaction Description	Company	Principal Amount	Rate	Secured/ Unsecured	Maturity
Acquisition	LG&E	$25	Variable	Unsecured	2027
Acquisition	LG&E	$31	Variable	Unsecured	2033
Acquisition	LG&E	$35	Variable	Unsecured	2033
Acquisition	LG&E	$128	Variable	Unsecured	2033
Acquisition	LG&E	$40	Variable	Unsecured	2035
Acquisition	KU	$13	Variable	Unsecured	2023
Acquisition	KU	$50	Variable	Unsecured	2034
Acquisition	KU	$17	Variable	Unsecured	2036
Reissuance	LG&E	$25	5.38%	Unsecured	2027
Reissuance	LG&E	$31	5.63%	Unsecured	2033
Reissuance	LG&E	$40	5.75%	Unsecured	2035
Reissuance	KU	$13	Variable	Unsecured	2023
Reissuance	KU	$50	Variable	Unsecured	2034
Retirement	KU	$17	Variable	Unsecured	2036

There were no acquisitions of outstanding pollution-control bonds and or reissuances and retirements of reacquired pollution-control bonds in 2009.

The proceeds of the 2009 KU loans were used to fund capital expenditures. The proceeds of the 2009 E.ON U.S. loans were used to refinance maturing loans from Fidelia, fund capital contributions to KU, fund discontinued operations, and fund contributions to the Company's pension and postretirement plans.

The proceeds of the 2008 LG&E and KU loans were used to fund capital expenditures. The proceeds of the 2008 E.ON U.S. loans were used to fund LG&E's and KU's capital expenditures and to fund discontinued operations.

Pollution control series bonds are obligations of LG&E or KU issued in connection with tax-exempt pollution control revenue bonds by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E or 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 LG&E or KU.

Several of the LG&E and 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 December 31, 2009, LG&E and KU had an aggregate $926 million of outstanding pollution control indebtedness ($163 million of which LG&E currently owns), of which $231 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 LG&E and KU 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 2009 and 2008, the average rate on LG&E's auction-rate bonds was 0.38% and 4.19%, respectively. The average rate on KU's auction-rate bonds was 0.44% and 4.50%, for 2009 and 2008, respectively. The instruments governing these auction rate bonds permit LG&E and 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 ratings on certain bonds 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. The following table presents the bonds downgraded (in millions of $):

			Moody's		S&P	
	Notes	Principal	2009	2008	2009	2008
LG&E:						
Trimble County 2000 Series A	-	83	A2	A2	BBB+	A
Jefferson Co. 2001 Series A	-	10	A2	A2	BBB+	A
Trimble County 2002 Series A	-	42	A2	A2	BBB+	A
Louisville Metro 2007 Series B	-	35	A2	A2	BBB+	A
Trimble County 2007 Series A	-	60	A2	A2	BBB+	A
KU:						
Carroll County 2002 Series C	-	96	A2	A2	BBB+	A
Carroll County 2007 Series A	-	18	A2	A2	BBB+	A
Trimble County 2007 Series A	-	9	A2	A2	BBB+	A

In March and April 2008, LG&E converted the Louisville Metro 2005 Series A and, 2007 Series A and B bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with the conversions, LG&E purchased the bonds from the remarketing agent. The Louisville Metro 2005 and 2007 Series A bonds were remarketed in November 2008, and the Company continues to hold the 2007 Series B bonds.

In May 2008, LG&E converted the Jefferson County 2000 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. In connection with the conversion, LG&E purchased the bonds from the remarketing agent. The bonds were remarketed in November 2008.

In July 2008, LG&E converted the Louisville Metro 2003 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. In connection with the conversion, LG&E purchased the bonds from the remarketing agent and continues to hold these bonds.

In November 2008, LG&E converted three pollution control bonds to a mode wherein the interest rate is fixed for an intermediate term, but not the full term of the bond. At the end of the intermediate term, the Company must remarket the bonds or buy them back. The terms of the November transactions are as follows (in millions of $):

Series	Principal	Interest Rate	End of Fixed-Rate Term
Jefferson County 2000 Series A	$25	5.375%	November 30, 2011
Louisville Metro 2007 Series A	31	5.625%	December 2, 2012
Louisville Metro 2005 Series A	40	5.750%	December 1, 2013

At the time of the conversion, the bond insurance policies that had been in place were terminated.

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 December 31, 2009, KU had no remaining repurchased bonds. During 2008, KU refinanced and remarketed $63 million and refinanced $17 million of pollution control bonds that it had previously repurchased.

As of December 31, 2009, LG&E continued to hold repurchased bonds in the amount of $163 million. The Company will hold some or all of such repurchased bonds until a later date, at which time it may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps the Company has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructuring or redemption and refinancing, could result in LG&E incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

All of LG&E's and KU's first mortgage bonds were released and terminated in April 2007 and February 2007, respectively. Only the tax-exempt pollution control revenue bonds issued by the counties remain. Under the provisions for certain of LG&E's and KU's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for LG&E's bonds subject to tender during 2009 and 2008 was 1.06% and

2.34%, respectively. The average annualized interest rate for KU's bonds subject to tender during 2009 and 2008 was .61% and 1.75%, respectively.

Interest rate swaps are used to hedge LG&E's underlying variable-rate debt obligations. These swaps hedge specific debt issuances and, consistent with management's designation, are accorded hedge accounting treatment. The swaps exchange floating-rate interest payments for fixed rate interest payments to reduce the impact of interest rate changes on LG&E's pollution control bonds. As of December 31, 2009 and 2008, LG&E had swaps with an aggregate notional value of $179 million. See Note 6, Financial Instruments.

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

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

As of December 31, 2009, $3.4 billion of unsecured notes payable was outstanding to the Company's affiliate, Fidelia, with interest rates ranging from 4.24% to 7.78% and maturities ranging from 2010 to 2037.

The lenders under the medium-term notes for Capital Corp. are entitled to the benefits of a Support Agreement with E.ON U.S. The Support Agreement generally provides that E.ON U.S. will provide Capital Corp. with the necessary funds and financial support to meet its obligations under the medium-term notes.

All debt covenants at E.ON U.S. subsidiaries were satisfied at December 31, 2009.

Long-term debt maturities for E.ON U.S. are shown below:

	External	Affiliated	Totals
2010	$-	$358	$358
2011	2	350	352
2012	-	450	450
2013	-	375	375
2014	-	375	375
Thereafter	(a) 763	1,513	2,276
Totals	$765	$3,421	$4,186

Notes:

(a) Includes long-term debt of $349 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2026 to 2034. The Company does not expect to pay these amounts in 2010.

Note 12 - Notes Payable

At December 31, 2009, E.ON U.S. had a line of credit with E.ON North America, an affiliate of E.ON, totaling $150 million. The line of credit is available for working capital needs. Unused capacity under the line totaled $37 million and $14 million at December 31, 2009 and 2008, respectively. The average interest rates on outstanding balances under this line of credit at December 31, 2009 and 2008, were 0.92% and 0.32%, respectively. In February 2010, this line was extended to February 2011. E.ON U.S. also had two short-term loans with Fidelia outstanding as of December 31, 2009 and 2008, totaling $163 million on each of those dates. The short-term loans were used to acquire repurchased bonds in the amount of $163 million remaining at LG&E. The average interest rates on these short-term loans at December 31, 2009 and 2008, were 1.47% and 3.48%, respectively.

In addition to the above revolving lines of credit, E.ON U.S. entered into a short-term loan in 2009 totaling $575 million with Fidelia. The loan matures in July 2010. The interest rate on the loan equals the three-month LIBOR rate plus 1.28%. The Company used the proceeds from the loan to make payments related to the termination agreement with BREC. See Note 3, Discontinued Operations.

At December 31, 2009 and 2008, LG&E maintained bilateral line-of-credit facilities, with unaffiliated financial institutions, totaling $125 million, which mature in June 2012. Unused capacity under the facilities totaled $125 million at December 31, 2009. The covenants under these revolving lines of credit require that (1) LG&E keep its debt-to-total-capitalization ratio under 70%, (2) E.ON must own directly or indirectly at least two-thirds of LG&E's voting stock, (3) LG&E maintain credit ratings of BBB- and Baa3 or better as determined by S&P and Moody's, and (4) LG&E cannot dispose of assets totaling more than 15% of total assets as of December 31, 2006.

At December 31, 2009 and 2008, KU maintained a line-of-credit facility, with an unaffiliated financial institution, totaling $35 million, which matures in June 2012. Unused capacity under the facility totaled $35 million at December 31, 2009. The covenants under this revolving line of credit require that (1) KU keep its debt-to-total-capitalization ratio under 70%, (2) E.ON must own directly or indirectly at least two-thirds of KU's voting stock, (3) KU maintain credit ratings of BBB- and Baa3 or better as determined by S&P and Moody's, and (4) KU cannot dispose of assets totaling more than 15% of total assets as of December 31, 2006.

In October 2008, KU closed on a $78 million bilateral line of credit which had a 364 day maturity. This facility was terminated in December 2008 and replaced by four new letter of credit facilities to allow issuance of letters of credit totaling $198 million to support tax-exempt bonds totaling $195 million of the $228 million of bonds that can be put back to KU. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment. The expiration date for the letters of credit has been extended to December 2010. The reimbursement agreements are identical and contain the following covenants:

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

At December 31, 2009, KU had no remaining capacity for letters of credit under these facilities and was in compliance with these covenants.

All notes payable covenants at E.ON U.S. subsidiaries were satisfied at December 31, 2009.

Note 13 - Commitments and Contingencies

Operating Leases

The Company leases office space, office equipment, plant equipment, real estate, railcars, telecommunications, vehicles, and a helicopter, and accounts for these leases as operating leases. See also Note 3, Discontinued Operations, for a discussion of the Big Rivers operating lease. Lease expense equaled $16 million in 2009 and $15 million in 2008. Commitments under operating leases as of December 31, 2009, are presented below (in millions of $):

2010	$13
2011	10
2012	9
2013	7
2014	7
Thereafter	7
Totals	$53

LG&E and KU are participants in a sale and leaseback transaction involving their two jointly-owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, LG&E and KU entered into a tax-efficient, 18-year lease of the CTs. LG&E and KU have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is the same as if LG&E and KU had retained their ownership interests. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

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

At December 31, 2009, the maximum aggregate amount of default fees or amounts was $8 million. Of this amount, LG&E would be responsible for approximately $3 million (38%) and KU would be responsible for approximately $5 million (62%). LG&E and KU have made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay any default fees or amounts that LG&E or KU may incur.

Letters of Credit

E.ON U.S. has provided a letter of credit securing off-balance sheet commitments totaling $8 million at December 31, 2009. The underlying obligation is a performance guarantee. LG&E has also issued letters of credit as of December 31, 2009, for off-balance sheet obligations totaling $4 million, and KU has issued a letter of credit as of the same date for off-balance sheet obligations of less than $1 million and for on-balance sheet obligations of $198 million to support outstanding bonds of $195 million.

Purchased Power

LG&E and KU have contracts for purchased power with OVEC, terminating in 2026, for various Mw capacities. LG&E and KU have investments of 5.63% and 2.5%, respectively, ownership in OVEC's common stock, which is accounted for on the cost method of accounting. LG&E's and KU's shares of OVEC's output is 5.63%, and 2.5%, respectively, which approximates 179 Mw of generation capacity.

KU also has a purchased-power arrangement with OMU. Under the OMU agreement, which will be terminated by OMU in May 2010, KU purchases all of the output not required by OMU of an approximately 400-Mw coal-fired generating station. The amount of purchased power available to KU during 2010, which is expected to be approximately 5% of KU's total Kwh native load energy requirements, is dependent upon a number of factors including the OMU units' availability, maintenance schedules, fuel costs and OMU requirements. Payments are based on the total costs of the station allocated per terms of the OMU agreement. Included in the total costs is KU's proportionate share of debt service requirements on $207 million of OMU bonds outstanding at December 31, 2009. The debt service is allocated to KU based on its annual allocated share of capacity, which averaged approximately 44% in 2009. KU does not guarantee the OMU bonds, or any requirements therein, in the event of default by OMU.

Future obligations for power purchases are shown in the following table (in millions of $):

2010	$37
2011	32
2012	34
2013	36
2014	38
Thereafter	575
Totals	$752

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.

Coal and Gas Purchase Commitments

The following table summarizes the Company's coal, natural gas, and natural gas transportation purchase commitments for periods after December 31, 2009 (in millions of $):

2010	$777
2011	637
2012	260
2013	224
2014	223
Thereafter	39
Total	$2,160

Obligations after 2014 are indexed to future market prices and are not included above since prices will be set in the future using the contracted methodology.

Construction Program

LG&E had $14 million of commitments in connection with its construction program at December 31, 2009, and KU had $62 million of commitments in connection with its construction program as of the same date.

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 and KU's shares of additional costs from inception of the contract through the expected project completion in 2010 are estimated to be approximately $5 million and $30 million, respectively. During late 2009 and early 2010, KU and LG&E received a number of contractual notices from the TC2 construction contractor claiming force majeure status with respect to certain events which, if granted, may affect the rights of the parties under other contract terms relating to pricing, commercial operations date, liquidated damages or other provisions. The parties are continuing to discuss such matters.

TC2 Air Permit

The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division for Air Quality ("KDAQ") in November 2005. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order, although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the two EPA objections. In March 2010, the Sierra Club submitted a petition the EPA to object to the permit revision. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the right to challenge the final permit expires, the Company cannot predict the final outcome of this matter.

Thermostat Replacement

During January 2010, LG&E and KU announced a voluntary plan to replace certain thermostats which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, LG&E and KU anticipate replacing up to approximately 14,000 thermostats. Estimated costs associated with the replacement program may be $2 million. However, LG&E and KU cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

Reserve Sharing Developments

The membership of LG&E and KU in the Midwest Contingency Reserve Sharing Group terminated on December 31, 2009. In December 2009, LG&E and KU entered into arrangements with Tennessee Valley Authority and East Kentucky Power Cooperative to form a new reserve sharing group, the TEE Contingency Reserve Sharing Group. Contingency reserves, including spinning reserves and supplemental reserves, relate to power or capacity requirements that LG&E and KU must have available for certain reliability purposes. In general, the operational and financial impact of reserve sharing arrangements varies based upon factors such as the terms of the agreement, the relative generating and operations conduct of the parties and relevant market prices. While LG&E and KU do not anticipate the revised reserve sharing developments will have a material adverse effect on their prospective operations or financial condition, such outcome cannot be guaranteed.

Mine Safety Compliance Costs

In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky, and other states that supply coal to LG&E and KU, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of the majority of the long-term coal contracts that LG&E and KU have in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. LG&E's and KU's coal suppliers regularly submit price adjustments related to these compliance costs. LG&E and KU employ an external consultant to review all relevant mine safety compliance cost claims for validity and reasonableness. Depending upon the terms of the contracts and commercial practice, LG&E and KU may delay payment of the adjustments or pay certain adjustments subject to refund. At appropriate times in the review, payment or refund processes, LG&E and KU may make adjustments to the values or amounts of inventory, accounts receivable or accounts payable relating to coal matters. In general, LG&E and KU expect to recover these coal-related cost adjustments through the FAC.

Environmental

LG&E's and KU'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 and 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, LG&E's and KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In January 2010, the EPA issued a proposed rule to reconsider the NAAQS for Ozone, previously revised in 2008. The proposal would institute more stringent standards. At present, the Company 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 and KU are also reviewing aspects of their compliance plans 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 and KU are 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 their financial or operational conditions.

Hazardous Air Pollutants. As provided in the Clean Air Act, as amended, 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 and KU are not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on their financial or operational conditions.

Acid Rain Program. The Clean Air Act, as amended, 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 Clean Air Act, as amended, also contains requirements for power plants to reduce NOx emissions through the use of available combustion controls.

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

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. 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. KU's strategy for its Phase II SO_2 requirements, which also 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 mandated by the NOx SIP Call and associated obligations, LG&E and KU installed additional NOx controls, including SCR technology, during the 2000-through-2009 time period at a cost of $197 million and $221 million, respectively. In 2001, the Kentucky Commission granted approval to recover the costs incurred by LG&E and KU 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 and KU expect to incur additional capital expenditures totaling approximately $85 million and $320 million, respectively, during the 2010 through 2012 time period for pollution control equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by LG&E and KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. LG&E and KU believe their 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 and 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. LG&E and KU will continue to monitor these developments to ensure that their environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

GHG Developments. 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. At Copenhagen, the U.S. provided voluntary agreements to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico, in late 2010 to continue toward a binding agreement.

GHG Legislation. LG&E and KU are 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, (H.R. 2454), 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.

In September 2009, the Clean Energy Jobs and American Power Act (S. 1733), which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision has incorporated allowance allocation provisions similar to the House bill. The Company is closely monitoring the progress of the legislation, although the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. 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 was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. Also in September 2009, the EPA proposed to require new or modified sources with GHG emissions equivalent to at least 10,000 to 25,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the proposed rule. A final rule is expected in 2010.

The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. As companies with significant coal-fired generating assets, LG&E and KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on their operations, 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.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. The Company was included as defendant in the complaint, but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. LG&E and KU are currently unable to predict further developments in the Comer case, including whether the plaintiffs will continue with a previously-dismissed motion seeking to amend their complaint to add the Companies as parties. LG&E and KU continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

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 KU 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, KU reached a tentative settlement with the government resolving all outstanding claims. The proposed consent decree, which was approved by the court in March 2009, 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.

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.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and

3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

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. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, KU received an EPA settlement proposal providing for imposition of additional permit limits and emission controls. The Company anticipates continued settlement negotiations with EPA. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures by KU. KU is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon KU's financial position or results of operations.

In March 2010, KU received an EPA settlement proposal providing for imposition of additional permit limits and emission controls. The Company anticipates continued settlement negotiations with EPA. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures by KU. 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.

Ash Ponds, Coal-Combustion Byproducts and Water Discharges. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including LG&E and KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of LG&E's and KU's impoundments, which the EPA found to be in satisfactory condition. The Company is awaiting final inspection reports for additional impoundments. The EPA and other agencies are currently considering the need to revise applicable standards governing the structural integrity of ash ponds and other impoundments. In addition, the EPA has announced that it is re-evaluating current regulatory requirements applicable to coal combustion byproducts and anticipates proposing new rules by early 2010. The EPA is considering a wide range of regulatory options including subjecting ash ponds and landfills handling coal combustion byproducts to regulation under the hazardous waste program. Finally, the EPA has announced plans to develop revised effluent limitations guidelines and standards governing discharges from power plants. The Company is monitoring these ongoing regulatory developments, but will be unable to determine the impact until such time as new rules are finalized.

General Environmental Proceedings. From time to time, LG&E and KU appear 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, a completed settlement with state regulators regarding particulate limits in the air permit for KU's Tyrone generating station, remediation activities for, or other risks relating to elevated Polychlorinated Biphenyl ("PCB") levels at existing properties, activities for former manufactured gas plant sites or liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; or on-going claims regarding alleged particulate emissions from LG&E's Cane Run station and claims regarding GHG emissions from LG&E's and KU'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 or KU. The Company is currently conducting remediation of certain contamination existing or occurring at a former mid-stream gas gathering and processing sites in Texas, which it sold during 2000.

Argentina Matters

In December 2001, the Company commenced arbitration proceedings against the Republic of Argentina under the U.S.-Argentina Bilateral Investment Treaty before the ICSID. The arbitration presents claims relating to the diminution in value of the former investments of the Company in Argentina due to certain prejudicial actions of the Argentine government. In July 2007, the panel issued an order awarding E.ON U.S. $57 million (including interest) for the period through February 2005. In July 2007, the panel denied an E.ON U.S. request for additional damages of approximately $56 million for the period March 2005 - July 2007. In August and November 2008, E.ON U.S. and the Argentine government submitted respective petitions for annulment of elements of the prior decisions. Since late 2008, in connection with on-going interim and final gas tariff renegotiation processes in Argentina, the parties have agreed to a temporary suspension and potential dismissal of the ICSID proceeding, subject to certain conditions. E.ON Spain has assumed relevant rights and obligations with respect to claims and liabilities relating to the Argentine businesses in connection with the 2010 transfer such businesses to E.ON Spain.

During November 2008, the Argentine Central Bank commenced an administrative proceeding alleging a violation of certain emergency currency exchange laws in place during the country's economic crisis in connection with a December 2002 refinancing by Centro of $35 million of a previously-existing, maturing loan. Centro and its individual directors have filed responsive pleadings in the matter and requested dismissal at the administrative phase. In April 2010, the Argentine Central Bank staff issued a ruling declining to dismiss the case at the conclusion of the administrative stage and therefore forwarded the matter to a specialized financial criminal court where further proceedings will continue. A subsidiary of E.ON U.S. has entered into indemnity agreements with certain associated directors. E.ON Spain has assumed relevant rights and obligations with respect to claims and liabilities relating to the Argentine businesses in connection with its purchase of the business in 2010.

Guarantees

In connection with various divestitures, the Company has indemnified/guaranteed respective parties against certain liabilities that may arise in connection with these transactions and business activities. The terms of these indemnifications/guarantees vary, as do the expiration terms. In addition, the Company indemnifies its duly elected or appointed directors and officers against liabilities incurred as a result of their activities for the Company, such as adverse judgments relating to litigation matters. If the indemnified party were to incur a liability or have a liability increase as a result of a successful claim, pursuant to the terms of the indemnification, the Company would be required to reimburse the indemnified party. The maximum amount of potential future payments is generally unlimited. The carrying amount recorded for all indemnifications/guarantees as of December 31, 2009 was $85.6 million, and relate to WKE. There was no accrual for 2008.

In connection with the WKE transaction, see Note 3, Discontinued Operations, WKE indemnified the purchaser against certain liabilities primarily related to litigation from third parties. The estimated fair value of this indemnity obligation is $10.8 million and is included in the indemnifications/guarantees balance of $85.6 million at December 31, 2009. Additionally, regarding the WKE transaction, a direct financial guarantee in the form of a swap was issued to a third party customer. The estimated fair value of this guarantee is $74.8 million and is included in the indemnifications/guarantees balance of $85.6 million at December 31, 2009. The Company has issued direct financial guarantees to all parties involved guaranteeing the due and punctual payment, performance and discharge by each WKE Party of its respective present and future obligations. The most comprehensive of these guarantees is the parental guarantee covering the WKE Transaction Termination Agreement, which has a term of 12 years beginning on July 16, 2009. Among other matters, such obligations include indemnities regarding operational, regulatory or environmental matters, if any, relating to the Company's completed leasing and operating period. The obligation valuations were calculated based on management's best estimated of the value expected to be required to issue the indemnifications in a standalone, arm's length transaction with an unrelated party and, where appropriate, by the utilization of probability weighted discounted net cash flow models.

Additionally, the Company has indemnified various third parties related to historical obligations for divested subsidiaries and affiliates. The indemnifications vary by entity and the maximum amount limits range from being capped at the purchase price to no specified maximum; however, the Company is not aware of claims made by any party at this time. The Company would be required to perform on these indemnifications in the event of default by the indemnified party. No additional material loss is anticipated by reason of such indemnifications.

Note 14 - Jointly Owned Electric Utility Plants

Trimble County Unit 1

LG&E owns a 75% undivided interest in Trimble County Unit 1, which the Kentucky Commission has allowed to be reflected in customer rates. Of the remaining 25% of the unit, IMEA owns a 12.12% undivided interest, and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate ownership share of fuel cost, operation and maintenance expenses, and incremental assets.

The following data represents shares of the jointly owned property (based on nameplate rating):

	Trimble County 1			
	LG&E	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	425	73	68	566
(in millions of $):				
LG&E's 75% ownership:				
Plant held for future use	$503			
Construction work in progress	22			
Accumulated depreciation	213			
Net book value	$312			

Trimble County Unit 2

LG&E and KU are nearing completion of TC2, a jointly-owned unit at the Trimble County site. LG&E and KU own undivided interests of 14.25% and 60.75%, respectively, in the unit. Of the remaining 25% of the unit, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance costs when the unit begins operation, which is expected to occur in 2010.

The following data represents shares of the jointly owned property:

	TC2			
	LG&E And KU	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	628	108	102	838
(in millions of $):				
LG&E's 75% ownership:				
Plant held for future use	$126			
Construction work in progress	848			
Accumulated depreciation	65			
Net book value	$909			

Note 15 - Accumulated Other Comprehensive Income

Accumulated other comprehensive income consisted of the following (in millions of $):

	Funded Status Of Pension And Postretirement Plans		Accumulated Derivative Gain or Loss		Foreign Currency Translation Adj.		Totals		
	Pretax	Tax	Pretax	Tax	Pretax	Tax	Pretax	Tax	Net
Balance at December 31, 2007	$(32)	$12	$(11)	$4	$22	$(4)	$(21)	$12	$(9)
Change in funded status of defined-benefit pension and postretirement plans	(77)	31	-	-	-	-	(77)	31	(46)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	-	-	(2)	-	-	-	(2)	-	(2)
Foreign currency translation adjustment	-	-	-	-	(5)	1	(5)	1	(4)
Balance at December 31, 2008	(109)	43	(13)	4	17	(3)	(105)	44	(61)
Change in funded status of defined-benefit pension and postretirement plans	29	(11)	-	-	-	-	29	(11)	18
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	-	-	5	(2)	-	-	5	(2)	3
Foreign currency translation adjustment	-	-	-	-	(4)	1	(4)	1	(3)
Balance at December 31, 2009	$(80)	$32	$(8)	$2	$13	$(2)	$(75)	$32	$(43)

Note 16 - Share Performance Plan

In 2006, the Company introduced a stock-based compensation system, the E.ON Share Performance Plan, and virtual shares were granted under the Plan to certain executives of the Company. The Plan is a stock-based compensation plan based on the value of E.ON's shares, and it entitles each participant to receive a payment at the end of a three-year period equal to a target value per share times the number of virtual shares granted. The number of virtual shares can not change during the three-year period, but the target value per share can change based on E.ON's stock price and the performance of E.ON stock during the three-year period compared to the change in the Dow Jones STOXX Utilities Index (Total Return EUR). The Company uses the fair-value method to account for the Plan. See Note 7, Fair Value Measurements.

The table below shows the number of virtual shares issued to E.ON U.S. executives and outstanding under the E.ON Share Performance Plan:

	Virtual Shares Granted	Target Price
2006	8,725	€79.22
2007	6,830	96.52
2008	5,537	136.26
2009	30,040	27.93
2010	27,643	27.25

The 2006 grant was paid out in 2009, and the 2007 grant was paid out in January 2010. On August 31, 2008, E.ON AG stock shares were split three for one. This split was reflected in the 2009 and 2010 grants.

The Company recorded expense of less than $1 million related to the Plan in 2009, and it recorded income of less than $1 million in 2008.

Note 17 – Subsequent Events

Subsequent events have been evaluated through April 27, 2010, the date of issuance of these statements and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On April 15, 2010, the Company made a discretionary contribution to its WKE Union pension plan totaling $3.3 million.

On March 24, 2010, LG&E and KU delivered notices of termination under provisions of the wind power contracts permitting termination if certain conditions precedent were not accomplished by a fixed date. The Companies also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding.

On March 4, 2010, the Virginia Commission approved the stipulation related to the rate increase filing with rates to become effective in April 2010.

On January 29, 2010, LG&E and KU filed an application with the Kentucky Commission requesting increases in annual electric base rates of $95 million and $135 million, respectively, or approximately 12% each. At the same time, LG&E filed an application with the Kentucky Commission requesting an increase in gas base rates of $23 million annually or approximately 8%. LG&E and KU has requested the increases based on the twelve month test year ended October 31, 2009. LG&E and KU requested new base rates to become effective on and after March 1, 2010. Under Kentucky Commission practice, the requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding.

On January 13, 2010, the Company made discretionary contributions to its pension plans totaling $41 million.

On January 1, 2010, the Company sold its interests in Centro and Cuyana to an affiliate of E.ON AG for a total of $35 million. See Note 3, Discontinued Operations.

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Report of Independent Auditors

To the Board of Directors and Management of E.ON U.S. LLC

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of capitalization, operations, comprehensive loss, retained earnings, and cash flows present fairly, in all material respects, the financial position of E.ON U.S. LLC and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

April 27, 2010