COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	**CASE NO.**
COMPANY FOR AN ADJUSTMENT OF	**)**	**2012-00221**
ITS ELECTRIC RATES	**)**	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
COMMISSION STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 28, 2012

FILED: SEPTEMBER 12, 2012

VERIFICATION

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

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Tosca A. Henry (SEAL)

Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

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

The undersigned, **Cheryl E. Bruner**, being duly sworn, deposes and says that she is Director – Customer Service & Marketing for LG&E and KU Services Company, 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.

Cheryl E. Bruner

Cheryl E. Bruner

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Joan A. Henry (SEAL)

Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director, Accounting and Regulatory Reporting for LG&E and KU Services Company, 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 10th day of September 2012.

(SEAL)
Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

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

The undersigned, **Sidney L. "Butch" Cockerill**, being duly sworn, deposes and says that he is Director – Operating Services and Business Process Management for LG&E and KU Services Company, 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.

Sidney L. "Butch" Cockerill
____
Sidney L. "Butch" Cockerill

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Joan A. Henry
______________________(SEAL)
Notary Public

My Commission Expires:

July 21, 2015
____

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for LG&E and KU Services Company, 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.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

_________________________(SEAL)
Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Chris Hermann**, being duly sworn, deposes and says that he is Senior Vice President, Energy Delivery for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 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.

C Hermann

Chris Hermann

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Notary Public (SEAL)

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is the Senior Vice President, Valuation and Rate Division, for Gannett Fleming, Inc., 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.

John J. Spanos
JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 30th day of August 2012.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2015

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2015
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Senior Vice President, Energy Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 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.

Paul W. Thompson

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 1

Responding Witness: Robert M. Conroy

Q-1. Refer to the Testimony of Robert M. Conroy ("Conroy Testimony"), Conroy Exhibit R2. Provide this schedule for each of the following rate classes: GS, AES, PS-Secondary, PS-Primary, TOD-Secondary, TOD-Primary, RTS, and FLS.

A-1. The requested information is contained in "Att-PSC2-75-File04" ('C-3, C-4 KU Electric Cost of Service Study.xls'); however, certain cells were not updated to include the final results of the cost of service study. KU is providing in Excel format an updated cost of service spreadsheet ('C-3, C-4 KU Electric Cost of Service Study Revised.xlsx'), which incorporates other corrections to the study identified through discovery. The revisions have an immaterial impact on the results of the cost of service study. See the attachment for exhibits similar to Conroy Exhibit R2 for each of the above referenced rate classes. Rate class RS is also included in the attachment in order to reflect the impact of the changes made to the cost of service study.

One attachment is being provided in a separate file in Excel format.

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate Residential Service

	Production		Transmission	Distribution		Customer Service Expenses	
Description	**Demand-Related**	**Energy-Related**	**Demand-Related**	**Demand-Related**	**Customer-Related**	**Customer-Related**	**Total**
(1) Rate Base	$ 914,490,029	$ 22,130,120	$ 121,147,430	$ 181,337,903	$ 305,318,006	$ 4,315,497	$ 1,548,738,986
(2) Rate Base Adjustments	(44,781,093)	(1,083,676)	(5,932,393)	(8,879,823)	(14,950,927)	(211,323)	$ (75,839,235)
(3) Rate Base as Adjusted	$ 869,708,936	$ 21,046,444	$ 115,215,037	$ 172,458,080	$ 290,367,079	$ 4,104,174	$ 1,472,899,751
(4) Rate of Return	5.58%	5.58%	5.58%	5.58%	5.58%	5.58%	
(5) Return	$ 48,555,066	$ 1,175,004	$ 6,432,352	$ 9,628,179	$ 16,210,932	$ 229,132	$ 82,230,665
(6) Interest Expenses	$ 15,722,568	$ 380,477	$ 2,082,853	$ 3,117,691	$ 5,249,246	$ 74,195	$ 26,627,031
(7) Net Income	$ 32,832,498	$ 794,527	$ 4,349,498	$ 6,510,488	$ 10,961,686	$ 154,937	$ 55,603,634
(8) Income Taxes	$ 19,815,192	$ 479,516	$ 2,625,025	$ 3,929,234	$ 6,615,638	$ 93,508	$ 33,558,113
(9) Operation and Maintenance Expenses	$ 35,811,223	$ 204,629,937	$ 11,753,875	$ 15,171,866	$ 30,645,559	$ 34,538,081	$ 332,550,542
(10) Depreciation Expenses	$ 47,987,589	$ -	$ 4,143,897	$ 8,039,537	$ 13,528,201	$ -	$ 73,699,224
(11) Other Taxes	$ 5,720,586	$ (257)	$ 1,011,276	$ 1,381,075	$ 2,323,947	$ -	$ 10,436,627
(12) Curtailable Service Credit	$ 2,422,409						$ 2,422,409
(13) Expense Adjustments - Prod. Demand	$ (3,527,954)	$ -	$ -	$ -	$ -	$ -	$ (3,527,954)
(14) Expense Adjustments - Energy	$ -	$ (5,076,645)	$ -	$ -	$ -	$ -	$ (5,076,645)
(15) Expense Adjustments - Trans. Demand	$ -	$ -	$ (1,911,652)	$ -	$ -	$ -	$ (1,911,652)
(16) Expense Adjustments - Distribution	$ -	$ -	$ -	$ (3,967,913)	$ (6,680,761)	$ -	$ (10,648,673)
(17) Expense Adjustments - Other	$ (725,103)	$ (17,547)	$ (96,058)	$ (143,784)	$ (242,088)	$ (3,422)	$ (1,228,002)
(18) Expense Adjustments - Total	$ (4,253,057)	$ (5,094,192)	$ (2,007,710)	$ (4,111,696)	$ (6,922,849)	$ (3,422)	$ (22,392,925)
(19) Total Cost of Service	$ 156,059,008	$ 201,190,008	$ 23,958,715	$ 34,038,195	$ 62,401,429	$ 34,857,300	$ 512,504,656
(20) Less: Misc Revenue - Tran. Demand		$ -	$ (4,144,146)	$ -	$ -	$ -	$ (4,144,146)
(21) Less: Misc Revenue - Energy	$ -	$ (9,697,329)	$ -	$ -	$ -	$ -	$ (9,697,329)
(22) Less: Misc Revenue - Other	$ (4,923,465)	$ (119,145)	$ (652,238)	$ (976,294)	$ (1,643,782)	$ (23,234)	$ (8,338,159)
(23) Less: Misc Revenue - Total	$ (4,923,465)	$ (9,816,474)	$ (4,796,384)	$ (976,294)	$ (1,643,782)	$ (23,234)	$ (22,179,634)
(24) Net Cost of Service	$ 151,135,543	$ 191,373,534	$ 19,162,331	$ 33,061,901	$ 60,757,647	$ 34,834,066	$ 490,325,022
(25) Billing Units	5,944,171,807	5,944,171,807	5,944,171,807	5,944,171,807	5,044,174	5,044,174	
(26) Unit Costs	0.025425837	0.032195155	0.003223718	0.00556207	$ 12.05	$ 6.91	$ 18.95

Customer Charge	$	18.95
Energy Charge		0.06641
Distribution Customer	$	18.95
Distribution Customer Ma		1.06
	$	20.01

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate General Service

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 271,406,661	$ 7,083,626	$ 35,954,705	$ 49,853,316	$ 77,702,883	$ 1,686,910	$ 443,688,101
(2)	Rate Base Adjustments	(13,786,658)	(359,827)	(1,826,393)	(2,532,401)	(3,947,077)	(85,690)	$ (22,538,046)
(3)	Rate Base as Adjusted	$ 257,620,004	$ 6,723,798	$ 34,128,312	$ 47,320,915	$ 73,755,805	$ 1,601,220	$ 421,150,055
(4)	Rate of Return	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	
(5)	Return	$ 25,687,437	$ 670,434	$ 3,402,953	$ 4,718,395	$ 7,354,233	$ 159,659	$ 41,993,112
(6)	Interest Expenses	$ 4,650,615	$ 121,380	$ 616,092	$ 854,248	$ 1,331,457	$ 28,906	$ 7,602,697
(7)	Net Income	$ 21,036,822	$ 549,054	$ 2,786,861	$ 3,864,147	$ 6,022,777	$ 130,753	$ 34,390,415
(8)	Income Taxes	$ 13,827,419	$ 360,891	$ 1,831,793	$ 2,539,889	$ 3,958,747	$ 85,943	$ 22,604,682
(9)	Operation and Maintenance Expenses	$ 10,628,224	$ 65,499,954	$ 3,488,371	$ 4,331,742	$ 7,464,992	$ 13,491,895	$ 104,905,178
(10)	Depreciation Expenses	$ 14,241,983	$ -	$ 1,229,845	$ 2,209,749	$ 3,439,497	$ -	$ 21,121,074
(11)	Other Taxes	$ 1,697,782	$ (82)	$ 300,131	$ 379,603	$ 590,855	$ -	$ 2,968,289
(12)	Curtailable Service Credit	$ 700,281						$ 700,281
(13)	Expense Adjustments - Prod. Demand	$ (1,641,706)	$ -	$ -	$ -	$ -	$ -	$ (1,641,706)
(14)	Expense Adjustments - Energy	$ -	$ (1,653,508)	$ -	$ -	$ -	$ -	$ (1,653,508)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (567,349)	$ -	$ -	$ -	$ (567,349)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (1,126,778)	$ (1,756,230)	$ -	$ (2,883,008)
(17)	Expense Adjustments - Other	$ (1,012,778)	$ (26,433)	$ (134,168)	$ (186,032)	$ (289,955)	$ (6,295)	$ (1,655,661)
(18)	Expense Adjustments - Total	$ (2,654,484)	$ (1,679,941)	$ (701,517)	$ (1,312,810)	$ (2,046,185)	$ (6,295)	$ (8,401,232)
(19)	Total Cost of Service	$ 64,128,643	$ 64,851,256	$ 9,551,576	$ 12,866,568	$ 20,762,140	$ 13,731,202	$ 185,891,384
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (1,229,919)	$ -	$ -	$ -	$ (1,229,919)
(21)	Less: Misc Revenue - Energy	$ -	$ (3,075,378)	$ -	$ -	$ -	$ -	$ (3,075,378)
(22)	Less: Misc Revenue - Other	$ (905,123)	$ (23,623)	$ (119,907)	$ (166,258)	$ (259,134)	$ (5,626)	$ (1,479,670)
(23)	Less: Misc Revenue - Total	$ (905,123)	$ (3,099,001)	$ (1,349,826)	$ (166,258)	$ (259,134)	$ (5,626)	$ (5,784,967)
(24)	Net Cost of Service	$ 63,223,519	$ 61,752,255	$ 8,201,750	$ 12,700,310	$ 20,503,006	$ 13,725,577	$ 180,106,417
(25)	Billing Units	1,902,668,718	1,902,668,718	1,902,668,718	1,902,668,718	984,828	984,828	
(26)	Unit Costs	0.033228864	0.0324556	0.004310656	0.006674998	20.82	13.94	$ 34.76

Customer Charge	$	34.76
Energy Charge		0.076670118
Distribution Customer	$	34.76
Distribution Customer Margi		3.47
	$	38.22

Attachment to Response to KU PSC-3 Question No. 1
Page 2 of 9
Conroy

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate All Electric School

	Description	Production Demand-Related	Production Energy-Related	Transmission Demand-Related	Distribution Demand-Related	Distribution Customer-Related	Customer Service Expenses Customer-Related	Total
(1)	Rate Base	$ 18,668,508	$ 585,389	$ 2,473,118	$ 4,057,269	$ 694,721	$ 66,084	$ 26,545,089
(2)	Rate Base Adjustments	(1,077,510)	(33,788)	(142,744)	(234,178)	(40,098)	(3,814)	$ (1,532,131)
(3)	Rate Base as Adjusted	$ 17,590,997	$ 551,602	$ 2,330,374	$ 3,823,092	$ 654,623	$ 62,269	$ 25,012,958
(4)	Rate of Return	8.85%	8.85%	8.85%	8.85%	8.85%	8.85%	
(5)	Return	$ 1,556,745	$ 48,815	$ 206,230	$ 338,331	$ 57,932	$ 5,511	$ 2,213,565
(6)	Interest Expenses	$ 317,773	$ 9,964	$ 42,097	$ 69,062	$ 11,825	$ 1,125	$ 451,847
(7)	Net Income	$ 1,238,973	$ 38,851	$ 164,133	$ 269,269	$ 46,107	$ 4,386	$ 1,761,718
(8)	Income Taxes	$ 747,956	$ 23,454	$ 99,086	$ 162,555	$ 27,834	$ 2,648	$ 1,063,532
(9)	Operation and Maintenance Expenses	$ 731,055	$ 5,412,903	$ 239,945	$ 372,434	$ 90,043	$ 525,859	$ 7,372,239
(10)	Depreciation Expenses	$ 979,624	$ -	$ 84,594	$ 179,780	$ 30,522	$ -	$ 1,274,520
(11)	Other Taxes	$ 116,781	$ (7)	$ 20,644	$ 30,883	$ 5,243	$ -	$ 173,545
(12)	Curtailable Service Credit	$ 43,630						$ 43,630
(13)	Expense Adjustments - Prod. Demand	$ (78,630)	$ -	$ -	$ -	$ -	$ -	$ (78,630)
(14)	Expense Adjustments - Energy	$ -	$ (138,212)	$ -	$ -	$ -	$ -	$ (138,212)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (39,025)	$ -	$ -	$ -	$ (39,025)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (33,041)	$ (5,658)	$ -	$ (38,699)
(17)	Expense Adjustments - Other	$ 26,775	$ 840	$ 3,547	$ 5,819	$ 996	$ 95	$ 38,071
(18)	Expense Adjustments - Total	$ (51,855)	$ (137,373)	$ (35,478)	$ (27,222)	$ (4,661)	$ 95	$ (256,494)
(19)	Total Cost of Service	$ 4,123,936	$ 5,347,792	$ 615,022	$ 1,056,761	$ 206,913	$ 534,112	$ 11,884,536
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (84,599)	$ -	$ -	$ -	$ (84,599)
(21)	Less: Misc Revenue - Energy	$ -	$ (249,095)	$ -	$ -	$ -	$ -	$ (249,095)
(22)	Less: Misc Revenue - Other	$ (16,334)	$ (512)	$ (2,164)	$ (3,550)	$ (608)	$ (58)	$ (23,225)
(23)	Less: Misc Revenue - Total	$ (16,334)	$ (249,608)	$ (86,763)	$ (3,550)	$ (608)	$ (58)	$ (356,920)
(24)	Net Cost of Service	$ 4,107,602	$ 5,098,185	$ 528,259	$ 1,053,211	$ 206,305	$ 534,054	$ 11,527,617
(25)	Billing Units	157,236,166	157,236,166	157,236,166	157,236,166	7,716	7,716	
(26)	Unit Costs	0.026123774	0.032423742	0.003359653	0.006698276	26.74	69.21	$ 95.95

Customer Charge	$	95.95
Energy Charge		0.068605
Distribution Customer	$	95.95
Distribution Customer Margi		8.49
	$	104.44

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31. 2012

Rate Power Service Secondary

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 352,139,842	$ 11,402,823	$ 46,649,866	$ 49,078,131	$ 7,168,404	$ 289,154	$ 466,728,220
(2)	Rate Base Adjustments	$ (21,610,113)	$ (699,768)	$ (2,862,808)	$ (3,011,826)	$ (439,911)	$ (17,745)	$ (28,642,171)
(3)	Rate Base as Adjusted	$ 330,529,729	$ 10,703,055	$ 43,787,057	$ 46,066,305	$ 6,728,493	$ 271,410	$ 438,086,049
(4)	Rate of Return	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	
(5)	Return	$ 36,819,910	$ 1,192,285	$ 4,877,732	$ 5,131,633	$ 749,532	$ 30,234	$ 48,801,326
(6)	Interest Expenses	$ 5,986,240	$ 193,844	$ 793,030	$ 834,309	$ 121,860	$ 4,916	$ 7,934,198
(7)	Net Income	$ 30,833,670	$ 998,441	$ 4,084,703	$ 4,297,324	$ 627,672	$ 25,319	$ 40,867,128
(8)	Income Taxes	$ 19,632,119	$ 635,718	$ 2,600,773	$ 2,736,151	$ 399,645	$ 16,121	$ 26,020,526
(9)	Operation and Maintenance Expenses	$ 13,789,717	$ 105,438,154	$ 4,526,028	$ 4,450,804	$ 991,955	$ 2,314,190	$ 131,510,848
(10)	Depreciation Expenses	$ 18,478,432	$ -	$ 1,595,678	$ 2,174,836	$ 315,449	$ -	$ 22,564,395
(11)	Other Taxes	$ 2,202,808	$ (132)	$ 389,409	$ 373,605	$ 54,189	$ -	$ 3,019,879
(12)	Curtailable Service Credit	$ 805,162						$ 805,162
(13)	Expense Adjustments - Prod. Demand	$ (1,743,615)	$ -	$ -	$ -	$ -	$ -	$ (1,743,615)
(14)	Expense Adjustments - Energy	$ -	$ (2,672,429)	$ -	$ -	$ -	$ -	$ (2,672,429)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (736,114)	$ -	$ -	$ -	$ (736,114)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (452,852)	$ (66,144)	$ -	$ (518,996)
(17)	Expense Adjustments - Other	$ (1,414,198)	$ (45,794)	$ (187,346)	$ (197,098)	$ (28,788)	$ (1,161)	$ (1,874,387)
(18)	Expense Adjustments - Total	$ (3,157,813)	$ (2,718,223)	$ (923,460)	$ (649,950)	$ (94,932)	$ (1,161)	$ (7,545,540)
(19)	Total Cost of Service	$ 88,570,335	$ 104,547,801	$ 13,066,160	$ 14,217,079	$ 2,415,837	$ 2,359,383	$ 225,176,596
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (1,595,774)	$ -	$ -	$ -	$ (1,595,774)
(21)	Less: Misc Revenue - Energy	$ -	$ (4,836,680)	$ -	$ -	$ -	$ -	$ (4,836,680)
(22)	Less: Misc Revenue - Other	$ (392,182)	$ (12,699)	$ (51,954)	$ (54,659)	$ (7,984)	$ (322)	$ (519,800)
(23)	Less: Misc Revenue - Total	$ (392,182)	$ (4,849,380)	$ (1,647,728)	$ (54,659)	$ (7,984)	$ (322)	$ (6,952,254)
(24)	Net Cost of Service	$ 88,178,154	$ 99,698,422	$ 11,418,432	$ 14,162,420	$ 2,407,854	$ 2,359,061	$ 218,224,342
(25)	Billing Units	8,750,756	3,062,809,438	8,750,756	8,750,756	67,524	67,524	
(26)	Unit Costs	$ 10.08	$ 0.03255	$ 1.30	$ 1.62	$ 35.66	$ 34.94	$ 70.60

Customer Charge	$	70.60
Energy Charge		0.032551
Demand Charge	$	13.00
Distribution Customer	$	70.60
Distribution Customer Margin		7.86
	$	78.46

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31. 2012

Rate Power Service Primary

	Production		Transmission	Distribution		Customer Service Expenses	
Description	Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1) Rate Base	$ 80,751,579	$ 2,607,305	$ 10,697,598	$ 8,777,383	$ 1,123,899	$ 15,313	$ 103,973,077
(2) Rate Base Adjustments	(5,091,908)	(164,407)	(674,553)	(553,471)	(70,869)	(966)	$ (6,556,173)
(3) Rate Base as Adjusted	$ 75,659,671	$ 2,442,898	$ 10,023,045	$ 8,223,912	$ 1,053,030	$ 14,348	$ 97,416,904
(4) Rate of Return	10.19%	10.19%	10.19%	10.19%	10.19%	10.19%	
(5) Return	$ 7,712,954	$ 249,036	$ 1,021,777	$ 838,368	$ 107,349	$ 1,463	$ 9,930,946
(6) Interest Expenses	$ 1,371,694	$ 44,289	$ 181,716	$ 149,098	$ 19,091	$ 260	$ 1,766,148
(7) Net Income	$ 6,341,260	$ 204,746	$ 840,061	$ 689,270	$ 88,258	$ 1,203	$ 8,164,798
(8) Income Taxes	$ 5,498,578	$ 177,538	$ 728,426	$ 597,674	$ 76,529	$ 1,043	$ 7,079,788
(9) Operation and Maintenance Expenses	$ 3,162,214	$ 24,108,891	$ 1,037,894	$ 917,217	$ 247,160	$ 122,016	$ 29,595,391
(10) Depreciation Expenses	$ 4,237,415	$ -	$ 365,916	$ 388,600	$ 48,826	$ -	$ 5,040,756
(11) Other Taxes	$ 505,141	$ (30)	$ 89,298	$ 66,756	$ 8,388	$ -	$ 669,552
(12) Curtailable Service Credit	$ 192,822						$ 192,822
(13) Expense Adjustments - Prod. Demand	$ (433,824)	$ -	$ -	$ -	$ -	$ -	$ (433,824)
(14) Expense Adjustments - Energy	$ -	$ (643,268)	$ -	$ -	$ -	$ -	$ (643,268)
(15) Expense Adjustments - Trans. Demand	$ -	$ -	$ (168,803)	$ -	$ -	$ -	$ (168,803)
(16) Expense Adjustments - Distribution	$ -	$ -	$ -	$ (82,706)	$ (10,590)	$ -	$ (93,296)
(17) Expense Adjustments - Other	$ (1,483,862)	$ (47,911)	$ (196,575)	$ (161,290)	$ (20,652)	$ (281)	$ (1,910,572)
(18) Expense Adjustments - Total	$ (1,917,686)	$ (691,179)	$ (365,378)	$ (243,996)	$ (31,242)	$ (281)	$ (3,249,763)
(19) Total Cost of Service	$ 19,391,438	$ 23,844,255	$ 2,877,932	$ 2,564,618	$ 457,008	$ 124,240	$ 49,259,491
(20) Less: Misc Revenue - Tran. Demand		$ -	$ (365,938)	$ -	$ -	$ -	$ (365,938)
(21) Less: Misc Revenue - Energy	$ -	$ (1,106,241)	$ -	$ -	$ -	$ -	$ (1,106,241)
(22) Less: Misc Revenue - Other	$ (143,099)	$ (4,620)	$ (18,957)	$ (15,554)	$ (1,992)	$ (27)	$ (184,249)
(23) Less: Misc Revenue - Total	$ (143,099)	$ (1,110,862)	$ (384,895)	$ (15,554)	$ (1,992)	$ (27)	$ (1,656,428)
(24) Net Cost of Service	$ 19,248,339	$ 22,733,393	$ 2,493,038	$ 2,549,064	$ 455,017	$ 124,213	$ 47,603,063
(25) Billing Units	1,379,179	723,169,766	1,379,179	1,379,179	3,576	3,576	
(26) Unit Costs	$ 13.96	$ 0.031436	$ 1.81	$ 1.85	$ 127.24	$ 34.74	$ 161.98

Customer Charge	$	161.98
Energy Charge	$	0.031436
Demand Charge	$	17.61
Distribution Customer	$	161.98
Distribution Customer Margin		16.51
	$	178.49

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31. 2012

Rate Time of Day Secondary

	Description	Production		Transmission	Distribution		Customer Service Expenses	Total
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	
(1)	Rate Base	$ 55,068,922	$ 1,688,016	$ 7,295,277	$ 7,304,496	$ 204,755	$ 35,200	$ 71,596,666
(2)	Rate Base Adjustments	(3,440,747)	(105,468)	(455,814)	(456,390)	(12,793)	(2,199)	$ (4,473,412)
(3)	Rate Base as Adjusted	$ 51,628,176	$ 1,582,547	$ 6,839,463	$ 6,848,106	$ 191,962	$ 33,001	$ 67,123,254
(4)	Rate of Return	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	
(5)	Return	$ 3,936,387	$ 120,661	$ 521,474	$ 522,133	$ 14,636	$ 2,516	$ 5,117,808
(6)	Interest Expenses	$ 936,939	$ 28,720	$ 124,121	$ 124,278	$ 3,484	$ 599	$ 1,218,140
(7)	Net Income	$ 2,999,448	$ 91,941	$ 397,353	$ 397,855	$ 11,152	$ 1,917	$ 3,899,668
(8)	Income Taxes	$ 1,004,945	$ 30,804	$ 133,131	$ 133,299	$ 3,737	$ 642	$ 1,306,558
(9)	Operation and Maintenance Expenses	$ 2,156,487	$ 15,608,524	$ 707,797	$ 660,850	$ 32,388	$ 281,417	$ 19,447,462
(10)	Depreciation Expenses	$ 2,889,725	$ -	$ 249,538	$ 323,694	$ 8,980	$ -	$ 3,471,937
(11)	Other Taxes	$ 344,483	$ (20)	$ 60,897	$ 55,606	$ 1,543	$ -	$ 462,509
(12)	Curtailable Service Credit	$ 123,238						$ 123,238
(13)	Expense Adjustments - Prod. Demand	$ (138,668)	$ -	$ -	$ -	$ -	$ -	$ (138,668)
(14)	Expense Adjustments - Energy	$ -	$ (387,237)	$ -	$ -	$ -	$ -	$ (387,237)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (115,116)	$ -	$ -	$ -	$ (115,116)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (67,215)	$ (1,884)	$ -	$ (69,099)
(17)	Expense Adjustments - Other	$ 790,690	$ 24,237	$ 104,747	$ 104,879	$ 2,940	$ 505	$ 1,027,999
(18)	Expense Adjustments - Total	$ 652,022	$ (363,000)	$ (10,369)	$ 37,664	$ 1,056	$ 505	$ 317,878
(19)	Total Cost of Service	$ 11,107,287	$ 15,396,970	$ 1,662,468	$ 1,733,247	$ 62,339	$ 285,081	$ 30,247,391
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (249,553)	$ -	$ -	$ -	$ (249,553)
(21)	Less: Misc Revenue - Energy	$ -	$ (719,948)	$ -	$ -	$ -	$ -	$ (719,948)
(22)	Less: Misc Revenue - Other	$ (94,994)	$ (2,912)	$ (12,584)	$ (12,600)	$ (353)	$ (61)	$ (123,504)
(23)	Less: Misc Revenue - Total	$ (94,994)	$ (722,860)	$ (262,137)	$ (12,600)	$ (353)	$ (61)	$ (1,093,005)
(24)	Net Cost of Service	$ 11,012,293	$ 14,674,110	$ 1,400,331	$ 1,720,646	$ 61,986	$ 285,020	$ 29,154,386
(25)	Billing Units	946,676	453,402,612	831,431	831,431	1,644	1,644	
(26)	Unit Costs	$ 11.63	$ 0.032364	$ 1.68	$ 2.07	$ 37.70	$ 173.37	$ 211.07

Customer Charge	$ 211.07
Energy Charge	$ 0.032364
Demand Charge	$ 15.39
Distribution Customer	$ 211.07
Distribution Customer Margin	16.09
	$ 227.17

Attachment to Response to KU PSC-3 Question No. 1
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Conroy

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate Time of Day Primary

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 397,868,413	$ 13,020,386	$ 52,707,776	$ 40,034,943	$ 794,537	$ 42,908	$ 504,468,963
(2)	Rate Base Adjustments	(25,445,711)	(832,720)	(3,370,931)	(2,560,438)	(50,815)	(2,744)	$ (32,263,359)
(3)	Rate Base as Adjusted	$ 372,422,702	$ 12,187,666	$ 49,336,846	$ 37,474,505	$ 743,723	$ 40,164	$ 472,205,604
(4)	Rate of Return	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	
(5)	Return	$ 28,211,275	$ 923,224	$ 3,737,300	$ 2,838,719	$ 56,337	$ 3,042	$ 35,769,899
(6)	Interest Expenses	$ 6,753,560	$ 221,013	$ 894,681	$ 679,567	$ 13,487	$ 728	$ 8,563,036
(7)	Net Income	$ 21,457,715	$ 702,211	$ 2,842,619	$ 2,159,152	$ 42,851	$ 2,314	$ 27,206,863
(8)	Income Taxes	$ 11,978,681	$ 392,007	$ 1,586,881	$ 1,205,338	$ 23,921	$ 1,292	$ 15,188,119
(9)	Operation and Maintenance Expenses	$ 15,580,437	$ 120,395,219	$ 5,113,774	$ 4,183,562	$ 176,713	$ 340,987	$ 145,790,692
(10)	Depreciation Expenses	$ 20,878,025	$ -	$ 1,802,891	$ 1,772,460	$ 34,496	$ -	$ 24,487,872
(11)	Other Taxes	$ 2,488,863	$ (151)	$ 439,977	$ 304,483	$ 5,926	$ -	$ 3,239,098
(12)	Curtailable Service Credit	$ 701,522						$ 701,522
(13)	Expense Adjustments - Prod. Demand	$ (1,036,325)	$ -	$ -	$ -	$ -	$ -	$ (1,036,325)
(14)	Expense Adjustments - Energy	$ -	$ (3,007,411)	$ -	$ -	$ -	$ -	$ (3,007,411)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (831,705)	$ -	$ -	$ -	$ (831,705)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (151,498)	$ (3,007)	$ -	$ (154,504)
(17)	Expense Adjustments - Other	$ 11,688	$ 382	$ 1,548	$ 1,176	$ 23	$ 1	$ 14,819
(18)	Expense Adjustments - Total	$ (1,024,638)	$ (3,007,028)	$ (830,157)	$ (150,322)	$ (2,983)	$ 1	$ (5,015,126)
(19)	Total Cost of Service	$ 78,814,166	$ 118,703,270	$ 11,850,666	$ 10,154,241	$ 294,410	$ 345,322	$ 220,162,076
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (1,802,999)	$ -	$ -	$ -	$ (1,802,999)
(21)	Less: Misc Revenue - Energy	$ -	$ (5,517,117)	$ -	$ -	$ -	$ -	$ (5,517,117)
(22)	Less: Misc Revenue - Other	$ (388,946)	$ (12,728)	$ (51,526)	$ (39,137)	$ (777)	$ (42)	$ (493,156)
(23)	Less: Misc Revenue - Total	$ (388,946)	$ (5,529,845)	$ (1,854,525)	$ (39,137)	$ (777)	$ (42)	$ (7,813,272)
(24)	Net Cost of Service	$ 78,425,220	$ 113,173,425	$ 9,996,141	$ 10,115,104	$ 293,634	$ 345,280	$ 212,348,804
(25)	Billing Units	5,142,035	3,611,372,403	5,142,035	5,142,035	2,004	2,004	
(26)	Unit Costs	$ 15.25	$ 0.03134	$ 1.94	$ 1.97	$ 146.52	$ 172.30	$ 318.82

Customer Charge	$	318.82
Energy Charge	$	0.03134
Demand Charge	$	19.16
Distribution Customer	$	318.82
Distribution Customer Margin		24.15
	$	342.97

Attachment to Response to KU PSC-3 Question No. 1
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Conroy

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate Retail Transmission Service

	Description	Production		Transmission	Distribution		Customer Service Expenses	Total
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	
(1)	Rate Base	$ 168,604,324	$ 5,433,025	$ 22,335,925	$ -	$ 993,346	$ 7,194	$ 197,373,814
(2)	Rate Base Adjustments	(11,643,067)	(375,181)	(1,542,420)	-	(68,596)	(497)	$ (13,629,760)
(3)	Rate Base as Adjusted	$ 156,961,257	$ 5,057,844	$ 20,793,505	$ -	$ 924,750	$ 6,697	$ 183,744,054
(4)	Rate of Return	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	
(5)	Return	$ 12,277,223	$ 395,615	$ 1,626,430	$ -	$ 72,332	$ 524	$ 14,372,125
(6)	Interest Expenses	$ 2,853,622	$ 91,954	$ 378,035	$ -	$ 16,812	$ 122	$ 3,340,544
(7)	Net Income	$ 9,423,602	$ 303,662	$ 1,248,395	$ -	$ 55,520	$ 402	$ 11,031,581
(8)	Income Taxes	$ 6,559,278	$ 211,363	$ 868,943	$ -	$ 38,645	$ 280	$ 7,678,508
(9)	Operation and Maintenance Expenses	$ 6,602,507	$ 50,237,389	$ 2,167,059	$ -	$ 230,531	$ 59,159	$ 59,296,646
(10)	Depreciation Expenses	$ 8,847,461	$ -	$ 764,009	$ -	$ 43,073	$ -	$ 9,654,543
(11)	Other Taxes	$ 1,054,703	$ (63)	$ 186,449	$ -	$ 7,399	$ -	$ 1,248,488
(12)	Curtailable Service Credit	$ 385,940						$ 385,940
(13)	Expense Adjustments - Prod. Demand	$ (436,180)	$ -	$ -	$ -	$ -	$ -	$ (436,180)
(14)	Expense Adjustments - Energy	$ -	$ (1,296,680)	$ -	$ -	$ -	$ -	$ (1,296,680)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (352,451)	$ -	$ -	$ -	$ (352,451)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(17)	Expense Adjustments - Other	$ (778,282)	$ (25,079)	$ (103,103)	$ -	$ (4,585)	$ (33)	$ (911,082)
(18)	Expense Adjustments - Total	$ (1,214,462)	$ (1,321,759)	$ (455,554)	$ -	$ (4,585)	$ (33)	$ (2,996,393)
(19)	Total Cost of Service	$ 34,512,651	$ 49,522,546	$ 5,157,337	$ -	$ 387,394	$ 59,930	$ 89,639,857
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (764,055)	$ -	$ -	$ -	$ (764,055)
(21)	Less: Misc Revenue - Energy	$ -	$ (2,305,605)	$ -	$ -	$ -	$ -	$ (2,305,605)
(22)	Less: Misc Revenue - Other	$ (138,563)	$ (4,465)	$ (18,356)	$ -	$ (816)	$ (6)	$ (162,207)
(23)	Less: Misc Revenue - Total	$ (138,563)	$ (2,310,070)	$ (782,412)	$ -	$ (816)	$ (6)	$ (3,231,867)
(24)	Net Cost of Service	$ 34,374,087	$ 47,212,476	$ 4,374,925	$ -	$ 386,578	$ 59,924	$ 86,407,990
(25)	Billing Units	3,454,547	1,548,306,282	3,454,547	3,454,547	420	420	
(26)	Unit Costs	$ 9.95	$ 0.03049	$ 1.27	$ -	$ 920.42	$ 142.68	$ 1,063.10

Customer Charge	$	1,063.10
Energy Charge	$	0.03049
Demand Charge	$	11.22
Distribution Customer	$	1,063.10
Distribution Customer Margin		83.15
	$	1,146.25

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate Fluctuating Load Service

	Description	Production Demand-Related	Production Energy-Related	Transmission Demand-Related	Distribution Demand-Related	Distribution Customer-Related	Customer Service Expenses Customer-Related	Total
(1)	Rate Base	$ 49,946,237	$ 1,764,581	$ 6,616,648	$ -	$ 36,495	$ 514	$ 58,364,475
(2)	Rate Base Adjustments	(3,453,736)	(122,019)	(457,535)	-	(2,524)	(36)	$ (4,035,849)
(3)	Rate Base as Adjusted	$ 46,492,501	$ 1,642,562	$ 6,159,113	$ -	$ 33,972	$ 478	$ 54,328,626
(4)	Rate of Return	6.13%	6.13%	6.13%	6.13%	6.13%	6.13%	
(5)	Return	$ 2,852,064	$ 100,762	$ 377,828	$ -	$ 2,084	$ 29	$ 3,332,768
(6)	Interest Expenses	$ 843,033	$ 29,784	$ 111,681	$ -	$ 616	$ 9	$ 985,123
(7)	Net Income	$ 2,009,030	$ 70,978	$ 266,147	$ -	$ 1,468	$ 21	$ 2,347,644
(8)	Income Taxes	$ 1,397,709	$ 49,381	$ 185,162	$ -	$ 1,021	$ 14	$ 1,633,287
(9)	Operation and Maintenance Expenses	$ 1,955,883	$ 16,316,499	$ 641,955	$ -	$ 8,470	$ 4,108	$ 18,926,916
(10)	Depreciation Expenses	$ 2,620,914	$ -	$ 226,325	$ -	$ 1,582	$ -	$ 2,848,821
(11)	Other Taxes	$ 312,438	$ (20)	$ 55,232	$ -	$ 272	$ -	$ 367,922
(12)	Curtailable Service Credit	$ (5,304,395)						$ (5,304,395)
(13)	Expense Adjustments - Prod. Demand	$ (107,761)	$ -	$ -	$ -	$ -	$ -	$ (107,761)
(14)	Expense Adjustments - Energy	$ -	$ (422,188)	$ -	$ -	$ -	$ -	$ (422,188)
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (104,408)	$ -	$ -	$ -	$ (104,408)
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(17)	Expense Adjustments - Other	$ (294,651)	$ (10,410)	$ (39,034)	$ -	$ (215)	$ (3)	$ (344,313)
(18)	Expense Adjustments - Total	$ (402,411)	$ (432,598)	$ (143,442)	$ -	$ (215)	$ (3)	$ (978,669)
(19)	Total Cost of Service	$ 3,432,202	$ 16,034,024	$ 1,343,062	$ -	$ 13,214	$ 4,149	$ 20,826,650
(20)	Less: Misc Revenue - Tran. Demand		$ -	$ (226,339)	$ -	$ -	$ -	$ (226,339)
(21)	Less: Misc Revenue - Energy	$ -	$ (742,363)	$ -	$ -	$ -	$ -	$ (742,363)
(22)	Less: Misc Revenue - Other	$ (31,059)	$ (1,097)	$ (4,115)	$ -	$ (23)	$ (0)	$ (36,294)
(23)	Less: Misc Revenue - Total	$ (31,059)	$ (743,461)	$ (230,453)	$ -	$ (23)	$ (0)	$ (1,004,996)
(24)	Net Cost of Service	$ 3,401,143	$ 15,290,563	$ 1,112,608	$ -	$ 13,191	$ 4,149	$ 19,821,654
(25)	Billing Units	2,169,914	502,871,246	2,169,914	2,169,914	12	12	
(26)	Unit Costs	$ 1.57	$ 0.03041	$ 0.51	$ -	$ 1,099.27	$ 345.72	$ 1,444.99

Customer Charge	$	1,444.99
Energy Charge	$	0.03041
Demand Charge	$	2.08
Distribution Customer	$	1,444.99
Distribution Customer Margin		88.64
	$	1,533.63

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 2

Responding Witness: Robert M. Conroy

Q-2. Refer to Conroy Testimony, Conroy Exhibit M2. Pages 1 and 2 state that the source of the referenced costs is Exhibit Conroy C4. Provide the location in Exhibit Conroy C4 of each of the costs shown on these pages.

A-2. In preparing this response, KU determined that Conroy Exhibit M2 as originally filed had not been updated to reflect the final cost of service results. KU provided an electronic version of Conroy Exhibit M2 in "Att-PSC2-75-File10" ('M-2 KU Redundant Capacity.xlsx'). KU is providing in Excel format an updated spreadsheet ('M-2 KU Redundant Capacity Revised.xlsx'). See Attachment 1 for a revised Conroy Exhibit M2.

All amounts on Conroy Exhibit M2 that are referenced to Conroy Exhibit C4 are either taken directly from Conroy Exhibit C4, or are the result of mathematical operations using amounts directly from Conroy Exhibit C4. See Attachment 2 for a line–by–line link between the amounts on revised Conroy Exhibit M2 and Conroy Exhibit C4.

One attachment is being provided in a separate file in Excel format.

Kentucky Utilities
Redundant Capacity Charge Cost Support
Distribution Demand-Related Cost
Twelve Months Ended March 31, 2012

Revisions Highlighted

Secondary Service

Distribution Demand Costs			
PSS	$ 9,030,787		
TODS	$ 1,198,513		
Total Cost	$ 10,229,300		
Billing Demand			
PSS	8,750,756		
TODS	831,431		
Total Cost	9,582,187		
Unit Cost		$ 1.07	
Rate Base			
PSS	$ 46,066,305		
TODS	$ 6,848,106		
Total Cost	$ 52,914,411		
Return	$ 4,016,204		
Unit Return		$ 0.42	
Capacity Charge		$ 1.49	/ KW

Source: Electric Cost of Service Study, Conroy Exhibit C4

Kentucky Utilities
Redundant Capacity Charge Cost Support
Distribution Demand-Related Cost
Twelve Months Ended March 31, 2012

Revisions Highlighted

Primary Service

Distribution Demand Costs					
PSP	$	1,710,697			
TODP	$	7,276,384			
Total Cost	$	8,987,081			
Billing Demand					
PSP		1,830,921			
TODP		8,110,339			
Total Cost		9,941,260			
Unit Cost			$	0.90	
Rate Base					
PSP	$	8,223,912			
TODP	$	37,474,505			
Total Cost	$	45,698,417			
Return	$	3,468,510			
Unit Return			$	0.35	
Capacity Charge			$	1.25	/ KW

Source: Electric Cost of Service Study, Conroy Exhibit C4

KU Exhibit M2,page 2 of 4, Tied to Cost of Service C4 — Primary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2 Revised
Blue highlighted cells are inputs from Conroy Exhibit C4 Revised
all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
		Distribution Primary	Rate PS-P	Rate TODP	
1	Distribution Demand Costs -- Conroy Exhibit M2	$ 8,987,081	$ 1,710,697	$ 7,276,384	Sum of Ls.3 through 10
2	Net Income	$ 2,848,422	$ 689,270	$ 2,159,152	L.54 - L.58
3	Income Taxes	$ 1,803,012	$ 597,674	$ 1,205,338	L.17
4	Operation and Maintenance Expenses	5,100,779	917,217	4,183,562	C4, page 7-8, Distribution Substation general, Lines primary demand
5	Depreciation Expenses	2,161,060	388,600	1,772,460	C4, page 11-12, Distribution Substation general, Lines primary demand
6	Other Expenses	371,239	66,756	304,483	Sum of individual components 6a through 6c
a	Regulatory Credits & Accretion	(750)	(135)	(615)	C4, page 13-14, Distribution Substation general, Lines primary demand
b	Property Taxes	244,673	43,997	200,676	C4, page 15-16, Distribution Substation general, Lines primary demand
c	Other Taxes	127,316	22,894	104,422	C4, page 17-18, Distribution Substation general, Lines primary demand
7	Curtailable Service Credit	-	-	-	Assigned 100% to production
8	Expense Adjustments - Distribution	(234,204)	(82,706)	(151,498)	L.37
9	Expense Adjustments	(160,114)	(161,290)	1,176	L.36
10	Miscellaneous Revenue - Other (enter as negative)	$ (54,692)	$ (15,554)	$ (39,137)	L.49 ÷ L.39 x L.68
11	Total net income for rate schedule		$ 9,930,946	$ 35,769,899	C4, p. 33-34, Net Operating Income, Pro-Forma
12	Less interest expense		$ 1,766,148	$ 8,563,036	L.57
13	Net income less interest		$ 8,164,798	$ 27,206,863	L.11 - L.12
	Income taxes allocated to demand based on net income:				
14	Income taxes -- actual		$ 6,134,474	$ 10,571,115	C4, p.29-30, Sate and Federal Income Taxes
15	Incremental income taxes		$ 945,315	$ 4,617,004	C4, p. 33-34, Incremental income taxes
16	Total Income Taxes		$ 7,079,789	$ 15,188,119	L.14 + L.15
17	Distribution Demand component of income taxes		$ 597,674	$ 1,205,338	L.13 ÷ L.2 x L.16

Expense Adjustments from Unit Cost schedules

		Total Primary	Rate PS-P	Rate TOD-P	
18	Expense Adjustments assigned to Distribution				
19	Eliminate DSM Expenses (allocate to demand & customer)	$ (207,004)	$ (85,849)	$ (121,155)	C4, page 29-30 PS-P and TOD-P
20	Normalized storm damage expenses (allocate to demand & customer)	(40,796)	(7,447)	(33,349)	C4, page 29-30 PS-P and TOD-P
21	Year end adjustment	$ (921,229)	$ 96,242	$ (1,017,471)	C4, page 29-30 PS-P and TOD-P
22	Annualized depreciation expenses under current rates	125,518	21,427	104,091	C4, page 29-30 PS-P and TOD-P
23	Labor adjustment	426,986	73,242	353,744	C4, page 29-30 PS-P and TOD-P
24	Pension & post retirement expense adjustment	(602,376)	(103,327)	(499,049)	C4, page 29-30 PS-P and TOD-P
25	Property insurance expense adjustment	187,887	32,102	155,785	C4, page 29-30 PS-P and TOD-P
26	Remove out of period items	(82,704)	(14,133)	(68,571)	C4, page 29-30 PS-P and TOD-P
27	Eliminate advertising expenses	(158,869)	(32,200)	(126,669)	C4, page 29-30 PS-P and TOD-P
28	Amortization of rate case expenses	(5,169)	(872)	(4,297)	C4, page 29-30 PS-P and TOD-P
29	Adjustment for injuries and damages FERC account 925	(214,698)	(36,683)	(178,015)	C4, page 29-30 PS-P and TOD-P
30	General Management Audit regulatory asset amortization	9,702	1,637	8,065	C4, page 29-30 PS-P and TOD-P
31	Federal & State Income Tax Adjustment	(544,875)	(1,905,438)	1,360,563	C4, page 29-30 PS-P and TOD-P
32	Federal & State Income Tax Interest Adjustment	27,058	9,936	17,122	C4, page 29-30 PS-P and TOD-P
33	Adjustment for tax basis depreciation reduction	(61,703)	(22,658)	(39,045)	C4, page 29-30 PS-P and TOD-P
34	Prior income tax true-ups & adjustments	(81,280)	(29,847)	(51,433)	C4, page 29-30 PS-P and TOD-P
35	Total of Other Expense Adjustments	$ (2,143,552)	$ (1,910,572)	$ 14,820	Sum of Ls.21 - 34

KU Exhibit M2,page 2 of 4, Tied to Cost of Service C4 — Primary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2 Revised
Blue highlighted cells are inputs from Conroy Exhibit C4 Revised
all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C) Distribution Primary	Rate PS-P	Rate TODP	
36	Total Primary portion of other expense adj	$ (160,114)	$ (161,290)	$ 1,176	L.49 ÷ L.39 x L.35
37	Total Primary portion of distribution exp adj	$ (234,204)	$ (82,706)	$ (151,498)	(L.19 + L.20) x (L.49÷ (L.49 + L.50))
38	Total Primary expense adjustments	$ (394,318)	$ (243,996)	$ (150,322)	Sum of Ls.36 - 37
		Total System Rate Base, C4 page 5	Rate PS-P	Rate TODP	
39	Rate Base	$ 3,500,935,146	$ 103,973,077	$ 504,468,963	C4, page 29-30 PS-P and TOD-P
40	Rate Base Adjustments:	C4, page 29 Total System			
41	ECR Plan Eliminations	(183,667,066)	(6,407,840)	(31,571,854)	C4, page 29-30 PS-P and TOD-P
42	Adjustmentto Reflect Depreciation Reserve	(712,846)	(21,427)	(104,091)	C4, page 29-30 PS-P and TOD-P
43	Cash Working Capital	(5,709,964)	(126,906)	(587,414)	C4, page 29-30 PS-P and TOD-P
44	Total Rate Base Adjustments	(190,089,876)	(6,556,173)	(32,263,359)	Sum of Ls.41 - 43
45	Adjusted Net Rate Base	$ 3,310,845,270	$ 97,416,904	$ 472,205,604	L.39 + L.44
46	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:		Rate PS-P	Rate TODP	
47	Substation Demand Rate Base		$ 3,350,639	$ 15,282,762	C4, p 5-6, PS-P and TOD-P Distribution Substation
48	Primary Lines Demand Rate Base		5,426,744	24,752,182	C4, p 5-6, PS-P and TOD-P Distribution Lines
49	Total Primary Demand Rate Base		$ 8,777,383	$ 40,034,944	Sum of Ls.47 - 48
50	Primary Customer Rate Base		1,123,899	794,537	C4, p 5-5 PS-P and TOD-P, Primary Customer Lines and Meters
51	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base		(553,471)	(2,560,439)	L.49 ÷ L.39 x L.44
52	Primary Demand Only Adjusted Rate Base, Exhibit M2		$ 8,223,912	$ 37,474,505	L.49 + L.51
53	Cost of Service Proposed Rate of Return		10.19%	7.58%	C4, p33-34 Rate of Return
54	Primary Demand Return on Rate Base		$ 838,368	$ 2,838,720	L.52 x L.53
	Allocate Interest Expense based on unadjdusted rate base:				
55	Rate Base		$ 103,973,077	$ 504,468,963	L. 39 above
56	Primary Demand only Rate Base		$ 8,777,383	$ 40,034,944	L. 49 above
57	Interest Expense		$ 1,766,148	$ 8,563,036	C4, p31-32, Interest Expense
58	Interest Expense allocated to distribution demand		$ 149,098	$ 679,567	L.56 ÷ L.55 x L.57
	Allocate Miscellaneous Revenue based on rate base				
59	Late payment charges		$ 29,221	$ 179,921	C4, pp 23-24, PS-P and TOD-P
60	Reconnect charges		63,194	99	C4, pp 23-24, PS-P and TOD-P
61	Other service charges		20,830	32	C4, pp 23-24, PS-P and TOD-P
62	Rent from electric property		64,082	310,977	C4, pp 23-24, PS-P and TOD-P
63	Tax remittanced compensation		682	2,681	C4, pp 23-24, PS-P and TOD-P
64	Return check charges		4,983	8	C4, pp 23-24, PS-P and TOD-P
65	Other miscellaneous revenues		858	1	C4, pp 23-24, PS-P and TOD-P
66	Excess facilities charges		544	1	C4, pp 23-24, PS-P and TOD-P
67	Forfeited refundable advances		(143)	(564)	C4, pp 23-24, PS-P and TOD-P
68	Total miscellaneous revenue to allocate		$ 184,251	$ 493,156	Sum of Ls.59 through 67

KU Exhibit M2,page 2 of 2, Tied to Cost of Service C4 — Secondary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2 Revised
Blue highlighted cells are inputs from Conroy Exhibit C4 Revised
all other cells are calculated

		A	B	C	
		(A) = (B) + (C)			
	Conroy Exhibit M2, Page 1	Distribution Secondary	Rate PS-S	Rate TOD-S	
1	Distribution Demand Costs -- Conroy Exhibit M2	$ 10,229,300	$ 9,030,787	$ 1,198,513	Sum of Ls.3 through 10
2	Net Income	$ 4,695,179	$ 4,297,324	$ 397,855	L.56 - L.60
3	Income Taxes	$ 2,869,450	$ 2,736,151	$ 133,299	L.17
4	Operation and Maintenance Expenses	5,111,654	4,450,804	660,850	C4, page 7-8, Distribution Substation general, Lines pri & sec demand, line transformers demand
5	Depreciation Expenses	2,498,530	2,174,836	323,694	C4, page 11-12, Distribution Substation general, Lines pri & sec demand, line transformers demand
6	Other Taxes	429,211	373,605	55,606	Sum of individual components 6a through 6c
a	Regulatory Credits & Accretion	(866)	(754)	(112)	C4, page 13-14, Distribution Substation general, Lines pri & sec demand, line transformers demand
b	Property Taxes	282,881	246,233	36,648	C4, page 15-16, Distribution Substation general, Lines pri & sec demand, line transformers demand
c	Other Taxes	147,197	128,127	19,070	C4, page 17-18, Distribution Substation general, Lines pri & sec demand, line transformers demand
7	Curtailable Service Credit	-	-	-	Assigned 100% to production
8	Expense Adjustments - Distribution	(520,067)	(452,852)	(67,215)	L.37
9	Expense Adjustments	(92,219)	(197,098)	104,879	L.36
10	Miscellaneous Revenue - Other (enter as negative)	$ (67,259)	$ (54,659)	$ (12,600)	L.51 ÷ L.39 x L.67
11	Total net income for rate schedule		$ 48,801,326	$ 5,117,808	C4, p. 33-34, Net Operating Income, Pro-Forma
12	Less interest expense		$ 7,934,198	$ 1,218,140	L.59
13	Net income less interest		$ 40,867,128	$ 3,899,668	L.11 - L.12
	Income taxes allocated to demand based on net income:				
14	Income taxes -- actual		$ 24,409,874	$ 605,177	C4, p.29-30, Sate and Federal Income Taxes
15	Incremental income taxes		$ 1,610,652	$ 701,381	C4, p. 33-34, Incremental income taxes
16	Total Income Taxes		$ 26,020,526	$ 1,306,558	L.14 + L.15
17	Distribution Demand component of income taxes		$ 2,736,151	$ 133,298.78	L.13 ÷ L.2 x L.16
			Expense Adjustments from Unit Cost schedules		
		Total Secondary	Rate PS	Rate TODP	
18	Expense Adjustments assigned to Distribution				
19	Eliminate DSM Expenses (allocate to demand & customer)	$ (526,891)	$ (465,083)	$ (61,808)	C4, page 29-30 PS-S and TOD-S
20	Normalized storm damage expenses (allocate to demand & customer)	(61,204)	(53,913)	(7,291)	C4, page 29-30 PS-S and TOD-S
21	Year end adjustment	(810,203)	(875,402)	65,199	C4, page 29-30 PS-S and TOD-S
22	Annualized depreciation expenses under current rates	110,673	95,915	14,758	C4, page 29-30 PS-S and TOD-S
23	Labor adjustment	397,588	346,213	51,375	C4, page 29-30 PS-S and TOD-S
24	Pension & post retirement expense adjustment	(560,903)	(488,424)	(72,479)	C4, page 29-30 PS-S and TOD-S
25	Property insurance expense adjustment	166,105	143,978	22,127	C4, page 29-30 PS-S and TOD-S
26	Remove out of period items	(73,173)	(63,441)	(9,732)	C4, page 29-30 PS-S and TOD-S
27	Eliminate advertising expenses	(154,835)	(139,063)	(15,772)	C4, page 29-30 PS-S and TOD-S
28	Amortization of rate case expenses	(4,449)	(3,876)	(573)	C4, page 29-30 PS-S and TOD-S
29	Adjustment for injuries and damages FERC account 925	(189,808)	(164,523)	(25,285)	C4, page 29-30 PS-S and TOD-S
30	General Management Audit regulatory asset amortization	8,351	7,275	1,076	C4, page 29-30 PS-S and TOD-S
31	Federal & State Income Tax Adjustment	437,853	(563,650)	1,001,503	C4, page 29-30 PS-S and TOD-S
32	Federal & State Income Tax Interest Adjustment	40,516	39,536	980	C4, page 29-30 PS-S and TOD-S
33	Adjustment for tax basis depreciation reduction	(92,393)	(90,158)	(2,235)	C4, page 29-30 PS-S and TOD-S
34	Prior income tax true-ups & adjustments	(121,708)	(118,764)	(2,944)	C4, page 29-30 PS-S and TOD-S
35	Total of Other Expense Adjustments	$ (1,434,481)	$ (1,874,384)	$ 1,027,998	Sum of Ls.21 - 34

KU Exhibit M2,page 2 of 2, Tied to Cost of Service C4 — Secondary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2 Revised
Blue highlighted cells are inputs from Conroy Exhibit C4 Revised
all other cells are calculated

		A	B	C	
		(A) = (B) + (C)			
	Conroy Exhibit M2, Page 1	Distribution Secondary	Rate PS-S	Rate TOD-S	
36	Total Secondary demand portion of other expense adj	$ (92,219)	$ (197,098)	$ 104,879	L.51 ÷ L.39 x L.35
37	Total Secondary demand portion of distribution exp adj	$ (520,067)	$ (452,852)	$ (67,215)	(L.19 + L.20) x (L.51÷ (L.51 + L.52))
38	Total Secondary expense adjustments	$ (612,286)	$ (649,950)	$ 37,664	Sum of Ls.36 - 37
		Total System Rate Base, C4 page 5	Rate PS-S	Rate TOD-S	
39	Rate Base	$ 3,500,935,146	$ 466,728,220	$ 71,596,666	C-4, page 29-30 PS-S and TOD-S
40	Rate Base Adjustments:	C4, page 29 Total System			
41	ECR Plan Eliminations	(183,667,066)	(27,943,177)	(4,369,857)	C-4, page 29-30 PS-S and TOD-S
42	Adjustmentto Reflect Depreciation Reserve	(712,846)	(95,915)	(14,758)	C-4, page 29-30 PS-S and TOD-S
43	Cash Working Capital	(5,709,964)	(603,079)	(88,797)	C-4, page 29-30 PS-S and TOD-S
44	Total Rate Base Adjustments	(190,089,876)	(28,642,171)	(4,473,412)	Sum of Ls.41 - 43
45	Adjusted Net Rate Base	$ 3,310,845,270	$ 438,086,049	$ 67,123,254	L.39 + L.44
46	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:		Rate PS-S	Rate TOD-S	
47	Substation Demand Rate Base		$ 13,435,476	$ 1,987,292	C-4, pp 5&6, PS-S and TOD-S Distribution Substation
48	Primary Lines Demand Rate Base		21,760,290	3,218,647	C-4, pp 5&6, PS-S and TOD-S Distribution Primary Lines
49	Secondary Lines Demand Rate Base		3,081,519	465,824	C-4, pp 5&6, PS-S and TOD-S Distribution Secondary
50	Distribution Lines Transformers Rate Base		10,800,846	1,632,733	C-4, pp 5&6, PS-S and TOD-S Distribution Line Transformers
51	Total Secondary Demand Rate Base		$ 49,078,131	$ 7,304,496	Sum of Ls.49 - 50
52	Secondary Customer Rate Base		7,168,404	204,755	C4, p 5-6 PS-S and TOD-S, Primary Customer Lines, Transformers and Meters
53	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base		(3,011,826)	(456,390.25)	L.51 ÷ L.39 x L.44
54	Secondary Demand Only Adjusted Rate Base, Exhibit M2		$ 46,066,305	$ 6,848,106	L.51 + L.53
55	Cost of Service Proposed Rate of Return		11.14%	7.62%	C4, p33-34 Rate of Return
56	Secondary Demand Return on Rate Base		$ 5,131,633	$ 522,133	L.54 x L.55
	Allocate Interest Expense based on unadjdusted rate base:				
57	Rate Base		$ 466,728,220	$ 71,596,666	L. 41 above
58	Secondary Demand only Rate Base		$ 49,078,131	$ 7,304,496	L. 51 above
59	Interest Expense		$ 7,934,198	$ 1,218,140	C4, p31-32, Interest Expense
60	Interest Expense allocated to distribution demand		$ 834,309	$ 124,278	L.58 ÷ L.57 x L.59
	Allocate Miscellaneous Revenue based on rate base				
61	Late payment charges		$ 225,327	$ 75,334	C4, pp 23-24, PS-S and TOD-S
62	Reconnect charges		3,314	2,611	C4, pp 23-24, PS-S and TOD-S
63	Other service charges		1,092	861	C4, pp 23-24, PS-S and TOD-S
64	Rent from electric property		287,408	44,170	C4, pp 23-24, PS-S and TOD-S
65	Tax remittanced compensation		2,944	334	C4, pp 23-24, PS-S and TOD-S
66	Return check charges		261	206	C4, pp 23-24, PS-S and TOD-S
67	Other miscellaneous revenues		45	35	C4, pp 23-24, PS-S and TOD-S
68	Excess facilities charges		29	22	C4, pp 23-24, PS-S and TOD-S
69	Forfeited refundable advances		(620)	(70)	C4, pp 23-24, PS-S and TOD-S
70	Total miscellaneous revenue to allocate		$ 519,800	$ 123,504	Sum of Ls.61 through 69

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 3

Responding Witness: Robert M. Conroy

Q-3. Refer to Conroy Testimony, Conroy Exhibit M3, pages 1-3. For the amounts referenced to Exhibit Conroy C4, provide their location in that exhibit.

A-3. The revisions made to the cost of service study referenced in response to Question No. 1 resulted in changes to Conroy Exhibit M3 as originally filed. KU provided an electronic version of Conroy Exhibit M3 in "Att-PSC2-75-File10" ('M-3 KU Standby Rate Final.xlsx'). KU is providing in Excel format an updated spreadsheet ('M-3 Standby Rate Revised.xlsx'). See Attachment 1 for a revised Conroy Exhibit M3.

All amounts on Conroy Exhibit M3 that are referenced to Conroy Exhibit C4 are either taken directly from Conroy Exhibit C4, or are the result of mathematical operations using amounts directly from Conroy Exhibit C4. See Attachment 2 for a line–by–line link between the amounts on revised Conroy Exhibit M3 and Conroy Exhibit C4.

One attachment is being provided in a separate file in Excel format.

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Production and Transmission Unit Demand Costs
Total System

	Reference	Total Production Cost	Total Transmission Cost	Total
Operation and Maintenance Expenses	Conroy Exhibit C4	$ 90,638,112	$ 29,749,027	$ 120,387,139
Depreciation Expenses	Conroy Exhibit C4	121,456,460	10,488,193	$ 131,944,653
Accretion Expenses	Conroy Exhibit C4	(2,647,544)	(5,404)	$ (2,652,948)
Property Taxes	Conroy Exhibit C4	11,264,737	1,687,073	$ 12,951,810
Other Taxes	Conroy Exhibit C4	5,861,594	877,867	$ 6,739,461
Gain Disposition of Allowances and other	Conroy Exhibit C4	-	-	$ -
Expense Adjustments	Conroy Exhibit C4	(13,835,798)	(5,438,023)	$ (19,273,821)
Sub-Total Expenses		$ 212,737,561	$ 37,358,733	$ 250,096,294
Adjusted Rate Base	Conroy Exhibit C4	2,188,897,801	289,975,107	2,478,872,908
Return	Rate Base x Weighted Cost of Capital %	166,694,855	22,082,967	188,777,823
Income Taxes	Rate Base x Income Tax %	75,117,102	9,951,168	85,068,270
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 454,549,518	$ 69,392,868	$ 523,942,386
100% Load Factor Demand	System CP x 12 months @ 90% PF	46,888,627	46,888,627	46,888,627
Unit Cost (Single Phase)	Total Revenue Requirement / Demand	$ 9.69	$ 1.48	$ 11.17

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%		1.71%
Common Equity	53.70%	11.00%	5.91%	3.43%	9.34%
Total Capitalization	100.00%		7.62%		11.05%
Composite State and Fed Inc Tax Rate	36.7473%				

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Primary Distribution Unit Demand Costs
Power Service Primary & TOD Primary

Revisions Highlighted

	Reference	**Distribution Primary Substation Cost**	**Distribution Primary Lines Cost**	**Distribution Primary Transformer Cost**	**Total**
Operation and Maintenance Expenses	Conroy Exhibit C4	$ 1,282,565	$ 3,818,214	$ -	$ 5,100,779
Depreciation Expenses	Conroy Exhibit C4	$ 824,947	$ 1,336,113	$ -	$ 2,161,060
Accretion Expenses	Conroy Exhibit C4	$ (286)	$ (464)	$ -	$ (750)
Property Taxes	Conroy Exhibit C4	$ 93,400	$ 151,273	$ -	$ 244,673
Other Taxes	Conroy Exhibit C4	$ 48,600	$ 78,715	$ -	$ 127,315
Gain Disposition of Allowances and other	Conroy Exhibit C4	$ -	$ -	$ -	$ -
Expense Adjustments	Conroy Exhibit C4	$ (99,149)	$ (295,169)	$ -	$ (394,318)
Sub-Total Expenses		$ 2,150,076	$ 5,088,683	$ -	$ 7,238,759
Adjusted Rate Base	Conroy Exhibit C4	17,444,711	28,253,706	-	45,698,417
Return	Rate Base x Weighted Cost of Capital %	1,328,497	2,151,653	-	3,480,149
Income Taxes	Rate Base x Income Tax %	598,656	969,591	-	1,568,247
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 4,077,228	$ 8,209,927	$ -	$ 12,287,156
Billing Demand	Billing Demand @ 90% PF	10,389,465	10,389,465	10,389,465	10,389,465
Unit Cost (Single Phase)	Total Revenue Requirement / Demand	$ 0.3924	$ 0.7902	$ -	$ 1.1827

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%		1.71%
Common Equity	53.70%	11.00%	5.91%	3.43%	9.34%
Total Capitalization	100.00%		7.62%		11.05%
Composite State and Fed Inc Tax Rate	36.7473%				

Attachment 1 to Response to KU PSC-3 Question No. 3
Revised Conroy Exhibit M3

Conroy

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Secondary Distribution Unit Demand Costs
Power Service Secondary & TOD Secondary

Revisions Highlighted

	Reference	**Distribution Secondary Substation Cost**	**Distribution Secondary Lines Cost**	**Distribution Secondary Transformer Cost**	**Total**
Operation and Maintenance Expenses	Conroy Exhibit C4	$ 1,061,572	$ 448,807	$ 440,959	$ 1,951,338
Depreciation Expenses	Conroy Exhibit C4	$ 682,804	$ 157,052	$ 552,781	$ 1,392,637
Accretion Expenses	Conroy Exhibit C4	$ (237)	$ (54)	$ (192)	$ (483)
Property Taxes	Conroy Exhibit C4	$ 77,306	$ 17,781	$ 62,585	$ 157,673
Other Taxes	Conroy Exhibit C4	$ 40,226	$ 9,252	$ 32,566	$ 82,045
Gain Disposition of Allowances and other	Conroy Exhibit C4	$ -	$ -	$ -	$ -
Expense Adjustments	Conroy Exhibit C4	$ (333,731)	$ (140,506)	$ (138,049)	$ (612,286)
Sub-Total Expenses		$ 1,527,941	$ 492,332	$ 950,650	$ 2,970,924
Adjusted Rate Base	Conroy Exhibit C4	13,719,509	3,155,569	11,060,396	27,935,474
Return	Rate Base x Weighted Cost of Capital %	1,044,805	240,311	842,301	2,127,418
Income Taxes	Rate Base x Income Tax %	470,817	108,291	379,563	958,671
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 3,043,563	$ 840,934	$ 2,172,515	$ 6,057,012
Billing Demand	Billing Demand @ 90% PF	10,758,050	10,758,050	10,758,050	10,758,050
Unit Cost (Single Phase)	Total Revenue Requirement / Demand	$ 0.2829	$ 0.0782	$ 0.2019	$ 0.5630

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%		1.71%
Common Equity	53.70%	11.00%	5.91%	3.43%	9.34%
Total Capitalization	100.00%		7.62%		11.05%
Composite State and Fed Inc Tax Rate	36.7473%				

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Calculation of KU 100% Load Factor Demand

KU System Peak	(1) * 12
(1)	(2)
3,516,647	42,199,764

)% Power Factor Adjustme	(2) / (3)
(3)	(4)
90%	46,888,627

00% Load Factor Deman
46,888,627

KU Exhibit M-3, page 1, tied to Cost of Service C-4

Production and Transmission Unit Demand Costs

Note: Purple cells tie to Conroy Exhibit M3 Revised
Blue Cells tie to Conroy Exhibit C4 Revised
All other cells calculated

	Conroy M-3, Page 1	Total Production Cost	
1	Operation and Maintenance Expenses	$ 90,638,112	C-4, page 7, Total System Production Demand Base, Intermediate, Peak
2	Depreciation Expenses	121,456,460	C-4, page 11, Total System Production Demand Base, Intermediate, Peak
3	Accretion Expenses	(2,647,544)	C-4, page 13, Total System Production Demand Base, Intermediate, Peak
4	Property Taxes	11,264,737	C-4, page 15, Total System Production Demand Base, Intermediate, Peak
5	Other Taxes	5,861,594	C-4, page 17, Total System Production Demand Base, Intermediate, Peak
6	Expense Adjustments	(13,835,798)	L. 34, Production Demand
7	Subtotal Production Expenses	$ 212,737,561	Sum of Ls. 1 - 6
8	Adjusted Rate Base	$ 2,188,897,801	Line 39, Production Rate Base

	Conroy M-3, Page 1	Total Transmission Cost	
9	Operation and Maintenance Expenses	$ 29,749,027	C-4, page 7, Total System Transmission Demand Base, Intermediate, Peak
10	Depreciation Expenses	10,488,193	C-4, page 11, Total System Transmission Demand Base, Intermediate, Peak
11	Accretion Expenses	(5,404)	C-4, page 13, Total System Transmission Demand Base, Intermediate, Peak
12	Property Taxes	1,687,073	C-4, page 15, Total System Transmission Demand Base, Intermediate, Peak
13	Other Taxes	877,867	C-4, page 17, Total System Transmission Demand Base, Intermediate, Peak
14	Expense Adjustments	(5,438,023)	L. 34, Transmisison Expense Adjustments
15	Subtotal Transmission Expenses	$ 37,358,733	Sum of Ls. 9 - 14
16	Adjusted Rate Base	$ 289,975,107	L. 39, Transmission Rate Base

KU Exhibit M-3, page 1, tied to Cost of Service C-4

Production and Transmission Unit Demand Costs

Note: Purple cells tie to Conroy Exhibit M3 Revised
Blue Cells tie to Conroy Exhibit C4 Revised
All other cells calculated

		C-4, page 29 total system	Expense Adjustments Production	Transmission	
	Expense Adjustments assigned to Production Demand:				
17	Remove ECR Expenses	$ (9,309,387)	$ (9,309,387)	$ -	ECR direct assigned to production
	Expense Adjustments assigned to Transmission Demand				
18	Adjustment for transfer of ITO functions	(3,328,434)	-	(3,328,434)	ITO costs direct assigned to transmisison
19	MISO exit fee regulatory asset amortization	(1,509,951)	-	(1,509,951)	MISO exit fee direct assigned to transmission
20	Year end adjustment	(1,909,033)	(1,262,118)	(167,200)	L. 35 ÷ L.34 total col x L.20, total col.
21	Annualized depreciation expenses under current rates	712,846	471,284	62,433	L. 35 ÷ L.34 total col x L.21, total col.
22	Labor adjustment	2,883,454	1,906,337	252,543	L. 35 ÷ L.34 total col x L.22, total col.
23	Pension & post retirement expense adjustment	(4,067,870)	(2,689,389)	(356,278)	L. 35 ÷ L.34 total col x L.23, total col.
24	Property insurance expense adjustment	1,079,050	713,392	94,507	L. 35 ÷ L.34 total col x L.24, total col.
25	Remove out of period items	(475,875)	(314,615)	(41,679)	L. 35 ÷ L.34 total col x L.25, total col.
26	Eliminate advertising expenses	(808,453)	(534,492)	(70,807)	L. 35 ÷ L.34 total col x L.26, total col.
27	Amortization of rate case expenses	(25,313)	(16,735)	(2,217)	L. 35 ÷ L.34 total col x L.27, total col.
28	Adjustment for injuries and damages FERC account 925	(1,233,028)	(815,191)	(107,993)	L. 35 ÷ L.34 total col x L.28, total col.
29	General Management Audit regulatory asset amortization	47,507	31,408	4,161	L. 35 ÷ L.34 total col x L.29, total col.
30	Federal & State Income Tax Adjustment	(2,427,596)	(1,604,956)	(212,617)	L. 35 ÷ L.34 total col x L.30, total col.
31	Federal & State Income Tax Interest Adjustment	145,218	96,008	12,719	L. 35 ÷ L.34 total col x L.31, total col.
32	Adjustment for tax basis depreciation reduction	(331,159)	(218,939)	(29,004)	L. 35 ÷ L.34 total col x L.32, total col.
33	Prior income tax true-ups & adjustments	(436,228)	(288,403)	(38,206)	L. 35 ÷ L.34 total col x L.33, total col.
34	Total Expense Adjustments	$ (20,994,252)	$ (13,835,798)	$ (5,438,023)	Sum of Ls.17 - 33
35	Rate Base	$ 3,500,935,146	$ 2,314,571,844	$ 306,623,826	C-3, pages 9-10, Net Rate Base, base, intermediate, peak
	Rate Base Adjustments:				
36	ECR Plan Eliminations	(183,667,066)	(121,427,733)	(16,086,187)	L. 35 ÷ L.35 total col x L.36, total col.
37	Adjustmentto Reflect Depreciation Reserve	(712,846)	(471,284)	(62,433)	L. 35 ÷ L.35 total col x L.37, total col.
38	Cash Working Capital	(5,709,964)	(3,775,026)	(500,098)	L. 35 ÷ L.35 total col x L.38, total col.
39	Net Adjusted Rate Base	$ 3,310,845,270	$ 2,188,897,801	$ 289,975,107	Sum of Ls.36 - 38

KU Exhibit M-3, tied to Cost of Service C-4, page 2 — Primary Distribution Unit Demand Costs

Note: Purple cells tie to Conroy Exhibit M3 Revised
Blue Cells tie to Conroy Exhibit C4 Revised
All other cells calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
	Conroy M-3, Page 2	Distribution Primary Substation Col. A amounts per M-3	Rate PS-P	Rate TOD-P	
1	Operation and Maintenance Expenses	$ 1,282,565	$ 230,630	$ 1,051,935	C-4, page 7-8: Distribution Substation, PS-P and TOD-P
2	Depreciation Expenses	824,947	148,341	676,606	C-4, page 11-12: Distribution Substation, PS-P and TOD-P
3	Accretion Expenses	(286)	(51)	(235)	C-4, page 13-14: Distribution Substation, PS-P and TOD-P
4	Property Taxes	93,400	16,795	76,605	C-4, page 15-16: Distribution Substation, PS-P and TOD-P
5	Other Taxes	48,600	8,739	39,861	C-4, page 17-18: Distribution Substation, PS-P and TOD-P
6	Expense Adjustments	(99,149)	$ (61,352)	$ (37,798)	L.1 ÷ [L.1 + L.9] x L.37
7	Sub-Total Substation Expenses	$ 2,150,076	$ 343,102	$ 1,806,974	Sum of Ls.1 - 6
8	Adjusted Rate Base	$ 17,444,711	$ 3,139,360	$ 14,305,351	L.53
	Conroy M-3, Page 2	Distribution Primary Lines Col. A amounts per M-3	Rate PS-P	Rate TOD-P	
9	Operation and Maintenance Expenses	$ 3,818,214	$ 686,587	$ 3,131,627	C-4, page 7-8: Distribution P Demand Lines, PS-P and TOD-P
10	Depreciation Expenses	1,336,113	240,259	1,095,855	C-4, page 11-12: Distribution P Demand Lines, PS-P and TOD-P
11	Accretion Expenses	(464)	(83)	(380)	C-4, page 13-14: Distribution P Demand Lines, PS-P and TOD-P
12	Property Taxes	151,273	27,202	124,072	C-4, page 15-16: Distribution P Demand Lines, PS-P and TOD-P
13	Other Taxes	78,715	14,154	64,560	C-4, page 17-18: Distribution P Demand Lines, PS-P and TOD-P
14	Expense Adjustments	(295,169)	$ (182,644)	$ (112,524)	L.9 ÷ [L.1 + L.9] x L.37
15	Sub-Total Lines Expenses	$ 5,088,683	$ 785,474	$ 4,303,209	Sum of Ls.9 - 14
16	Adjusted Rate Base	$ 28,253,706	$ 5,084,552	$ 23,169,154	L.54

			Expense Adjustments from Unit Cost schedules Rate PS-P	Rate TOD-P	
17	Expense Adjustments assigned to Distribution				
18	Eliminate DSM Expenses (allocate to demand & customer)	$ (207,004)	$ (85,849)	$ (121,155)	C-4, page 31-32 PS-P and TOD-P
19	Normalized storm damage expenses (allocate to demand & customer)	(40,796)	(7,447)	(33,349)	C-4, page 31-32 PS-P and TOD-P
20	Year end adjustment	$ (921,229)	$ 96,242	$ (1,017,471)	C-4, page 31-32 PS-P and TOD-P
21	Annualized depreciation expenses under current rates	125,518	21,427	104,091	C-4, page 31-32 PS-P and TOD-P
22	Labor adjustment	426,986	73,242	353,744	C-4, page 31-32 PS-P and TOD-P
23	Pension & post retirement expense adjustment	(602,376)	(103,327)	(499,049)	C-4, page 31-32 PS-P and TOD-P
24	Property insurance expense adjustment	187,887	32,102	155,785	C-4, page 31-32 PS-P and TOD-P
25	Remove out of period items	(82,704)	(14,133)	(68,571)	C-4, page 31-32 PS-P and TOD-P
26	Eliminate advertising expenses	(158,869)	(32,200)	(126,669)	C-4, page 31-32 PS-P and TOD-P
27	Amortization of rate case expenses	(5,169)	(872)	(4,297)	C-4, page 31-32 PS-P and TOD-P
28	Adjustment for injuries and damages FERC account 925	(214,698)	(36,683)	(178,015)	C-4, page 31-32 PS-P and TOD-P
29	General Management Audit regulatory asset amortization	9,702	1,637	8,065	C-4, page 31-32 PS-P and TOD-P
30	Federal & State Income Tax Adjustment	(544,875)	(1,905,438)	1,360,563	C-4, page 31-32 PS-P and TOD-P
31	Federal & State Income Tax Interest Adjustment	27,058	9,936	17,122	C-4, page 31-32 PS-P and TOD-P
32	Adjustment for tax basis depreciation reduction	(61,703)	(22,658)	(39,045)	C-4, page 31-32 PS-P and TOD-P
33	Prior income tax true-ups & adjustments	(81,280)	(29,847)	(51,433)	C-4, page 31-32 PS-P and TOD-P
34	Total of Other Expense Adjustments	$ (2,143,552)	$ (1,910,572)	$ 14,820	Sum of Ls.20 - 33

KU Exhibit M-3, tied to Cost of Service C-4, page 2 | Primary Distribution Unit Demand Costs

Note: Purple cells tie to Conroy Exhibit M3 Revised
Blue Cells tie to Conroy Exhibit C4 Revised
All other cells calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
	Conroy M-3, Page 2	Distribution Primary Substation	Rate PS-P	Rate TOD-P	
35	Total Primary portion of other expense adj	$ (160,114)	$ (161,290)	$ 1,176	L.48 ÷ L.38 x L.34
36	Total Primary portion of distribution exp adj	$ (234,204)	$ (82,706)	$ (151,498)	(L.18 + L.19) x (L.48÷ (L.48 + L.49))
37	Total Primary expense adjustments	$ (394,318)	$ (243,996)	$ (150,322)	Sum of Ls.35 - 36
38	Rate Base	$ 3,500,935,146	$ 103,973,077	$ 504,468,963	C-4, page 29-30 PS-P and TOD-P
39	Rate Base Adjustments:				
40	ECR Plan Eliminations	(183,667,066)	(6,407,840)	(31,571,854)	C-4, page 29-30 PS-P and TOD-P
41	Adjustmentto Reflect Depreciation Reserve	(712,846)	(21,427)	(104,091)	C-4, page 29-30 PS-P and TOD-P
42	Cash Working Capital	(5,709,964)	(126,906)	(587,414)	C-4, page 29-30 PS-P and TOD-P
43	Total Rate Base Adjustments	(190,089,876)	(6,556,173)	(32,263,359)	Sum of Ls.40 - 42
44	Adjusted Net Rate Base	$ 3,310,845,270	$ 97,416,904	$ 472,205,604	L.38 + L.43
45	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:		Rate PS-P	Rate TOD-P	
46	Substation Demand Rate Base		$ 3,350,639	$ 15,282,762	C-4, pp 5&6, PS-P and TOD-P Distribution Substation
47	Primary Lines Demand Rate Base		5,426,744	24,752,182	C-4, pp 5&6, PS-P and TOD-P Distribution Lines
48	Total Primary Demand Rate Base		$ 8,777,383	$ 40,034,943	Sum of Ls.46 - 47
49	Primary Customer Rate Base		1,123,899	794,537	C-4, pp 5-6 PS-P and TOD-P, P Customer Lines and Meters
50	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base		(553,471)	(2,560,438)	L.48 ÷ L.38 x L.43
51	Substation portion of rate base adjustment		(211,279)	(977,410)	L.46 ÷ L.48 x L.50
52	Lines portion of rate base adjustment		(342,191)	(1,583,028)	L.47 ÷ L.48 x L.50
53	Substation Adjusted Rate Base		$ 3,139,360	$ 14,305,351	L.46 + L.51
54	Lines Adjusted Rate Base		5,084,552	23,169,154	L.47 + L.52

KU Exhibit M3, tied to Cost of Service C4, page 3 — Secondary Distribution Unit Demand Costs

Note: Purple cells tie to Conroy Exhibit M3 Revised
Blue Cells tie to Conroy Exhibit C4 Revised
All other cells calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
	Conroy M-3, Page 2	Distribution Secondary Substations Col. A amounts per M3	Rate PS-S	Rate TOD-S	
1	Operation and Maintenance Expenses	$ 1,061,572	$ 924,784	$ 136,788	C-4, page 7-8: Distribution Substation, PS-S and TOD-S
2	Depreciation Expenses	682,804	594,822	87,982	C-4, page 11-12: Distribution Substation, PS-S and TOD-S
3	Accretion Expenses	(237)	(206)	(31)	C-4, page 13-14: Distribution Substation, PS-S and TOD-S
4	Property Taxes	77,306	67,345	9,961	C-4, page 15-16: Distribution Substation, PS-S and TOD-S
5	Other Taxes	40,226	35,043	5,183	C-4, page 17-18: Distribution Substation, PS-S and TOD-S
6	Expense Adjustments	(333,731)	(354,044)	20,313	L.1 ÷ [L.1 + L.9 + L.17] x L.45
7	Sub-Total Substation Expenses	$ 1,527,941	$ 1,267,743	$ 260,198	Sum of Ls.1 - 6
8	Adjusted Rate Base	$ 13,719,509	$ 11,954,198	$ 1,765,311	L.64
	Conroy M-3, Page 2	Distribution Secondary Lines Col. A amounts per M-3	Rate PS-S	Rate TOD-S	
9	Operation and Maintenance Expenses	$ 448,807	$ 389,871	$ 58,936	C-4, page 7-8: Distribution Lines, Secondary Demand, PS-S and TOD-S
10	Depreciation Expenses	157,051	136,428	20,623	C-4, page 11-12: Distribution Lines, Secondary Demand, PS-S and TOD-S
11	Accretion Expenses	(54)	(47)	(7)	C-4, page 13-14: Distribution Lines, Secondary Demand, PS-S and TOD-S
12	Property Taxes	17,781	15,446	2,335	C-4, page 15-16: Distribution Lines, Secondary Demand, PS-S and TOD-S
13	Other Taxes	9,252	8,037	1,215	C-4, page 17-18: Distribution Lines, Secondary Demand, PS-S and TOD-S
14	Expense Adjustments	(140,506)	(149,258)	8,752	L.9 ÷ [L.1 + L.9 + L.17] x L.45
15	Sub-Total Lines Expenses	$ 492,332	$ 400,478	$ 91,854	Sum of Ls.9 - 14
16	Adjusted Rate Base	$ 3,155,569	$ 2,741,778	$ 413,791	L.65
	Conroy M-3, Page 2	Distribution Secondary Transfor Col. A amounts per M-3	Rate PS-S	Rate TOD-S	
17	Operation and Maintenance Expenses	$ 440,959	$ 383,054	$ 57,905	C-4, page 7-8: Distribution Line Transformers, Demand, PS-S and TOD-S
18	Depreciation Expenses	552,781	480,192	72,589	C-4, page 11-12: Distribution Line Transformers, Demand, PS-S and TOD-S
19	Accretion Expenses	(192)	(167)	(25)	C-4, page 13-14: Distribution Line Transformers, Demand, PS-S and TOD-S
20	Property Taxes	62,585	54,367	8,218	C-4, page 15-16: Distribution Line Transformers, Demand, PS-S and TOD-S
21	Other Taxes	32,566	28,290	4,276	C-4, page 17-18: Distribution Line Transformers, Demand, PS-S and TOD-S
22	Expense Adjustments	(138,049)	(146,648)	8,599	L.17 ÷ [L.1 + L.9 + L.17] x L.45
23	Sub-Total Transformer Expenses	$ 950,650	$ 799,088	$ 151,562	Sum of Ls.17 - 22
24	Adjusted Rate Base	$ 11,060,396	$ 9,610,039	$ 1,450,356	L.66

KU Exhibit M3, tied to Cost of Service C4, page 3 — Secondary Distribution Unit Demand Costs

Note: Purple cells tie to Conroy Exhibit M3 Revised

25	Expense Adjustments assigned to Distribution				
26	Eliminate DSM Expenses (allocate to demand & customer)	$ (526,891)	$ (465,083)	$ (61,808)	C-4, page 31-32 PS-S and TOD-S
27	Normalized storm damage expenses (allocate to demand & customer)	(61,204)	(53,913)	(7,291)	C-4, page 31-32 PS-S and TOD-S
28	Year end adjustment	$ (810,203)	(875,402)	65,199	C-4, page 31-32 PS-S and TOD-S
29	Annualized depreciation expenses under current rates	110,673	95,915	14,758	C-4, page 31-32 PS-S and TOD-S
30	Labor adjustment	397,588	346,213	51,375	C-4, page 31-32 PS-S and TOD-S
31	Pension & post retirement expense adjustment	(560,903)	(488,424)	(72,479)	C-4, page 31-32 PS-S and TOD-S
32	Property insurance expense adjustment	166,105	143,978	22,127	C-4, page 31-32 PS-S and TOD-S
33	Remove out of period items	(73,173)	(63,441)	(9,732)	C-4, page 31-32 PS-S and TOD-S
34	Eliminate advertising expenses	(154,835)	(139,063)	(15,772)	C-4, page 31-32 PS-S and TOD-S
35	Amortization of rate case expenses	(4,449)	(3,876)	(573)	C-4, page 31-32 PS-S and TOD-S
36	Adjustment for injuries and damages FERC account 925	(189,808)	(164,523)	(25,285)	C-4, page 31-32 PS-S and TOD-S
37	General Management Audit regulatory asset amortization	8,351	7,275	1,076	C-4, page 31-32 PS-S and TOD-S
38	Federal & State Income Tax Adjustment	437,853	(563,650)	1,001,503	C-4, page 31-32 PS-S and TOD-S
39	Federal & State Income Tax Interest Adjustment	40,516	39,536	980	C-4, page 31-32 PS-S and TOD-S
40	Adjustment for tax basis depreciation reduction	(92,393)	(90,158)	(2,235)	C-4, page 31-32 PS-S and TOD-S
41	Prior income tax true-ups & adjustments	(121,708)	(118,764)	(2,944)	C-4, page 31-32 PS-S and TOD-S
42	Total of Other Expense Adjustments	$ (1,434,481)	$ (1,874,384)	$ 1,027,998	Sum of Ls.28 - 41
43	Total Secondary portion of other expense adj	$ (92,219)	$ (197,098)	$ 104,879	L.58 ÷ L.46 x L.42
44	Total Secondary portion of distribution exp adj	$ (520,067)	$ (452,852)	$ (67,215)	(L.26 + L.27) x (L.58÷ (L.58 + L.59))
45	Total Secondary expense adjustments	$ (612,286)	$ (649,950)	$ 37,664	Sum of Ls.43 - 44
46	Rate Base	$ 3,500,935,146	$ 466,728,220	$ 71,596,666	C-4, pp 5-6, PS-S and TOD-S total rate base
47	Rate Base Adjustments:				
48	ECR Plan Eliminations	$ (183,667,066)	$ (27,943,177)	$ (4,369,857)	C-4, page 29-30 PS-S and TOD-S
49	Adjustmentto Reflect Depreciation Reserve	(712,846)	(95,915)	(14,758)	C-4, page 29-30 PS-S and TOD-S
50	Cash Working Capital	(5,709,964)	(603,079)	(88,797)	C-4, page 29-30 PS-S and TOD-S
51	Total Rate Base Adjustments	(33,115,583)	(28,642,171)	(4,473,412)	Sum of Ls.48 - 50
52	Adjusted Net Rate Base	$ 3,310,845,270	$ 438,086,049	$ 67,123,254	L.46 + L.51
53	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:		Rate PS-S	Rate TOD-S	
54	Substation Demand Rate Base		$ 13,435,476	$ 1,987,292	C-4, pp 5-6, PS-S and TOD-S Distribution Substation
55	Primary Lines Demand Rate Base		$ 21,760,290	$ 3,218,647	C-4, pp 5-6, PS-S and TOD-S Distribution Primary Lines
56	Secondary Lines Demand Rate Base		3,081,519	465,824	C-4, pp 5-6, PS-S and TOD-S Distribution Secondary
57	Secondary Transformers Lines Demand Rate Base		10,800,846	1,632,733	C-4, pp 5-6, PS-S and TOD-S Distribution Line Transformers
58	Total Secondary Demand Rate Base		$ 49,078,131	$ 7,304,496	Sum of Ls.53 - 56
59	Secondary Customer Rate Base		7,168,405	204,755	C-4, pp 5,6 PS-S and TOD-S, Primary and Secondary Lines, Transformers, Meters & Services
60	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base		(3,011,826)	(456,390)	L.58 ÷ L.46 x L.51
61	Substation portion of rate base adjustment		(1,481,278)	(221,981)	L.54 ÷ L.58 - L.55 x L.60
62	Lines portion of rate base adjustment		(339,741)	(52,033)	L.56 ÷ L.58 - L.55 x L.60
63	Transformers portion of rate base adjustment		(1,190,807)	(182,377)	L.57 ÷ L.58 - L.55 x L.61
64	Substation Adjusted Rate Base		$ 11,954,198	$ 1,765,311	L.54 + L.61
65	Lines Adjusted Rate Base		2,741,778	413,791	L.56 + L.62
66	Transformers Adjusted Rate Base		9,610,039	1,450,356	L.57 + L.63

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 4

Responding Witness: John J. Spanos

Q-4. Refer to pages 111-4 and 111-5 of Exhibit JJS-KU to the Direct Testimony of John J. Spanos ("Spanos Testimony"). In this proceeding KU has determined that the actual net salvage for the Tyrone units and the Green River Units is equal to negative 10 percent of their original costs. Explain why KU estimates net salvage to be greater than negative 10 percent for each of the other Steam Production Plant Units listed on these pages other than Pineville Unit 3.

A-4. The net salvage estimates as shown on pages III-4 and III-5 include components for both terminal net salvage and interim net salvage. The terminal net salvage estimates are negative 10 percent, while the interim net salvage estimates vary by plant account. The development of the composite estimates shown on pages III-4 and III-5 can be found on pages III-210 through III-212 of the depreciation study.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 5

Responding Witness: Shannon L. Charnas / John J. Spanos

Q-5. Refer to page 111-5 of Exhibit JJS-KU to the Spanos Testimony, page 111-5 of the depreciation study attached to the testimony submitted by Mr. Spanos in Case No. 2007-00565,' and Exhibit 7 of the Settlement Agreement filed by KU on January 13, 2009 in Case No. 2007-00565.

a. State whether KU has used the depreciation rates in Exhibit 7 of the Settlement Agreement to calculate its depreciation accruals since the Commission's approval of the Settlement Agreement.
b. If the response to part a. of this request is affirmative, explain why the book depreciation reserve shown on page III-5 of Exhibit JJS-KU for account 316, Tyrone Units 1 and 2 as of December 31, 2011, includes a negative 10 percent net salvage accrual when there was no salvage assigned to this account on page III-5 of the depreciation study filed in Case No. 2007-00565, which formed the basis for the depreciation rates included in the Settlement Agreement.

A-5. a. KU has used the depreciation rates from the Settlement Agreement to calculate its annual depreciation accruals since the approval of the Settlement Agreement.

b. For certain generating units that were either retired or approaching retirement, the reserve position at the date of the depreciation study was either too low (and thus required to be recovered over a short period of time), or exceeded the original cost of plant in service less net salvage. For example, for Account 316, Tyrone Units 1 and 2 had a book reserve amount of $45,825 compared with $50,127 in original cost, but had no remaining life to recover the un-depreciated costs. Conversely, for the same account Green River Units 1 and 2 had a book reserve amount of $116,207, compared with $84,750 in original cost. In order to better match the book reserve with the depreciable lives and expected net salvage for these units, reserve amounts were transferred between these and other units within the same FERC account. The transferred amounts will be recovered over the remaining lives of the other units.

It is not uncommon for reserves to be out of balance with the original cost for certain production plant units, due both to changing circumstances (e.g. early retirements), and to regulatory lag. The treatment in the depreciation study of rebalancing the reserve with transfers within each FERC account is a common and accepted practice in the industry.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 6

Responding Witness: Paul W. Thompson

Q-6. Refer to page 9, lines 15-21 of the Testimony of Paul W. Thompson, and the responses to Items 21 and 22 of Commission Staff's Second Request for Information ("Staff's Second Request").

a. Given the experience during the first year of operation of Trimble County Unit 2 ("TC2"), explain why KU and its sister company, Louisville Gas and Electric Company ("LG&E"), expect the test-year level of operation and maintenance costs associated with TC2 to reflect the "going-forward operation and maintenance expenses associated with operating the generating unit . . . ."

b. The response to Item 21 identifies several matters that were addressed during a spring 2012 planned outage of TC2 while the attachment to the response to Item 22 shows the level of expenses, by account, incurred for the operation of TC2 during the test year. Explain whether any of the specific expenses are expected to decline as a result of the activities performed during the outage.

A-6. a. The amount of O&M expense for TC2 during the test year was approximately $11 million on a net (of IMEA/IMPA share) basis. Costs for 2012 and 2013 are expected to be marginally higher than that, at $13 million and $12 million respectively, with the level for 2014 projected at $16 million. The costs increase over time from the test year due to inflation and additional maintenance including planned outages, as would be expected in the life cycle of any coal-fired unit.

b. The spring 2012 outage was primarily for the purpose of inspecting key components prior to the expiration of the warranty, and for addressing known issues that were impacting operations. It is not expected that the resolution of those issues will lower expenses, but rather will improve reliability. As noted in part a above, the level of expenses for TC2 is expected to increase slightly in 2012 and 2013 compared to the test year amount.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 7

Responding Witness: Robert M. Conroy

Q-7. Refer to the responses to Items 1-5 of Staff's Second Request, all of which describe proposed changes which are intended to provide clarity. Explain whether the clarifying changes referenced in each of these responses represent KU's existing practice which it desires to make clear in its tariff, or if the changes represent changes in KU's current practices or provision of services.

A-7. The response to PSC 2-1, clarifies the determination of the 50 kW limit for the General Service rate's availability to customers by defining the limit as a twelve-month average. That has been the practice with some flexibility to allow for moving customers whose average kW load was obviously above the limit but would benefit from another rate. That same flexibility allowed a customer whose average load was barely above 50 kW, then barely below 50 kW to be left on the rate most advantageous to the customer.

In the response to PSC 2-2, the first sentence should be corrected.

> *The text change in the AVAILABILITY OF SERVICE section of proposed P.S.C. No. 16, Original Sheet No. 15, limits the load that can be served on the PS (Power Service) rate to secondary customers whose 12-month-average monthly minimum secondary loads ~~do not~~ exceed 50 kW and whose secondary service or primary service 12-month-average maximum loads do not exceed 250 kW.*

The clarification is of the determination of the 50 kW minimum limit for secondary customer and the 250 kW maximum limit the Power Service rate's availability to customers by defining those limits as a twelve-month average. That has been the practice with some flexibility as noted above.

The response to PSC 2-3, clarifies the determination of the 250 kW minimum limit and the 5,000 kW maximum limit of the Time-of-Day Secondary Service rate's availability to customers by defining those limits as a twelve-month average. That has been the practice with some flexibility as noted above.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 8

Responding Witness: Robert M. Conroy

Q-8. Refer to the response to Item 6 of Staff's Second Request, page 2 of 5, the LS Underground Service section.

a. KU states that the policy of customers being responsible for ditching, back-filling, and maintaining conduit will stay in effect even though the language is being deleted from the tariff. KU also states that it is being replaced with more generic language on proposed Sheet No. 35.1.

1) Explain whether KU has any concerns about enforcing a policy that will not be included in its tariff.

2) Provide the generic language on proposed Sheet No. 35.1 which is meant to replace the current language.

b. The response states that "[t]he language referring to Custom Ordered Styles was deleted. Customers choosing to install their own lighting will be billed base (sic) on KU's LE tariff."

1) State whether any current customers will be moved to the Lighting Energy ("LE") tariff as a result of the proposed changes.

2) KU's LE tariff states that it is available to "municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems . . . ." Explain whether KU intends for individuals who choose to install their own lighting to be eligible to take service under the LE tariff.

A-8. In harmonizing the tariffs some changes in wording were made to allow for continued differences in KU's operations and LG&E's operations.

a. The proposed generic language is the last sentence of the first paragraph at the top of Original Sheet No. 35.1, "… Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of the Company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the overhead lighting system." This allows each company to continue their normal practice of either accepting a cash contribution (LG&E) or a work contribution (KU).

   1) KU has no concerns about enforcing the policy since the proposed language adequately addresses the issue.

   2) See a. above.

b.

   1) No current customers will be moved to Rate LE as a result of the proposed tariff change unless those customers assume ownership of lighting facilities currently owned by KU.

   2) KU does not intend to alter the AVAILABILITY OF SERVICE term applicable to Rate LE so that individuals owning their own lighting facilities may be served under Rate LE. Such customers may receive power for their lighting through their standard service meter.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 9

Responding Witness: Robert M. Conroy

Q-9. Refer to the response to Item 6 of Staff's Second Request, pages 3-4 of 5, the LS Term and Conditions section. Explain why it is necessary to add language prohibiting the temporary suspension of lighting service.

A-9. KU's practice, if temporary turnoffs were allowed, would be to remove the facilities; pole and fixture as appropriate. KU believes the temporary suspension of lighting would be administratively burdensome. In addition, if temporary turnoffs were allowed, the Company would have assets in services with no revenue to cover their costs. Lights would be reported as failing by the public when they were requested to be turned-off by a customer. Historically this has not been a problem. However, given the economic issues faced by some customers, KU has received requests from municipals for such an action in order to reduce their monthly expenses.

KENTUCKY UTILITIES COMPANY

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Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 10

Responding Witness: Paul W. Thompson

Q-10. Refer to the response to Item 23 of Staff's Second Request. Confirm that the costs shown in the attachment for the 19 additional people hired to work at TC2 since the test year in KU's last rate case are part of the expenses provided in the response to Item 22 of Staff's Second Request.

A-10. Yes, the labor costs associated with the additional 19 people hired for Trimble County 2 are included in the expense amount provided in the response to KU PSC 2-22.

KENTUCKY UTILITIES COMPANY

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Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 11

Responding Witness: Paul W. Thompson

Q-11. Refer to the response to Item 24 of Staff's Second Request. In the same format used in the attachment to the response, provide the maintenance expense incurred by KU in calendar year 2011 and the test year. Also, provide the actual maintenance expense incurred in the first half of 2012 and the projected expense for the remainder of 2012.

A-11. See attached.

Rate Case Analysis - Outages (Nonlabor)

US$ 000

	Actuals 2011	TYE 31-Mar-2012	Actual First Half 2012	Projection Second Half 2012	Projection 2012
Trimble Co 2	233	292	1,126	(63)	1,063
Total	233	292	1,126	(63)	1,063
Ghent 1	1,737	3,709	3,219	30	3,249
Ghent 2	334	1,587	7,912	156	8,068
Ghent 3	9,851	9,124	3,120	(0)	3,120
Ghent 4	402	594	181	2,057	2,238
Total	12,324	15,014	14,433	2,242	16,675
Brown 1	326	333	21	663	684
Brown 1, 2, 3	79	65	6	(0)	6
Brown 2	1,147	1,162	9	639	649
Brown 3	2,003	1,827	50	6,763	6,813
Total	3,555	3,388	86	8,065	8,152
Green River 3	1	(0)	41	972	1,013
Green River 4	1,925	1,935	302	42	344
Total	1,926	1,935	343	1,014	1,357
Tyrone 1, 2	-	-	-	-	-
Tyrone 3	-	-	-	-	-
Total	-	-	-	-	-
Total Steam	18,037	20,629	15,988	11,258	27,246

Rate Case Analysis - Outages (Nonlabor)

US$ 000

	Actuals 2011	TYE 31-Mar-2012	Actual First Half 2012	Projection Second Half 2012	Projection 2012
Trimble Co 5	-	-	-	4	4
Trimble Co 6	-	-	-	4	4
Trimble Co 7	-	-	-	3	3
Trimble Co 8	-	-	-	3	3
Trimble Co 9	(2)	(2)	-	3	3
Trimble Co 10	-	-	-	3	3
Total	(2)	(2)	-	21	21
Paddy'S Run 13	500	20	(5)	26	21
					-
Brown 5	81	20	-	-	-
Brown 6	5	(16)	16	-	16
Brown 7	5	(14)	36	41	77
Brown 8	-	-	-	-	-
Brown 9	-	-	-	50	50
Brown 10	-	-	-	-	-
Haefling 1	3	5	2	10	12
Haefling 2	3	3	-	30	30
Haefling 3	3	3	-	30	30
Total	100	0	55	161	216
Total CTs	598	19	49	208	257
Dix Dam	-				
Grand Total	18,636	20,647	16,038	11,466	27,503

KENTUCKY UTILITIES COMPANY

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Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 12

Responding Witness: Lonnie E. Bellar

Q-12. Refer to the response to Item 47.c. of Staff's Second Request. Explain the increase in off-system sales and margins in 2011 as compared to 2010.

A-12. While many factors can influence the year to year changes in OSS volumes and margins, the overwhelming driver of why 2011 sales margins and volumes were greater than 2010 was due to the additional generation from Trimble County 2 when it became available for dispatch in January 2011.

KENTUCKY UTILITIES COMPANY

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Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 13

Responding Witness: John J. Spanos

Q-13. Refer to the responses to Items 49, 50, and 51 of Staff's Second Request, all of which relate to depreciation with 50 and 51 specifically relating to the depreciation and planned retirements of the Green River and Tyrone generating units.

a. The response to Item 50.b. indicates that each generating unit is expected to have a net negative 10 percent salvage value when retired. The response to Item 51.c. states that no estimate of salvage has been developed since there is currently no intention to take the facilities down to a natural state. Given KU's plan to stabilize rather than dismantle and remove these generating facilities, explain why the depreciation rates for these units should include a component for negative net salvage.

b. For each of the Tyrone and Green River utility plant items for which a proposed depreciation rate and related expense is shown in the response to Item 49, provide the depreciation rate and depreciation expense based on an expected salvage value of zero when the units are retired.

A-13. a. While the Company has no current plans to take the facilities down to a natural state, there are still significant costs to stabilizing the facilities. As discussed in the response to PSC 2-51(b), KU currently estimates costs to stabilize the Tyrone and Green River facilities to be $3 million and $5 million, respectively. As the response indicates, these are preliminary estimates based on the more detailed estimates of stabilizing the Cane Run 1-3 facilities. Further, while there are currently no plans to immediately dismantle these plants, there is the possibility of dismantlement in the future (as is the case with Paddy's Run and Canal), which would lead to much higher costs than included in the response to PSC 2-51(b). As such, the 10 percent negative net salvage used in the depreciation study represents a reasonable estimate of the costs associated with retiring these facilities.

b. See attached for the depreciation rates and expense for the Tyrone and Green River plants using zero percent net salvage. Note that as discussed in the response to Question No. 5(b), the book reserve for certain Tyrone and Green River units were rebalanced to better match the retirement dates and net salvage estimates for each unit. The same book reserve amounts are used in the attached file.

   Additionally, note that the depreciation rates and accruals in the attached file will not recover any of the costs expected to stabilize these plants upon retirement that were discussed in the response to PSC 2-51(b). Instead, under a scenario with zero net salvage these costs would be recovered by future customers that would not benefit from the use of these facilities.

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DEPRECIABLE PLANT									
	INTANGIBLE PLANT									
302.00	FRANCHISES AND CONSENTS	20-SQ		0	55,918.83	21,074.00	34,845	10,503	18.78	3.3
303.00	MISCELLANEOUS INTANGIBLE PLANT	5-SQ		0	18,338,712.02	7,484,852.00	10,853,860	2,801,459	15.28	3.9
303.10	CCS SOFTWARE	SQUARE	*	0	40,210,208.29	10,240,838.00	29,969,370	3,995,916	9.94	7.5
	TOTAL INTANGIBLE PLANT				**58,604,839.14**	**17,746,764**	**40,858,075**	**6,807,878**	**11.62**	
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	TRIMBLE COUNTY UNIT 2	100-S1	*	(15)	106,290,580.94	18,699,136	103,535,032	2,021,312	1.90	51.2
	TRIMBLE COUNTY UNIT 2 SCRUBBER	100-S1	*	(15)	5,522,306.98	2,689,746	3,660,907	75,374	1.36	48.6
	SYSTEM LABORATORY	100-S1	*	(1)	824,968.82	609,422	223,797	8,170	0.99	27.4
	TYRONE UNIT 3	100-S1	*	0	5,608,825.07	6,169,708	(560,883)	0	-	-
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	0	583,381.44	641,720	(58,339)	0	-	-
	GREEN RIVER UNIT 3	100-S1	*	0	2,821,436.66	3,103,580	(282,143)	0	-	-
	GREEN RIVER UNIT 4	100-S1	*	0	5,476,054.30	4,320,817	1,155,237	289,097	5.28	4.0
	GREEN RIVER UNITS 1 AND 2	FULLY ACCRUED	*	0	2,560,764.18	2,816,841	(256,077)	0	-	-
	BROWN UNIT 1	100-S1	*	(11)	4,703,189.76	4,861,747	358,794	21,822	0.46	16.4
	BROWN UNIT 2	100-S1	*	(11)	2,232,100.04	2,028,873	448,758	20,077	0.90	22.4
	BROWN UNIT 3	100-S1	*	(11)	21,039,674.36	14,064,263	9,289,776	400,691	1.90	23.2
	BROWN UNITS 1, 2 AND 3 SCRUBBER	100-S1	*	(11)	43,917,221.15	1,760,616	46,987,499	2,010,590	4.58	23.4
	PINEVILLE UNIT 3	FULLY ACCRUED	*	(10)	16,204.29	17,825	0	0	-	-
	GHENT UNIT 1 SCRUBBER	100-S1	*	(12)	8,483,789.23	6,985,454	2,516,390	113,954	1.34	22.1
	GHENT UNIT 1	100-S1	*	(12)	18,842,151.21	18,621,064	2,482,145	111,264	0.59	22.3
	GHENT UNIT 2	100-S1	*	(12)	16,011,012.98	14,142,566	3,789,769	176,840	1.10	21.4
	GHENT UNIT 3	100-S1	*	(12)	42,177,125.67	30,851,643	16,386,738	671,100	1.59	24.4
	GHENT UNIT 4	100-S1	*	(12)	31,022,090.50	14,920,226	19,824,515	770,327	2.48	25.7
	GHENT UNIT 2 SCRUBBER	100-S1	*	(12)	15,817,337.72	12,919,945	4,795,473	218,174	1.38	22.0
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				333,950,215.30	160,225,192	214,297,388	6,908,792	2.07	31.0

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
312.00	BOILER PLANT EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	60-R2.5	*	(15)	505,158,968.57	44,042,332	536,890,482	11,040,635	2.19	48.6
	TRIMBLE COUNTY UNIT 2 SCRUBBER	60-R2.5	*	(15)	70,735,319.61	11,271,211	70,074,407	1,453,909	2.06	48.2
	TYRONE UNIT 3	60-R2.5	*	0	13,993,285.78	11,103,677	2,889,609	724,825	5.18	4.0
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	0	421,899.96	464,090	(42,190)	0	-	-
	GREEN RIVER UNIT 3	60-R2.5	*	0	12,145,770.44	9,725,542	2,420,228	610,553	5.03	4.0
	GREEN RIVER UNIT 4	60-R2.5	*	0	25,165,914.24	20,127,163	5,038,751	1,265,686	5.03	4.0
	GREEN RIVER UNITS 1 AND 2	FULLY ACCRUED	*	0	349,297.88	384,228	(34,930)	0	-	-
	BROWN UNIT 1	60-R2.5	*	(11)	45,302,489.09	26,739,197	23,546,566	1,471,865	3.25	16.0
	BROWN UNIT 2	60-R2.5	*	(11)	41,956,868.14	19,641,359	26,930,765	1,252,209	2.98	21.5
	BROWN UNIT 3	60-R2.5	*	(11)	142,628,390.37	71,929,055	86,388,458	3,809,860	2.67	22.7
	BROWN UNITS 1, 2 AND 3 SCRUBBER	60-R2.5	*	(11)	323,725,098.68	18,469,817	340,865,043	14,820,202	4.58	23.0
	PINEVILLE UNIT 3	FULLY ACCRUED	*	(10)	236,470.42	260,117	0	0	-	-
	GHENT UNIT 1 SCRUBBER	60-R2.5	*	(12)	144,202,759.28	34,075,530	127,431,560	5,799,995	4.02	22.0
	GHENT UNIT 1	60-R2.5	*	(12)	198,785,055.46	96,800,340	125,838,922	5,834,075	2.93	21.6
	GHENT UNIT 2	60-R2.5	*	(12)	98,446,686.35	73,285,978	36,974,311	1,779,312	1.81	20.8
	GHENT UNIT 3	60-R2.5	*	(12)	254,967,909.72	146,662,379	138,901,680	5,879,680	2.31	23.6
	GHENT UNIT 4	60-R2.5	*	(12)	267,856,280.18	128,461,343	171,537,691	6,953,070	2.60	24.7
312, cont.	GHENT UNIT 2 SCRUBBER	60-R2.5	*	(12)	93,278,511.28	55,024,079	49,447,854	2,270,953	2.43	21.8
	GHENT UNIT 3 SCRUBBER	60-R2.5	*	(12)	127,988,949.01	24,898,056	118,449,567	4,782,967	3.74	24.8
	GHENT UNIT 4 SCRUBBER	60-R2.5	*	(12)	307,100,358.50	41,271,827	302,680,575	11,768,189	3.83	25.7
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				2,674,446,282.96	834,637,320	2,166,229,349	81,517,985	3.05	26.6
314.00	TURBOGENERATOR UNITS									
	TRIMBLE COUNTY UNIT 2	55-S1.5	*	(15)	83,994,732.76	12,471,959	84,121,984	1,836,110	2.19	45.8
	TYRONE UNIT 3	55-S1.5	*	0	4,805,513.66	3,825,756	979,758	245,664	5.11	4.0
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	0	68,205.72	75,026	(6,820)	0	-	-
	GREEN RIVER UNIT 3	55-S1.5	*	0	4,562,193.51	4,064,201	497,993	124,692	2.73	4.0
	GREEN RIVER UNIT 4	55-S1.5	*	0	10,390,485.90	9,545,563	844,923	211,553	2.04	4.0
	BROWN UNIT 1	55-S1.5	*	(11)	7,512,824.95	4,893,897	3,445,339	215,514	2.87	16.0
	BROWN UNIT 2	55-S1.5	*	(11)	12,299,721.87	8,687,176	4,965,515	228,841	1.86	21.7
	BROWN UNIT 3	55-S1.5	*	(11)	29,293,398.16	20,414,202	12,101,470	543,748	1.86	22.3
	GHENT UNIT 1	55-S1.5	*	(12)	36,687,321.40	20,194,109	20,895,691	978,789	2.67	21.3
	GHENT UNIT 2	55-S1.5	*	(12)	30,417,591.79	20,815,737	13,251,966	682,670	2.24	19.4
	GHENT UNIT 3	55-S1.5	*	(12)	42,595,556.80	28,152,257	19,554,767	887,493	2.08	22.0
	GHENT UNIT 4	55-S1.5	*	(12)	57,036,973.14	32,047,642	31,833,768	1,388,323	2.43	22.9
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				319,664,519.66	165,187,525	192,486,354	7,343,397	2.30	26.2

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	70-S3	*	(15)	41,600,356.80	4,958,709	42,881,701	836,186	2.01	51.3
	TRIMBLE COUNTY UNIT 2 SCRUBBER	70-S3	*	(15)	1,415,469.10	653,351	974,438	22,036	1.56	44.2
	TYRONE UNIT 3	70-S3	*	0	2,081,692.71	1,087,407	994,286	251,932	12.10	3.9
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	0	99,210.72	109,132	(9,921)	0	-	-
	GREEN RIVER UNIT 3	70-S3	*	0	1,205,362.18	554,397	650,965	164,105	13.61	4.0
	GREEN RIVER UNIT 4	70-S3	*	0	2,695,328.66	1,846,556	848,773	215,029	7.98	3.9
	BROWN UNIT 1	70-S3	*	(11)	3,859,109.33	3,259,464	1,024,147	62,118	1.61	16.5
	BROWN UNIT 2	70-S3	*	(11)	2,165,576.99	1,331,430	1,072,360	47,686	2.20	22.5
	BROWN UNIT 3	70-S3	*	(11)	8,597,465.88	6,533,915	3,009,272	128,146	1.49	23.5
	BROWN UNITS 1, 2 AND 3 SCRUBBER	70-S3	*	(11)	29,503,821.45	1,205,108	31,544,134	1,342,875	4.55	23.5
	GHENT UNIT 1 SCRUBBER	70-S3	*	(12)	13,292,784.70	3,266,572	11,621,347	517,122	3.89	22.5
	GHENT UNIT 1	70-S3	*	(12)	8,872,543.26	8,274,863	1,662,385	77,332	0.87	21.5
	GHENT UNIT 2	70-S3	*	(12)	13,858,388.53	10,602,781	4,918,614	229,310	1.65	21.4
	GHENT UNIT 3	70-S3	*	(12)	30,932,405.42	22,826,297	11,817,997	490,361	1.59	24.1
	GHENT UNIT 4	70-S3	*	(12)	24,412,796.92	16,503,145	10,839,188	429,536	1.76	25.2
	GHENT UNIT 2 SCRUBBER	70-S3	*	(12)	1,155,753.06	73,909	1,220,534	54,270	4.70	22.5
	GHENT UNIT 3 SCRUBBER	70-S3	*	(12)	12,041,998.28	1,992,181	11,494,857	451,284	3.75	25.5
	GHENT UNIT 4 SCRUBBER	70-S3	*	(12)	3,844,595.46	381,019	3,924,928	148,278	3.86	26.5
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				201,634,659.45	85,460,236	140,490,005	5,467,606	2.71	25.7
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	70-R1.5	*	(15)	3,502,446.96	126,166	3,901,648	81,004	2.31	48.2
	SYSTEM LABORATORY	70-R1.5	*	(1)	2,763,048.67	790,095	2,000,584	74,526	2.70	26.8
	TYRONE UNIT 3	70-R1.5	*	0	553,355.01	251,724	301,631	76,135	13.76	4.0
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	0	50,126.84	55,140	(5,013)	0	-	-
	GREEN RIVER UNIT 3	70-R1.5	*	0	152,146.47	101,809	50,337	12,702	8.35	4.0
	GREEN RIVER UNIT 4	70-R1.5	*	0	2,408,142.84	1,418,850	989,293	249,274	10.35	4.0
	GREEN RIVER UNITS 1 AND 2	FULLY ACCRUED	*	0	84,749.53	93,224	(8,474)	0	-	-
	BROWN UNIT 1	70-R1.5	*	(11)	432,577.58	351,287	128,874	8,059	1.86	16.0
	BROWN UNIT 2	70-R1.5	*	(11)	106,658.32	109,842	8,549	395	0.37	21.6
	BROWN UNIT 3	70-R1.5	*	(11)	5,070,448.32	2,925,174	2,703,024	121,490	2.40	22.2
316, cont.	GHENT UNIT 1 SCRUBBER	70-R1.5	*	(12)	1,033,027.09	834,195	322,795	15,091	1.46	21.4
	GHENT UNIT 1	70-R1.5	*	(12)	1,747,526.86	1,578,287	378,943	18,058	1.03	21.0
	GHENT UNIT 2	70-R1.5	*	(12)	1,500,525.31	1,397,086	283,502	13,774	0.92	20.6
	GHENT UNIT 3	70-R1.5	*	(12)	3,150,437.55	2,534,754	993,736	42,799	1.36	23.2
	GHENT UNIT 4	70-R1.5	*	(12)	7,455,181.33	2,842,039	5,507,764	221,851	2.98	24.8
	TOTAL ACCOUNT 316 - MISCELLANEOUS POWER PLANT EQUIPMENT				30,010,398.68	15,409,672	17,557,193	935,158	3.12	18.8
	TOTAL STEAM PRODUCTION PLANT				**3,559,706,076.05**	**1,260,919,945**	**2,731,060,289**	**102,172,938**	**2.87**	

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	HYDRAULIC PRODUCTION PLANT									
330.10	LAND RIGHTS									
	DIX DAM	100-R4	*	0	879,311.47	879,311	0	0	-	-
	TOTAL ACCOUNT 330.1 - LAND RIGHTS				879,311.47	879,311	0	0	-	-
331.00	STRUCTURES AND IMPROVEMENTS									
	DIX DAM	90-S2.5	*	(6)	616,526.69	353,805	299,713	10,702	1.74	28.0
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS				616,526.69	353,805	299,713	10,702	1.74	28.0
332.00	RESERVOIRS, DAMS AND WATERWAY									
	DIX DAM	100-S2.5	*	(6)	21,603,969.66	6,697,620	16,202,588	558,948	2.59	29.0
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS AND WATERWAYS				21,603,969.66	6,697,620	16,202,588	558,948	2.59	29.0
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	DIX DAM	75-R3	*	(6)	4,430,624.31	19,710	4,676,752	166,967	3.77	28.0
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES AND GENERATORS				4,430,624.31	19,710	4,676,752	166,967	3.77	28.0
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	DIX DAM	40-L2.5	*	(6)	578,333.28	90,045	522,988	21,138	3.65	24.7
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT				578,333.28	90,045	522,988	21,138	3.65	24.7
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	DIX DAM	35-L1	*	(6)	297,023.86	85,989	228,856	13,551	4.56	16.9
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT				297,023.86	85,989	228,856	13,551	4.56	16.9
336.00	ROADS, RAILROADS AND BRIDGES									
	DIX DAM	55-R4	*	(6)	176,359.59	49,946	136,995	7,394	4.19	18.5
	TOTAL ACCOUNT 336 - ROADS, RAILROADS & BRIDGES				176,359.59	49,946	136,995	7,394	4.19	18.5
	TOTAL HYDRAULIC PRODUCTION PLANT				**28,582,148.86**	**8,176,426**	**22,067,892**	**778,700**	**2.72**	

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	OTHER PRODUCTION PLANT									
340.10	LAND RIGHTS									
	BROWN CT GAS PIPELINE	SQUARE	*	0	176,409.31	99,438	76,971	3,947	2.24	19.5
	TOTAL ACCOUNT 340.1 - LAND AND LAND RIGHTS				176,409.31	99,438	76,971	3,947	2.24	19.5
341.00	STRUCTURES AND IMPROVEMENTS									
	TRIMBLE COUNTY CT 5	40-R2.5	*	(5)	3,740,231.32	1,170,949	2,756,294	144,756	3.87	19.0
	TRIMBLE COUNTY CT 6	40-R2.5	*	(5)	3,588,684.24	1,130,371	2,637,747	138,671	3.86	19.0
	TRIMBLE COUNTY CT 7	40-R2.5	*	(5)	3,559,154.97	909,260	2,827,853	135,304	3.80	20.9
	TRIMBLE COUNTY CT 8	40-R2.5	*	(5)	3,548,851.71	906,628	2,819,666	134,912	3.80	20.9
	TRIMBLE COUNTY CT 9	40-R2.5	*	(5)	3,655,976.41	923,545	2,915,230	139,485	3.82	20.9
	TRIMBLE COUNTY CT 10	40-R2.5	*	(5)	3,653,029.99	922,801	2,912,880	139,372	3.82	20.9
	BROWN CT 5	40-R2.5	*	(5)	775,081.85	270,065	543,771	30,044	3.88	18.1
	BROWN CT 6	40-R2.5	*	(5)	192,814.02	67,757	134,698	8,200	4.25	16.4
	BROWN CT 7	40-R2.5	*	(5)	544,965.97	207,252	364,962	22,379	4.11	16.3
	BROWN CT 8	40-R2.5	*	(5)	2,012,654.95	1,151,811	961,477	76,440	3.80	12.6
	BROWN CT 9	40-R2.5	*	(5)	4,641,054.86	2,628,903	2,244,205	130,408	2.81	17.2
	BROWN CT 10	40-R2.5	*	(5)	1,865,718.20	995,177	963,827	55,973	3.00	17.2
	BROWN CT 11	40-R2.5	*	(5)	1,895,013.50	960,868	1,028,896	75,771	4.00	13.6
	HAEFLING UNITS 1, 2 AND 3	40-R2.5	*	(5)	434,853.46	87,070	369,526	44,528	10.24	8.3
	PADDY'S RUN GENERATOR 13	40-R2.5	*	(5)	1,910,327.76	665,405	1,340,439	74,097	3.88	18.1
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS				36,018,413.21	12,997,862	24,821,471	1,350,340	3.75	18.4
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
	TRIMBLE COUNTY CT 5	45-R2.5	*	(5)	239,584.43	76,081	175,483	9,049	3.78	19.4
	TRIMBLE COUNTY CT 6	45-R2.5	*	(5)	239,245.54	75,986	175,222	9,036	3.78	19.4
	TRIMBLE COUNTY CT GAS PIPELINE	45-R2.5	*	(5)	4,850,114.73	1,572,837	3,519,783	166,771	3.44	21.1
	TRIMBLE COUNTY CT 7	45-R2.5	*	(5)	578,059.38	149,364	457,598	21,494	3.72	21.3
	TRIMBLE COUNTY CT 8	45-R2.5	*	(5)	576,385.74	148,931	456,274	21,431	3.72	21.3
	TRIMBLE COUNTY CT 9	45-R2.5	*	(5)	593,786.01	151,730	471,745	22,158	3.73	21.3
	TRIMBLE COUNTY CT 10	45-R2.5	*	(5)	622,872.60	157,134	496,882	23,324	3.74	21.3
	BROWN CT 5	45-R2.5	*	(5)	795,787.89	126,367	709,210	38,072	4.78	18.6
	BROWN CT 6	45-R2.5	*	(5)	406,460.01	17,424	409,359	24,066	5.92	17.0
	BROWN CT 7	45-R2.5	*	(5)	405,870.95	12,973	413,191	24,294	5.99	17.0
	BROWN CT 8	45-R2.5	*	(5)	252,005.73	22,171	242,435	18,266	7.25	13.3
	BROWN CT 9	45-R2.5	*	(5)	2,018,753.68	903,046	1,216,645	67,309	3.33	18.1
	BROWN CT 10	45-R2.5	*	(5)	264,130.81	29,700	247,637	13,099	4.96	18.9
	BROWN CT 11	45-R2.5	*	(5)	284,822.69	38,816	260,248	18,318	6.43	14.2
	BROWN CT GAS PIPELINE	45-R2.5	*	(5)	8,106,130.66	4,385,668	4,125,769	232,372	2.87	17.8
	HAEFLING UNITS 1, 2 AND 3	45-R2.5	*	(5)	518,704.54	88,960	455,680	55,109	10.62	8.3
	PADDY'S RUN GENERATOR 13	45-R2.5	*	(5)	1,995,101.02	695,267	1,399,589	75,845	3.80	18.5
	TOTAL ACCOUNT 342 - FUEL HOLDERS, PRODUCERS AND ACCESSORIES				22,747,816.41	8,652,455	15,232,750	840,013	3.69	18.1

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
343.00	PRIME MOVERS									
	TRIMBLE COUNTY CT 5	35-R1.5	*	(5)	31,137,756.05	10,133,882	22,560,762	1,259,343	4.04	17.9
	TRIMBLE COUNTY CT 6	35-R1.5	*	(5)	32,030,243.24	8,059,467	25,572,288	1,419,553	4.43	18.0
	TRIMBLE COUNTY CT 7	35-R1.5	*	(5)	23,223,115.61	6,218,174	18,166,097	926,898	3.99	19.6
	TRIMBLE COUNTY CT 8	35-R1.5	*	(5)	23,034,740.63	6,163,385	18,023,093	919,628	3.99	19.6
	TRIMBLE COUNTY CT 9	35-R1.5	*	(5)	22,902,195.54	5,896,000	18,151,305	925,844	4.04	19.6
	TRIMBLE COUNTY CT 10	35-R1.5	*	(5)	22,850,722.46	5,890,691	18,102,568	923,525	4.04	19.6
	BROWN CT 5	35-R1.5	*	(5)	14,666,936.33	4,448,405	10,951,878	635,708	4.33	17.2
343, cont.	BROWN CT 6	35-R1.5	*	(5)	34,600,149.28	7,991,509	28,338,648	1,813,591	5.24	15.6
	BROWN CT 7	35-R1.5	*	(5)	31,657,718.92	7,847,473	25,393,132	1,628,808	5.15	15.6
	BROWN CT 8	35-R1.5	*	(5)	26,710,989.99	10,068,236	17,978,303	1,455,318	5.45	12.4
	BROWN CT 9	35-R1.5	*	(5)	23,335,363.18	11,433,236	13,068,895	800,496	3.43	16.3
	BROWN CT 10	35-R1.5	*	(5)	20,074,765.96	9,663,038	11,415,466	700,567	3.49	16.3
	BROWN CT 11	35-R1.5	*	(5)	34,794,971.17	15,401,000	21,133,720	1,618,377	4.65	13.1
	PADDY'S RUN GENERATOR 13	35-R1.5	*	(5)	17,803,364.01	4,875,055	13,818,477	806,030	4.53	17.1
	TOTAL ACCOUNT 343 - PRIME MOVERS				358,823,032.37	114,089,551	262,674,632	15,833,686	4.41	16.6
344.00	GENERATORS									
	TRIMBLE COUNTY CT 5	55-S3	*	(5)	3,763,274.51	1,176,387	2,775,051	136,229	3.62	20.4
	TRIMBLE COUNTY CT 6	55-S3	*	(5)	3,757,946.57	1,174,917	2,770,927	136,027	3.62	20.4
	TRIMBLE COUNTY CT 7	55-S3	*	(5)	2,950,282.37	748,548	2,349,248	105,018	3.56	22.4
	TRIMBLE COUNTY CT 8	55-S3	*	(5)	2,937,930.22	745,414	2,339,413	104,578	3.56	22.4
	TRIMBLE COUNTY CT 9	55-S3	*	(5)	2,957,520.12	741,931	2,363,465	105,653	3.57	22.4
	TRIMBLE COUNTY CT 10	55-S3	*	(5)	2,954,148.53	741,085	2,360,771	105,533	3.57	22.4
	BROWN CT 5	55-S3	*	(5)	2,858,147.66	934,297	2,066,758	106,678	3.73	19.4
	BROWN CT 6	55-S3	*	(5)	3,712,619.52	1,492,911	2,405,339	138,397	3.73	17.4
	BROWN CT 7	55-S3	*	(5)	3,722,788.46	1,463,283	2,445,645	140,714	3.78	17.4
	BROWN CT 8	55-S3	*	(5)	4,953,960.72	2,809,555	2,392,104	178,782	3.61	13.4
	BROWN CT 9	55-S3	*	(5)	5,452,040.97	3,081,447	2,643,196	139,175	2.55	19.0
	BROWN CT 10	55-S3	*	(5)	4,944,422.71	2,624,840	2,566,804	134,599	2.72	19.1
	BROWN CT 11	55-S3	*	(5)	5,187,040.30	2,724,699	2,721,693	189,263	3.65	14.4
	HAEFLING UNITS 1, 2 AND 3	55-S3	*	(5)	4,023,002.37	3,504,167	719,985	92,815	2.31	7.8
	PADDY'S RUN GENERATOR 13	55-S3	*	(5)	5,185,636.11	1,792,632	3,652,286	188,553	3.64	19.4
	TOTAL ACCOUNT 344 - GENERATORS				59,360,761.14	25,756,113	36,572,685	2,002,014	3.37	18.3

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SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	TRIMBLE COUNTY CT 5	45-R3	*	(5)	1,693,975.04	513,697	1,264,977	64,303	3.80	19.7
	TRIMBLE COUNTY CT 6	45-R3	*	(5)	4,324,591.46	1,036,892	3,503,929	178,222	4.12	19.7
	TRIMBLE COUNTY CT 7	45-R3	*	(5)	3,148,439.35	792,088	2,513,773	116,323	3.69	21.6
	TRIMBLE COUNTY CT 8	45-R3	*	(5)	3,139,331.68	789,796	2,506,502	115,986	3.69	21.6
	TRIMBLE COUNTY CT 9	45-R3	*	(5)	3,234,031.47	804,392	2,591,341	119,912	3.71	21.6
	TRIMBLE COUNTY CT 10	45-R3	*	(5)	7,196,618.34	1,451,369	6,105,080	282,456	3.92	21.6
	BROWN CT 5	45-R3	*	(5)	2,277,020.49	662,990	1,727,882	92,383	4.06	18.7
	BROWN CT 6	45-R3	*	(5)	1,975,216.41	691,980	1,381,997	82,329	4.17	16.8
	BROWN CT 7	45-R3	*	(5)	1,935,781.98	675,547	1,357,024	80,891	4.18	16.8
	BROWN CT 8	45-R3	*	(5)	2,720,729.67	1,361,195	1,495,571	115,931	4.26	12.9
	BROWN CT 9	45-R3	*	(5)	4,205,847.29	1,987,226	2,428,914	133,961	3.19	18.1
	BROWN CT 10	45-R3	*	(5)	2,744,492.70	1,316,949	1,564,768	86,963	3.17	18.0
	BROWN CT 11	45-R3	*	(5)	1,863,053.15	778,412	1,177,794	84,727	4.55	13.9
	HAEFLING UNITS 1, 2 AND 3	45-R3	*	(5)	1,451,957.03	563,545	961,010	116,933	8.05	8.2
	PADDY'S RUN GENERATOR 13	45-R3	*	(5)	2,456,320.01	844,832	1,734,304	92,743	3.78	18.7
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT				44,367,406.07	14,270,910	32,314,866	1,764,063	3.98	18.3
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	TRIMBLE COUNTY CT 5	35-R2	*	(5)	28,963.63	8,377	22,035	1,171	4.04	18.8
	TRIMBLE COUNTY CT 7	35-R2	*	(5)	8,888.93	2,318	7,015	353	3.97	19.9
	TRIMBLE COUNTY CT 8	35-R2	*	(5)	8,861.01	2,310	6,994	352	3.97	19.9
	TRIMBLE COUNTY CT 9	35-R2	*	(5)	9,113.52	2,350	7,219	363	3.98	19.9
	TRIMBLE COUNTY CT 10	35-R2	*	(5)	41,868.51	4,157	39,805	1,922	4.59	20.7
	BROWN CT 5	35-R2	*	(5)	2,139,352.61	749,750	1,496,570	86,757	4.06	17.3
346, cont.	BROWN CT 6	35-R2	*	(5)	53,748.85	17,904	38,532	2,404	4.47	16.0
	BROWN CT 7	35-R2	*	(5)	35,647.39	13,487	23,943	1,515	4.25	15.8
	BROWN CT 8	35-R2	*	(5)	285,932.33	133,886	166,343	13,435	4.70	12.4
	BROWN CT 9	35-R2	*	(5)	760,255.37	435,836	362,432	22,729	2.99	15.9
	BROWN CT 10	35-R2	*	(5)	274,390.87	136,467	151,643	9,323	3.40	16.3
	BROWN CT 11	35-R2	*	(5)	590,562.82	219,404	400,687	29,785	5.04	13.5
	HAEFLING UNITS 1, 2 AND 3	35-R2	*	(5)	35,805.20	34,289	3,306	597	1.67	5.5
	PADDY'S RUN GENERATOR 13	35-R2	*	(5)	1,089,550.03	384,938	759,090	44,055	4.04	17.2
	TOTAL ACCOUNT 346 - MISCELLANEOUS POWER PLANT EQUIPMENT				5,362,941.07	2,145,473	3,485,614	214,761	4.00	16.2
	TOTAL OTHER PRODUCTION PLANT				**526,856,779.58**	**178,011,802**	**375,178,989**	**22,008,824**	**4.18**	

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	TRANSMISSION PLANT								
350.10	LAND RIGHTS	60-R3	0	23,413,728.55	15,953,928	7,459,801	225,538	0.96	33.1
352.10	STRUCTURES AND IMPROVEMENTS	65-S2.5	(25)	17,020,058.51	4,850,267	16,424,806	298,018	1.75	55.1
352.20	STRUCTURES AND IMPROVEMENTS - SYS. CONTROL/COM	60-R3	(25)	1,220,542.62	860,225	665,453	19,271	1.58	34.5
353.10	STATION EQUIPMENT	60-R2	(10)	191,753,788.17	67,092,664	143,836,503	3,211,159	1.67	44.8
353.20	STATION EQUIPMENT - SYS. CONTROL/COM	35-R2.5	(10)	14,668,403.51	16,135,244	0	0	-	-
354.00	TOWERS AND FIXTURES	70-R4	(25)	95,353,356.62	48,758,751	70,432,945	1,300,626	1.36	54.2
355.00	POLES AND FIXTURES	55-R2	(55)	148,658,780.48	68,401,548	162,019,562	3,485,089	2.34	46.5
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R3	(50)	160,446,879.27	109,283,433	131,386,886	3,105,267	1.94	42.3
357.00	UNDERGROUND CONDUIT	45-R4	0	448,760.26	187,418	261,342	10,209	2.27	25.6
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-R3	0	1,161,549.29	918,039	243,510	11,420	0.98	21.3
	TOTAL TRANSMISSION PLANT			**654,145,847.28**	**332,441,517**	**532,730,808**	**11,666,597**	**1.78**	
	DISTRIBUTION PLANT								
360.10	LAND RIGHTS	65-R4	0	2,039,033.29	1,485,249	553,784	11,896	0.58	46.6
361.00	STRUCTURES AND IMPROVEMENTS	60-R2.5	(20)	7,658,288.09	1,787,771	7,402,175	153,285	2.00	48.3
362.00	STATION EQUIPMENT	54-R2	(20)	141,200,430.90	40,173,683	129,266,834	3,198,522	2.27	40.4
364.00	POLES, TOWERS, AND FIXTURES	50-R1	(45)	287,791,923.15	133,160,672	284,137,617	6,719,281	2.33	42.3
365.00	OVERHEAD CONDUCTORS AND DEVICES	48-R1.5	(60)	276,285,758.81	108,982,197	333,075,017	8,911,891	3.23	37.4
366.00	UNDERGROUND CONDUIT	50-R4	(5)	1,861,963.15	653,383	1,301,678	50,337	2.70	25.9
367.00	UNDERGROUND CONDUCTORS AND DEVICES	44-R2	(10)	140,620,009.32	28,891,798	125,790,212	3,333,408	2.37	37.7
368.00	LINE TRANSFORMERS	43-R2	(15)	286,070,399.06	117,730,753	211,250,206	7,018,693	2.45	30.1
369.00	SERVICES	43-R1.5	(30)	89,050,180.39	57,697,779	58,067,456	1,811,200	2.03	32.1
370.00	METERS	39-R2	0	70,049,355.34	32,484,596	37,564,759	1,603,713	2.29	23.4
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	25-O1	(10)	18,253,214.45	17,404,873	2,673,663	148,124	0.81	18.1
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	28-S0	(10)	81,534,875.55	20,703,034	68,985,329	3,261,361	4.00	21.2
	TOTAL DISTRIBUTION PLANT			**1,402,415,431.50**	**561,155,788**	**1,260,068,730**	**36,221,711**	**2.58**	

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERAL PLANT								
390.10	STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY	55-S0	(10)	47,011,269.52	9,650,596	42,061,800	945,113	2.01	44.5
390.20	STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY	30-R1	(10)	531,973.44	413,480	171,691	9,139	1.72	18.8
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	7,513,787.56	4,161,871	3,351,917	335,131	4.46	10.0
391.20	NON PC COMPUTER EQUIPMENT	5-SQ	0	17,256,012.35	6,803,953	10,452,059	3,723,700	21.58	2.8
391.31	PERSONAL COMPUTERS	4-SQ	0	6,398,371.65	4,572,023	1,826,349	571,269	8.93	3.2
392.10	TRANSPORTATION EQUIPMENT - CARS AND LIGHT TRUCKS	7-L2.5	0	1,865,090.97	1,578,423	286,668	45,497	2.44	6.3
392.30	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS AND OTHER	14-S1.5	0	14,101,987.63	13,160,795	941,193	76,623	0.54	12.3
393.00	STORES EQUIPMENT	25-SQ	0	551,794.27	164,539	387,255	27,960	5.07	13.9
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	7,648,755.44	1,767,311	5,881,444	326,703	4.27	18.0
396.30	POWER OPERATED EQUIPMENT - LARGE MACHINERY	12-L1.5	0	1,174,225.44	139,927	1,034,298	104,334	8.89	9.9
397.10	COMMUNICATION EQUIPMENT - GENERAL ASSETS	10-SQ	0	10,171,295.90	5,248,935	4,922,361	579,495	5.70	8.5
397.20	COMMUNICATION EQUIPMENT - SPECIFIC ASSETS	25-S1	0	19,915,035.90	5,655,027	14,260,009	746,086	3.75	19.1
397.30	COMMUNICATION EQUIPMENT - FULLY ACCRUED	FULLY ACCRUED	0	786,233.20	786,233	0	0	-	-
	TOTAL GENERAL PLANT			**134,925,833.27**	**54,103,113**	**85,577,044**	**7,491,050**	**5.55**	
	TOTAL DEPRECIABLE PLANT			**6,365,236,955.68**	**2,412,555,355**	**5,047,541,827**	**187,147,698**	**2.94**	
	NONDEPRECIABLE PLANT								
301.00	ORGANIZATION			44,455.58					
310.20	LAND			10,881,103.86					
340.20	LAND			118,514.41					
350.20	LAND			2,199,383.04					
360.20	LAND			3,271,807.48					
389.20	LAND			2,567,847.40					
	TOTAL NONDEPRECIABLE PLANT			**19,083,111.77**					
	TOTAL ELECTRIC PLANT			**6,384,320,067.45**	**2,412,555,355**	**5,047,541,827**	**187,147,698**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 14

Responding Witness: Shannon L. Charnas / John J. Spanos

Q-14. Refer to the response to Item 50.e. of Staff's Second Request, which does not contain the requested information. Under Generally Accepted Accounting Principles, financial statements must report asset removal costs recovered through depreciation which are not Asset Retirement Obligations ("ARO") as a regulatory liability.

a. Provide the total amount of asset removal costs KU reported as a regulatory liability in its financial statements as of December 31, 2011.

b. Provide the total amount of AROs KU reported in its financial statements as of December 31, 2011

c. Provide the regulatory liability reported as of December 31, 2011 that was accrued on the Tyrone units. Provide the workpapers demonstrating how the amounts were determined.

d. Provide the amount of AROs reported as of December 31, 2011 that were accrued on the Tyrone units. Provide the workpapers demonstrating how the amounts were determined.

e. Provide the regulatory liability reported as of December 31, 2011 that was accrued on the Green River units. Provide the workpapers demonstrating how the amounts were determined.

f. Provide the amount of AROs reported as of December 31, 2011 that were accrued on the Green River Units. Provide the workpapers demonstrating how the amounts were determined.

A-14. a. The total amount of asset removal costs KU reported as a regulatory liability as of December 31, 2011, was $365,054,959.

b. The total ARO liability KU reported as of December 31, 2011 was $61,379,032.

c. Per Title 18, Subchapter C – Accounts, Federal Power Act, Part 101 – Uniform System of Accounts prescribed for Public Utilities, account 108, accumulated provision for depreciation of utility plant, shall be regarded and treated as a single composite provision for depreciation, but shall be segregated by functional classification. Further detail by plant account is not required, but is calculated for ease of reporting. This calculation is simply an allocation of the total cost of removal and salvage reserve performed by the fixed asset system. The total amount of regulatory liability as of December 31, 2011 allocated as mentioned above for the Tyrone units was $4,280,955. See attached for the work paper.

d. The total ARO liability for the Tyrone units as of December 31, 2011 was $2,757,857. See attached for the work paper.

e. Per Title 18, Subchapter C – Accounts, Federal Power Act, Part 101 – Uniform System of Accounts prescribed for Public Utilities, account 108, accumulated provision for depreciation of utility plant, shall be regarded and treated as a single composite provision for depreciation, but shall be segregated by functional classification. Further detail by plant account is not required, but is calculated for ease of reporting. This calculation is simply an allocation of the total cost of removal and salvage reserve performed by the fixed asset system. The total amount of regulatory liability as of December 31, 2011 allocated as mentioned above for the Green River units was $7,873,835. See attached for the work paper.

f. The total ARO liability for the Green River units as of December 31, 2011 was $8,821,912. See attached for the work paper.

KENTUCKY UTILITIES
REGULATORY LIABILITY FOR GREEN RIVER AND TYRONE
DECEMBER 31, 2011

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	KU-131100-GR 1-2 Structures and Improvements	$	590,379.33
SALVAGE	KU-131100-GR 1-2 Structures and Improvements		(2,173.41)
COST OF REMOVAL	KU-131200-GR 1-2 Boiler Plant Equipment		1,767,681.95
SALVAGE	KU-131200-GR 1-2 Boiler Plant Equipment		(123,763.25)
COST OF REMOVAL	KU-131500-GR 1&2 Accessory Electric		84,866.00
SALVAGE	KU-131500-GR 1&2 Accessory Electric		-
COST OF REMOVAL	KU-131600-GR 1&2 Miscellaneous Power Plant		30,114.18
SALVAGE	KU-131600-GR 1&2 Miscellaneous Power Plant		(76.23)
	TOTAL GREEN RIVER 1&2	$	2,347,028.57
COST OF REMOVAL	KU-131100-GR 3 Structures and Improvement	$	355,276.89
SALVAGE	KU-131100-GR 3 Structures and Improvement		(2,959.65)
COST OF REMOVAL	KU-131200-GR 3 Boiler		1,018,486.27
SALVAGE	KU-131200-GR 3 Boiler		(220,639.04)
COST OF REMOVAL	KU-131200-GR 3 Boil ECR 2006		1,030.21
SALVAGE	KU-131200-GR 3 Boil ECR 2006		(128.22)

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	KU-131400-GR 3 Turbogenerator Unit		424,798.79
SALVAGE	KU-131400-GR 3 Turbogenerator Unit		(66,889.88)
COST OF REMOVAL	KU-131500-GR 3 Accessory Electric		(143,369.50)
SALVAGE	KU-131500-GR 3 Accessory Electric		80,636.85
COST OF REMOVAL	KU-131600-GR 3 Misc Power Plant Equipement		9,670.32
SALVAGE	KU-131600-GR 3 Misc Power Plant Equipement		(161.01)
	TOTAL GREEN RIVER 3	$	1,455,752.03
COST OF REMOVAL	KU-131100-GR 4 Structures and Improvement	$	426,439.55
SALVAGE	KU-131100-GR 4 Structures and Improvement		(7,739.28)
COST OF REMOVAL	KU-131200-GR 4 Boiler		2,885,534.88
SALVAGE	KU-131200-GR 4 Boiler		(726,767.56)
COST OF REMOVAL	KU-131200-GR 4 Boil ECR 2006		1,852.53
SALVAGE	KU-131200-GR 4 Boil ECR 2006		(182.94)
COST OF REMOVAL	KU-131400-GR 4 Turbogenerator Unit		1,550,293.28
SALVAGE	KU-131400-GR 4 Turbogenerator Unit		(341,166.52)
COST OF REMOVAL	KU-131500-GR 4 Accessory Electric		109,504.72
SALVAGE	KU-131500-GR 4 Accessory Electric		-

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	KU-131600-GR 4 Misc Power Plant Equipment		177,021.99
SALVAGE	KU-131600-GR 4 Misc Power Plant Equipment		(3,736.59)
	TOTAL GREEN RIVER 4	$	4,071,054.06
	TOTAL GREEN RIVER	$	7,873,834.66
COST OF REMOVAL	KU-131100-TY 1&2 Structures and Improvement	$	111,768.73
SALVAGE	KU-131100-TY 1&2 Structures and Improvement		-
COST OF REMOVAL	KU-131200-TY 1&2 Boiler		758,046.46
SALVAGE	KU-131200-TY 1&2 Boiler		-
COST OF REMOVAL	KU-131400-TY 1&2 Turbogenerator		342,019.57
SALVAGE	KU-131400-TY 1&2 Turbogenerator		-
COST OF REMOVAL	KU-131500-TY 1&2 Accessory Electric		177,131.22
SALVAGE	KU-131500-TY 1&2 Accessory Electric		-
COST OF REMOVAL	KU-131600-TY 1&2 Miscelaneous Power Plant		10,247.86
SALVAGE	KU-131600-TY 1&2 Miscelaneous Power Plant		-
	TOTAL TYRONE 1&2	$	1,399,213.84
COST OF REMOVAL	KU-131100-TY 3 Structures and Improvement	$	1,059,951.02
SALVAGE	KU-131100-TY 3 Structures and Improvement		(6,214.77)
COST OF REMOVAL	KU-131200-TY 3 Boiler		1,582,672.45
SALVAGE	KU-131200-TY 3 Boiler		(265,244.75)

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	KU-131200-TY 3 Boil ECR 2006		535.18
SALVAGE	KU-131200-TY 3 Boil ECR 2006		(21.78)
COST OF REMOVAL	KU-131400-TY 3 Turbogenerator Unit		424,106.60
SALVAGE	KU-131400-TY 3 Turbogenerator Unit		(61,877.58)
COST OF REMOVAL	KU-131500-TY 3 Accessory Electric		66,404.46
SALVAGE	KU-131500-TY 3 Accessory Electric		23,456.37
COST OF REMOVAL	KU-131600-TY 3 Misc Power Plant Equipment		58,571.61
SALVAGE	KU-131600-TY 3 Misc Power Plant Equipment		(597.89)
		TOTAL TYRONE 3	$ 2,881,740.92
		TOTAL TYRONE	$ 4,280,954.76

KENTUCKY UTILITIES
ASSET RETIREMENT OBLIGATION LIABILITY
GREEN RIVER AND TYRONE
DECEMBER 31, 2011

ARO DESCRIPTION		BALANCE 12/31/2011
Green River Ash Pond	$	6,234,927.86
Green River Chemical Storage		662.49
Green River Coal Storage		208,849.75
Green River Generating Wells		107,155.78
Green River Oil Storage		940.45
Green River Unit 1-Asbestos		567,002.81
Green River Unit 2-Asbestos		521,029.69
Green River Unit 3-Asbestos		514,731.83
Green River Unit 4-Asbestos		666,611.44
TOTAL GREEN RIVER	$	8,821,912.10
Tyrone Ash Pond	$	1,020,260.97
Tyrone Chemical Storage		430.07
Tyrone Coal Storage		69,616.83
Tyrone Generating Wells		35,718.34
Tyrone Oil Storage		10,165.10
Tyrone Unit 1 (Retired)-Asbestos		491,606.75
Tyrone Unit 2 (Retired)-Asbestos		483,944.64
Tyrone Unit 3-Asbestos		646,114.15
TOTAL TYRONE	$	2,757,856.85

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 15

Responding Witness: Lonnie E. Bellar

Q-15. Refer to KU's response to Item 72.b. of Staff's Second Request. Given that the response states that "physical curtailments would generally be necessary during times of high usage which usually results in relatively high market peak prices," explain whether it is still KU's position that its proposed curtailable service rider credits are reasonable.

A-15. KU believes its proposed Curtailable Service Rider (CSR) credits are reasonable. KPSC 2-72(b) refers to the proposed CSR10 tariff which for a transmission voltage served customer would provide a credit of $2.75 per kVA-month. If you assume a customer has a unity (kW=kVA) power factor and the company physically interrupts the customer for the maximum of 100 hours in a year, the effective credit to the customer will be $330/MWh.[1] The maximum average of the 100 highest priced hours in the PJM and MISO markets on a rolling one year period from 2008 to August 2012 was $227/MWh.[2] While this simple example for a CSR10 customer does not consider the incremental value of the 275 hours of buy-through interruption and the benefit of being able to effect the physical interruption in 10 minutes, from an energy perspective the difference in the maximum market price and the calculated value demonstrates the reasonableness of the Companies' proposal.

[1] 2.75 $/kVA-month x 1,000 kVA/MW X 12 month/year = $33,000/MW-year => ($33,000/MW-year)/(100 hours/year) = $330/MWh.

[2] This value is derived by determining the maximum hourly price from the LG&E/KU interface with MISO (LGEE) and PJM (South Import) and calculating the described average.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 16

Responding Witness: Robert M. Conroy

Q-16. Refer to KU's response to Item 73 of Staff's Second Request. Ordering paragraph 5 of the July 15, 1999 Order in Case Nos. 94-461-A, 94-461-B, 94-461-C, and 96-523[3] stated that "KU shall immediately discontinue its practice of restating its total system line losses using the retail line loss factor. When determining the amount of system losses to include on the Sales Schedule of its monthly FAC filings, KU shall use the overall system losses based on 12 months to date information." In addition, the August 30, 1999 Order on rehearing states that 807 KAR 5:056 "requires the elimination of 'total system losses' in the determination of an FAC's sales component." Given the language in these orders, explain why KU has been using losses related to the Kentucky jurisdiction portion of its electric system since the time of the Orders.

A-16. KU has been unable to determine why Kentucky jurisdiction losses have been used in the monthly FAC calculations. Searches performed on FAC filings and associated support and files show in August 1999, KU discontinued its then practice of restating its total line losses using the retail line loss factor, but do not disclose any insight into the reasons for then using the total Kentucky jurisdiction losses at some later date in the monthly filings. Currently KU knows that the values used are Kentucky jurisdictional losses. All management personnel involved with the FAC at the time of the 1999 Order are no longer with the Company.

[3] The fuel adjustment clause review cases covered the period from November 1, 1994 through October 31, 1996 (Ky. PSC July 15, 1999).

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 17

Responding Witness: Robert M. Conroy

Q-17. Refer to the "Copy of KUBillDeterminants-PSC_Q75_Revised" Excel spreadsheet included in the response to Item 75 of Staff's Second Request, file 8, tab "Conroy Exhibit R5 pgs 1-11."

a. For the rate class PS-Secondary, the cells in the "Calculated Revenue at Proposed Rates" column for "Power factor adjustment charges" and "Prorated corrected and demand charges" are formulas which provide for an increase at proposed rates. For the rate class PS-Primary, the cells in the "Calculated Revenue at Proposed Rates" column for "Power factor adjustment charges" and "Prorated corrected and demand charges" do not provide for an increase at proposed rates but rather use the amounts at present rates. Explain why the proposed revenues for these items are calculated differently between the two rate schedules.

b. Refer to the Time of Day Secondary Service Rate TODS, Adjustment to Reflect Rate Switching to TODS, rows 265 through 267 under column C. Explain why it is correct for 115,245 kVA to be used for each base, intermediate, and peak demand adjustments rather than the kVA for the three adjustments totaling 115,245.

c. Refer to the Time of Day Primary Service Rate TODP, Adjustment to Reflect Rate Switching to TODP, rows 310 through 312 under column C. Explain why it is correct for 254,513 kVA to be used for each base, intermediate, and peak demand adjustments rather than the kVA for the three adjustments totaling 254,513.

A-17. a. The proposed revenues for the items in Rate PS-P should have been calculated in the same manner as was done for Rate PS-S. A revised Conroy Exhibit R-5, page 5 is attached.

b. Rate TOD-S demand rate design uses a "layered" rate design. The intermediate period is inclusive of the peak period and the base period is inclusive of the intermediate. Therefore, if a customer's highest demand reading for the billing period occurs during the peak period, then the customer pays the peak rate, the intermediate rate and base rate on the same demand reading. The purpose of this type of rate design is to provide an economic incentive to shift load from the peak period, since doing so results in a lower demand charge. For the purposes of the rate switching adjustment, the customers that moved to Rate TOD-S had not been on time-differentiated demand rates. KU made a reasonable assumption that the actual (or calculated in the case of GS customers) demands billed occurred during the peak period, which results in all three demand rates being charged to the total demands.

c. See the response to part b. One customer moved from Rate RTS to Rate TOD-P, and that customer's billed demands on Rate RTS indicated that the peak demands occurred during the peak period, and therefore all three demand rates were charged on that demand.

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Customer Bills	Demand kW	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
POWER SERVICE RATE PS-Primary							
Basic Service Charges	3,743			$ 90.00	$ 336,870	$ 125.00	$ 467,875
All Energy			802,429,053	$ 0.03300	$ 26,480,159	$ 0.03349	$ 26,873,349
Summer Demand		845,807		$ 13.72	$ 11,604,476	$ 14.75	$ 12,475,657
Winter Demand		985,114		$ 11.45	$ 11,279,551	$ 12.73	$ 12,540,497
Minimum kW and charges		35,640			$ 1,104,290		$ 1,207,178
Redundant Capacity Rider		51,285		$ 0.68	$ 34,874	$ 0.99	$ 50,772
Power factor adjustment charges					$ 429,197		$ 469,186
Prorated and corrected basic service charge billings					$ (1,126)		$ (1,564)
Prorated and corrected energy billings					$ 5,659		$ 5,743
Prorated and corrected demand charges					$ (49,401)		$ (54,004)
			Total Calculated at Base Rates		**$ 51,224,549**		**$ 54,034,688**
			Correction Factor		1.0000000000		1.0000000000
			Total After Application of Correction Factor		**$ 51,224,549**		**$ 54,034,688**
Fuel Clause Billings - proforma for rollin					$ 759,739		$ 759,739
Adjustment to Reflect Year-End Customers					$ 171,787		$ 181,211
Adjustment to Reflect Rate Switching to Rate PS-Primary					$ 335,827		
Customer-months Moving to Rate	11					$ 125.00	$ 1,375
Energy Use Moving to Rate			5,497,600			$ 0.03349	$ 184,115
Summer Demand for Customers Moving to Rate		6,690				$ 14.75	$ 98,678
Winter Demand for Customers Moving to Rate		5,452				$ 12.73	$ 69,404
Adjustment to Reflect Rate Switching From Rate PS-Primary					$ (5,722,036)		
Customer-months Moving to Rate	(210)					$ 125.00	$ (26,250)
Energy Use Moving to Rate			(84,756,887)			$ 0.03349	$ (2,838,508)
Summer Demand for Customers Moving From Rate		(136,239)				$ 14.75	$ (2,009,525)
Winter Demand for Customers Moving From Rate		(92,754)				$ 12.73	$ (1,180,758)
Adjustment to Reflect Removal of Base ECR Revenues					$ (6,225,132)		$ (201,402)
Adjustment to Reflect Elimination of ECR Plans					$ 6,023,730		$ -
Total Base Revenues Net of ECR					**$ 46,568,464**		**$ 49,072,765**
ECR Base Revenues					$ 201,402		$ 201,402
ECR Billings - proforma for rollin					$ 445,709		$ 445,709
Total Base Revenues Inclusive of ECR					**$ 47,215,575**		**$ 49,719,876**
Proposed Increase							**2,504,301**
	Percentage Increase						5.30%

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 18

Responding Witness: Robert M. Conroy

Q-18. Refer to the response to Item 78 of Staff's Second Request. Provide a copy of the two contracts to which the response refers.

A-18. See attached. Certain information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

321
Route No. 2900
Acct. No. [redacted]

CONFIDENTIAL INFORMATION REDACTED

CONTRACT FOR EXPERIMENTAL LOAD REDUCTION INCENTIVE RIDER STAND-BY GENERATION

This Supplemental Contract for Stand-by Generation made and entered into this ____ day of ____________, 20 02 by and between KENTUCKY UTILITIES COMPANY, (hereinafter called "Company") and Toyota Motor Manufacturing, Kentucky, Inc Georgetown (Town) Kentucky (State), (hereinafter called "Customer").

Company's rates, terms and conditions for the provision of electric service to Customer, and Customer's obligations, rights and responsibilities to Company for the supply of electric service are specified in and determined by Rate Schedule LCI-TOD and other applicable schedules in Company's Tariff on file with and approved by the Kentucky Public Service Commission and the Contract For Electric Service dated ____________ ("Electric Service Contract").

This LRI Contract is supplemental to and by agreement made a part of the Electric Service Contract for the purpose of providing Company the right to request Customer to generate electricity in exchange for bill credits by Company in accordance with the LRI Electric Rate Schedule on file with and approved by the Kentucky Public Service Commission.

WITNESSETH: For an initial period not to end before ____________ and subject to Company's General Rules and Regulations or Terms and Conditions, Customer possesses stand-by generation of 3000 KW with the primary fuel source being fuel oil , with customer ensuring that an adequate fuel supply exists.

TERM:

The minimum term of Stand-By Generation Rider shall be for (1) one year. Either the Customer or the Company may terminate this contract by giving at least (6) six months advance written notice.

Company will (1) Notify Customer, by 12 noon on a day ahead basis, of its need for customer to operate stand-by generation (2) Company will offer Customer an incentive based upon generated KWH (3) Customer will either a) Accept or b) Decline. If Customer accepts the offered price per KWH, Customer is obligated to operate and to sustain stand-by generation (The total hours of generation in any 12-month period shall not exceed 300 hours). The stand-by generation output will be metered by Company with payment provided through a bill credit on the Customer's standard service billing.

OPERATIONS:

Customer will install metering quality potential transformers "PT's" and current transformers "CT's" and will install wiring to the nearest possible location as to the satisfaction of the Company. Company will install, at its expense, a metering apparatus which will be used to measure the KWH output of the Stand-by generator(s).

Customer's stand-by generation shall *not* be operated in parallel with Company's system such that all affected Customer-owned circuits are isolated from Company's system.

Customer may allow Company to install remote control equipment that will permit Company to start stand-by generation and to isolate Customer's circuits.

Stand-by generation voltage will be supplied as three phase, 60 cycle, alternating current of nominal 13,200 volts.

Where rate schedule has optional clause and/or service is metered or billed at other than delivered voltage, and/or minimum other than standard minimum is required, or additional description is required, give explanation:

TARIFF PROVISIONS

It is mutually agreed that Company's general Rules and Regulations or Terms and Conditions and rate(s) applicable to the service supplied hereunder, as from time to time approved by and on file with the Public Service Commission of Kentucky, are made parts of this Contract as fully as written herein.

IN WITNESS WHEREOF, the parties hereto have caused this Contract to be executed by their duly authorized representatives this day and year shown above.

KENTUCKY UTILITIES COMPANY

By ____________

Account Manager
Official Capacity

Attest: Charles McKenna

Toyota Motor Manufacturing Kentucky, Inc. Customer

By Pete Gritton

Vice President Administration
Type or Print Name of Signer

PETE GRITTON
Official Capacity

Attest: ____________

321
Route No. 2900
Acct. No. [redacted]

CONFIDENTIAL INFORMATION REDACTED

CONTRACT FOR EXPERIMENTAL LOAD REDUCTION INCENTIVE RIDER
STAND-BY GENERATION

This Supplemental Contract for Stand-by Generation made and entered into this ____ day of ______________, 20 02 by and between KENTUCKY UTILITIES COMPANY, (hereinafter called "Company") and Toyota Motor Manufacturing, Kentucky, Inc Georgetown (Town) Kentucky (State), (hereinafter called "Customer").

Company's rates, terms and conditions for the provision of electric service to Customer, and Customer's obligations, rights and responsibilities to Company for the supply of electric service are specified in and determined by Rate Schedule LCI-TOD and other applicable schedules in Company's Tariff on file with and approved by the Kentucky Public Service Commission and the Contract For Electric Service dated ______________ ("Electric Service Contract").

This LRI Contract is supplemental to and by agreement made a part of the Electric Service Contract for the purpose of providing Company the right to request Customer to generate electricity in exchange for bill credits by Company in accordance with the LRI Electric Rate Schedule on file with and approved by the Kentucky Public Service Commission.

WITNESSETH: For an initial period not to end before ______________ and subject to Company's General Rules and Regulations or Terms and Conditions, Customer possesses stand-by generation of 3000 KW with the primary fuel source being fuel oil, with customer ensuring that an adequate fuel supply exists.

TERM:

The minimum term of Stand-By Generation Rider shall be for (1) one year. Either the Customer or the Company may terminate this contract by giving at least (6) six months advance written notice.

Company will (1) Notify Customer, by 12 noon on a day ahead basis, of its need for customer to operate stand-by generation (2) Company will offer Customer an incentive based upon generated KWH (3) Customer will either a) Accept or b) Decline. If Customer accepts the offered price per KWH, Customer is **obligated** to operate and to sustain stand-by generation (The total hours of generation in any 12-month period shall not exceed 300 hours). The stand-by generation output will be metered by Company with payment provided through a bill credit on the Customer's standard service billing.

OPERATIONS:

Customer will install metering quality potential transformers "PT's" and current transformers "CT's" and will install wiring to the nearest possible location as to the satisfaction of the Company. Company will install, at its expense, a metering apparatus which will be used to measure the KWH output of the Stand-by generator(s).

Customer's stand-by generation shall *not* be operated in parallel with Company's system such that all affected Customer-owned circuits are isolated from Company's system.

Customer may allow Company to install remote control equipment that will permit Company to start stand-by generation and to isolate Customer's circuits.

Stand-by generation voltage will be supplied as three phase, 60 cycle, alternating current of nominal 13,200 volts.

Where rate schedule has optional clause and/or service is metered or billed at other than delivered voltage, and/or minimum other than standard minimum is required, or additional description is required, give explanation:

____

TARIFF PROVISIONS

It is mutually agreed that Company's general Rules and Regulations or Terms and Conditions and rate(s) applicable to the service supplied hereunder, as from time to time approved by and on file with the Public Service Commission of Kentucky, are made parts of this Contract as fully as written herein.

IN WITNESS WHEREOF, the parties hereto have caused this Contract to be executed by their duly authorized representatives this day and year shown above.

KENTUCKY UTILITIES COMPANY	Toyota Motor Manufacturing Kentucky, Inc. Customer
By [signature]	By Pete Gritton
Account Manager (Official Capacity)	Vice President Administration (Official Capacity)
Attest: Charles McHarma	PETE GRITTON (Type or Print Name of Signer)
	Attest: Jeff Klahr.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 19

Responding Witness: Robert M. Conroy

Q-19. Refer to the response to Item 79 of Staff's Second Request, which states that the Supplemental/Standby Service charge had previously been adjusted based on the proposed changes to demand charges but that, in this case, KU used cost-based charges. Explain the reason for the change.

A-19. KU's previous Supplemental/Stand-by rates were developed by applying a percentage increase that approximately reflected the increase in the large power schedule under which a supplemental or standby customer would take service.

KU currently does not serve any customers under this rider. Therefore, the Company concluded that it would be more appropriate to adjust the rate to reflect the full cost of providing service without resulting in billing increases to any customers. In other words, at this point in time, the rate can be adjusted without a customer experiencing a large billing increase; therefore, the cost of service principle of gradualism should not be followed, in this instance, because no customers would be affected by the change.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 20

Responding Witness: Robert M. Conroy

Q-20. Refer to the response to Item 80 of Staff's Second Request. Explain what KU perceives to be the reason(s) for the "lack of customer response" to the Real Time Pricing tariff.

A-20. Real Time Pricing was presented to all eligible customers. Most of those customers discarded any interest immediately, although there were a few customers who requested additional information before rejecting the use of Rate RTP.

The negative response revolved around the need to monitor and control loads to realize any savings. Administratively for the customer, Rate RTP required more time and an expertise with which the customer felt uncomfortable. In addition, the savings which the customer could achieve from the reduction in billing for electric service would not off-set the other anticipated costs for the customer to comply with Rate RTP.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 21

Responding Witness: Chris Hermann / Cheryl E. Bruner

Q-21. Refer to the response to Item 81 of Staff's Second Request, which states that KU included information on the Low Emission Vehicle ("LEV") tariff in bill inserts in April 2011 and has information on its web site. The response also states that the tariff has two new customers since the filing of the Conroy Testimony. Explain whether KU is aware of how the two customers were made aware of the existence of the tariff.

A-21. In both cases, the Customer explained to the Company that the dealership selling the vehicle suggested that the Customer contact their utility for a special electric rate. The Customers inquired with the Company about such a rate.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 22

Responding Witness: Robert M. Conroy

Q-22. Refer to the response to Item 82 of Staff's Second Request. Explain whether KU experienced a significantly greater level of rate switching in the test year than in the past. The response should include the level of switching experienced in the five prior calendar years (2006-2010) and discuss why such an adjustment is proposed in this case when KU proposed no similar adjustment in its two prior rate cases.

A-22. The level of rate switching experienced is only available beginning in April 2009 with the implementation date of KU's Customer Care System ("CCS"). The enhanced database and query opportunities available with CCS allow KU to track customer movements to a degree not previously possible. See the table below for the number of customers who moved from one rate to another rate by month for the period April 2009 through March 2011. KU believes that as customers become increasingly aware of the rate options available, they are initiating rate switching when such a move results in economic benefit.

In Case No. 2008-00251 KU did not include a proposed adjustment for rate switching because no major customers were identified as having switched rates. KU proposed a revenue adjustment of ($172,038.08) due to customer rate switching in Case No. 2009-00548.[4] Prior to KU's implementation of CCS, the ability to track customers by rate schedule, and also to query the database for such information, was extremely limited. For this reason, earlier rate cases only proposed revenue adjustments for rate switching when large customers made such a switch, which was an unusual occurrence.

[4] See Rives Exhibit 1, Schedule 1-13 and Conroy Exhibit 1.

`

Month	Number of Customers
APR 2009	69
MAY 2009	66
JUN 2009	98
JUL 2009	145
AUG 2009	152
SEP 2009	175
OCT 2009	210
NOV 2009	209
DEC 2009	515
JAN 2010	274
FEB 2010	129
MAR 2010	176
APR 2010	181
MAY 2010	187
JUN 2010	213
JUL 2010	868
AUG 2010	1,233
SEP 2010	441
OCT 2010	656
NOV 2010	397
DEC 2010	260
JAN 2011	199
FEB 2011	166
MAR 2011	224

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 23

Responding Witness: Robert M. Conroy

Q-23. Refer to the response to Item 84 of Staff's Second Request.

a. Refer to the response to Item 84.a. and the revised Exhibit Conroy P5 Excel spread sheet, page 7 of 8. Explain why cell C260, Actual Number of Customers for the 13-Month Period for Residential Customers including VFD and former RRP, is not calculated by the sum of cells B5 through B8, as opposed to cell F260 being the sum of cells B5 through B8. It appears that cell C260 should be 5,466,464 and that cell F260 should be the sum of cells C260, D260, and E260, for a total of 5,466,549 customers after rate switching. Likewise, explain why the same would not be true for the other rate classes shown. If a correction is necessary, provide a revised Exhibit Conroy P5 and revisions of all exhibits that would be affected by this change.

b. Refer to the response to Item 84.b. and the revised Exhibit Conroy P5 Excel spread sheet, page 7 of 8. Explain why cell H260, Actual Energy Delivered for the 13-Month Period for Residential Customers including VFD and former RRP, is not calculated by the sum of cells F5 through F8, as opposed to cell K260 being the sum of cells F5 through F8. It appears that cell H260 should be 6,476,721,487 and that cell K260 should be the sum of cells H260, I260, and J260, for a total of 6,476,267,049 energy usage to reflect rate switching. Likewise, explain why the same would not be true for the other rate classes shown. If a correction is necessary, provide a revised Exhibit Conroy P5 and revisions of all exhibits that would be affected by this change.

A-23. a. Cells B5 through B8 already include the impact of rate switching. The formulae for these cells use lookup functions to count the number of customers on the rates for each month of the 13-month period, and then add or subtract the number of customer-months reflecting the rate switching adjustment, as provided in cells V5 (for customers leaving the rate) and W5 (for customers moving to the rate). Since the customer counts in cells B5-B8 are already adjusted for rate switching, it is necessary to use the sum of cells

B5-B8 in cell F260, and remove the impact of rate switching to present the customers for the 13-month period unadjusted in cell C260.

b. See the response to part a. Cells F5 through F8 include the impact of rate switching, which is identified in cells X5 through Y8.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 24

Responding Witness: Robert M. Conroy

Q-24. Refer to the response to Item 88 of Staff's Second Request.

a. The response to Item 88.b. states that the "Annualized FAC roll-in to base rates" amount was allocated to each rate class based on the "calculated difference in FAC revenues on Conroy Exhibit P2, page 3 of 3." Explain why, for each rate class, it would not have been more appropriate to use the net difference between the "Total 12 Mos. Ended" column on Conroy Exhibit P2, page 3 of 3, and the "Increased Revenue" column on Conroy Exhibit P1, page 1 of 18, given that the total of the two columns net to the $2,885,839 amount being allocated.

b. The response to Item 88.c. states that the year-end customer adjustment was inadvertently not updated in the final version of the cost-of-service study. State how the results of the cost-of-service study would change if the adjustment had been updated.

A-24. a. KU believes that the method it used and the method suggested by Staff will both yield reasonable results. KU used the method that has consistently been used in previous cost of service studies.

b. KU recalculated the cost of service correcting the year end revenue adjustment. See the table below for the impact on Net Operating Income – Adjusted for this correction. The small changes to net operating income – adjusted do not impact the pro forma rate of return.

Kentucky Utilities	Net Operating Income -- As Filed	Net Operating Income -- As Revised, Year End Customer Adjustment	Change in Net Operating Income
Residential	$ 82,488,863	$ 82,488,781	$ (83)
General Service	$ 42,162,506	$ 42,162,511	$ 5
All Electric School	$ 2,214,365	$ 2,214,373	$ 9
Power Service	$ 48,810,805	$ 48,810,623	$ (182)
Power Service	$ 9,930,896	$ 9,930,946	$ 50
Time of Day Secondary	$ 5,117,967	$ 5,117,980	$ 14
Time of Day-Primary	$ 35,770,110	$ 35,769,899	$ (211)
Retail Transmission	$ 14,372,106	$ 14,372,125	$ 19
Fluctuating Load	$ 3,332,768	$ 3,332,768	$ -
Outdoor Lighting	$ 7,106,941	$ 7,107,321	$ 379
Lighting Energy	$ 237	$ 237	$ -
Traffic Energy	$ 25,956	$ 25,957	$ 1

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 25

Responding Witness: Robert M. Conroy

Q-25. Refer to the response to Item 92 of Staff's Second Request.

a. The response to Item 92.b.(1), at the bottom of page 2 of 3, shows late payment charges of $6,190,624 from Exhibit Conroy R4 and $6,910,624 from Exhibit Conroy C2. State which is the correct amount.

b. The response to Item 92.b.(2), page 3 of 3, refers to "rebilling." Explain the circumstances under which "rebilling" is necessary.

A-25. a. The correct amount is $6,910,624. See attached for a revised Conroy Exhibit R4.

b. A "rebilling" is necessary when an adjustment to a previous month's billing is needed. An adjustment may be necessary for a number of causes. Examples of when a "rebilling" may be performed include when actual meter data is obtained after a period of estimated meter data, when a defective meter is identified and the defect resulted in inaccurate billing, or when recent information obtained from a customer indicates that previous data used for billing was incorrect.

Kentucky Utilities Company
Summary of Proposed Increase
Based On Sales for the Twelve Months Ended March 31, 2012

	Revenue Adjusted to as Billed Basis	Adjustment to Remove Fuel Adjustment Clause Billings	Adjustment to Remove DSM Billings	Adjustment to Remove ECR Billings	Adjustment to Remove Merger Surcredit Billings	Adjustment to Remove HEA, Franchise Fees and Misc Revenue	Adjustment to Remove Interruptible Buy-thru Revenue	Test Year Base Revenues, As Billed	Adjustment to Reflect a Full Year of Base Rate Changes for FAC Rollin	Adjustment to Reflect a Full Year of Base Rate Changes for ECR Rollin	Test Year Base Revenues, At Current Rates
Residential Rate - RS	$ 481,362,814	$ 2,593,257	$ 11,425,450	$ 14,370,108	$ -	$ 8,476,853	$ -	$ 444,497,146	$ (1,105,429)	$ 14,613,748	$ 458,005,465
General Service Rate - GS	$ 184,154,601	$ 1,033,757	$ 3,105,553	$ 5,441,411	$ (4)	$ 3,169,217	$ -	$ 171,404,667	$ (393,289)	$ 11,147,080	$ 182,158,458
All Electric School Service Rate - AES	$ 11,258,851	$ 76,170	$ 38,693	$ 334,865	$ 22	$ 177,565	$ -	$ 10,631,536	$ (34,668)	$ 71,398	$ 10,668,266
Power Service Rate											
Power Service Rate PS - Secondary	$ 225,868,342	$ 1,728,895	$ 527,094	$ 6,481,232	$ (20)	$ 4,276,826	$ -	$ 212,854,315	$ (647,899)	$ 9,190,337	$ 221,396,753
Power Service Rate PS - Primary	$ 52,164,958	$ 438,178	$ 97,296	$ 1,489,519	$ -	$ 717,095	$ 2,843	$ 49,420,027	$ (192,686)	$ 1,997,208	$ 51,224,549
	$ 278,033,300	$ 2,167,073	$ 624,390	$ 7,970,751	$ (20)	$ 4,993,921	$ 2,843	$ 262,274,342	$ (840,585)	$ 11,187,545	$ 272,621,302
Time of Day Secondary Service TODS	$ 25,639,208	$ 221,536	$ 70,049	$ 739,189	$ -	$ 507,052	$ -	$ 24,101,382	$ (84,328)	$ (1,127,163)	$ 22,889,891
Time of Day Primary Service TODP	$ 204,406,942	$ 2,013,521	$ 137,309	$ 5,888,222	$ -	$ 2,191,634	$ 38,353	$ 194,137,903	$ (678,789)	$ (9,411,757)	$ 184,047,357
Retail Transmission Service -- RTS	$ 85,627,393	$ 847,670	$ -	$ 2,464,908	$ -	$ 136,830	$ -	$ 82,177,985	$ (341,016)	$ (1,950,925)	$ 79,886,044
Fluctuating Load Service FLS	$ 26,235,092	$ 296,727	$ -	$ 745,290	$ -	$ -	$ -	$ 25,193,075	$ (112,199)	$ (978,636)	$ 24,102,240
Curtailable Service Riders - CSR10	$ (12,053,715)	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,053,715)	$ -	$ -	$ (12,053,715)
Curtailable Service Riders - CSR30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Curtailable Service Riders	$ (12,053,715)	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,053,715)	$ -	$ -	$ (12,053,715)
Lighting Energy -- LE	$ 2,309	$ 17	$ -	$ 63	$ -	$ 64	$ -	$ 2,165	$ (8)	$ 98	$ 2,255
Traffice Lighting Energy -- TE	$ 109,808	$ 565	$ -	$ 3,101	$ -	$ 3,114	$ -	$ 103,028	$ (196)	$ 2,733	$ 105,565
Dark Sky Lighting - DSK	$ 87	$ -	$ -	$ 3	$ -	$ -	$ -	$ 84	$ -	$ 1	$ 85
Street Lighting - SL	$ 10,362,100	$ 18,993	$ -	$ 291,075	$ -	$ 241,976	$ -	$ 9,810,056	$ (9,485)	$ 305,950	$ 10,106,521
Private Outdoor Lighting - POL	$ 13,189,165	$ 31,413	$ -	$ 381,708	$ (1)	$ 194,349	$ -	$ 12,581,696	$ (16,233)	$ 415,264	$ 12,980,727
Outdoor and Street Lighting, LS and RLS	$ 23,551,352	$ 50,406	$ -	$ 672,786	$ (1)	$ 436,325	$ -	$ 22,391,836	$ (25,718)	$ 721,215	$ 23,087,333
TOTAL ULTIMATE CONSUMERS	$ 1,308,327,955	$ 9,300,699	$ 15,401,444	$ 38,630,694	$ (3)	$ 20,092,575	$ 41,196	$ 1,224,861,350	$ (3,616,225)	$ 24,275,336	$1,245,520,461
Late Payment Charges	6,910,624							$ 6,910,624			$ 6,910,624
Electric Service Revenues	2,206,637							$ 2,206,637			$ 2,206,637
Rent from Electric Property	2,153,990							$ 2,153,990			$ 2,153,990
Other Miscellaneous Electric Revenue	181,175							$ 181,175			$ 181,175
TOTAL JURISDICTIONAL	$ 1,319,780,381	$ 9,300,699	$ 15,401,444	$ 38,630,694	$ (3)	$ 20,092,575	$ 41,196	$ 1,236,313,776	$ (3,616,225)	$ 24,275,336	$1,256,972,887

Kentucky Utilities Company
Summary of Proposed Increase
Based On Sales for the Twelve Months Ended March 31, 2012

	Adjustment to Reflect FAC Billings for Full Year of the Rollin	Adjustment Reflecting Year-End Number of Customers	Adjustment to Reflect Customer Billing Move to Cycle 20	Adjustment to Reflect Removal of Base Rate ECR Revenues	Adjustment to Reflect Elimination of ECR Plans	Adjustment Reflecting Rate Switching	Adjusted Billings Net of ECR at Current Rates
Residential Rate - RS	$ 4,705,954	$ (710,225)	$ -	$ (56,592,842)	$ 54,809,454	$ (30,891)	$ 460,186,915
General Service Rate - GS	$ 1,757,425	$ 42,721	$ -	$ (27,494,815)	$ 26,620,421	$ (3,346,954)	$ 179,737,256
All Electric School Service Rate - AES	$ 129,005	$ 73,529	$ -	$ (1,328,040)	$ 1,285,505	$ (20,438)	$ 10,807,827
Power Service Rate							
Power Service Rate PS - Secondary	$ 2,893,212	$ (1,562,556)	$ -	$ (27,054,868)	$ 26,179,563	$ (1,353,663)	$ 220,498,441
Power Service Rate PS - Primary	$ 759,739	$ 171,787	$ -	$ (6,225,132)	$ 6,023,730	$ (5,386,209)	$ 46,568,464
	$ 3,652,951	$ (1,390,769)	$ -	$ (33,280,000)	$ 32,203,293	$ (6,739,872)	$ 267,066,905
Time of Day Secondary Service TODS	$ 3,264,159	$ 116,378	$ -	$ (2,577,384)	$ 2,503,037	$ 2,518,028	$ 28,714,109
Time of Day Primary Service TODP	$ 371,304	$ (1,816,142)	$ (1,640,196)	$ (19,026,087)	$ 18,303,577	$ 4,955,272	$ 185,195,086
Retail Transmission Service -- RTS	$ 1,400,173	$ 166,983	$ (2,832,550)	$ (7,866,500)	$ 7,644,909	$ (116,695)	$ 78,282,364
Fluctuating Load Service FLS	$ 475,259	$ -	$ (2,008,648)	$ (2,469,091)	$ 2,410,303	$ -	$ 22,510,063
Curtailable Service Riders - CSR10	$ -	$ -	$ 914,086	$ -	$ -	$ -	$ (11,139,629)
Curtailable Service Riders - CSR30	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Curtailable Service Riders	$ -	$ -	$ 914,086	$ -	$ -	$ -	$ (11,139,629)
Lighting Energy -- LE	$ 27	$ -	$ -	$ (381)	$ 262	$ -	$ 2,163
Traffice Lighting Energy -- TE	$ 938	$ 11,068	$ -	$ (10,650)	$ 7,316	$ 70	$ 114,307
Dark Sky Lighting - DSK	$ -	$ -	$ -	$ -	$ -	$ -	
Street Lighting - SL	$ 32,546	$ -	$ -	$ -	$ -	$ -	
Private Outdoor Lighting - POL	$ 55,314	$ -	$ -	$ -	$ -	$ -	$ -
Outdoor and Street Lighting, LS and RLS	$ 87,860	$ 98,915	$ -	$ (2,862,245)	$ 2,773,810	$ -	$ 23,185,673
TOTAL ULTIMATE CONSUMERS	$ 15,845,055	$ (3,407,542)	$ (5,567,308)	$ (153,508,035)	$ 148,561,887	$ (2,781,480)	$ 1,244,663,039
Late Payment Charges							6,910,624
Electric Service Revenues							2,206,637
Rent from Electric Property							2,153,990
Other Miscellaneous Electric Revenue							181,175
TOTAL JURISDICTIONAL	$ 15,845,055	$ (3,407,542)	$ (5,567,308)	$ (153,508,035)	$ 148,561,887	$ (2,781,480)	$ 1,256,115,465

Kentucky Utilities Company
Summary of Proposed Increase
Based On Sales for the Twelve Months Ended March 31, 2012

	Adjusted Billings Net of ECR at Current Rates	Add Base ECR Revenues	ECR Billing Factor Revenues Reflecting Rollin	Adjusted Billings Including All ECR Revenue at Current Rates	Increase		Percentage Increase
Residential Rate - RS	$ 460,186,915	$ 1,783,388	$ 3,624,607	$ 465,594,910	$ 37,381,886		8.03%
General Service Rate - GS	$ 179,737,256	$ 874,394	$ 1,686,683	$ 182,298,333	$ 9,061,201		4.97%
All Electric School Service Rate - AES	$ 10,807,827	$ 42,535	$ 80,784	$ 10,931,146	$ 635,467		5.81%
Power Service Rate							
Power Service Rate PS - Secondary	$ 220,498,441	$ 875,305	$ 1,791,384	$ 223,165,130	$ 4,381,192		1.96%
Power Service Rate PS - Primary	$ 46,568,464	$ 201,402	$ 445,709	$ 47,215,575	$ 2,504,301		5.30%
	$ 267,066,905	$ 1,076,707	$ 2,237,093	$ 270,380,705	6,885,493		2.55%
Time of Day Secondary Service TODS	$ 28,714,109	$ 74,347	$ 142,467	$ 28,930,923	1,907,198		6.59%
Time of Day Primary Service TODP	$ 185,195,086	$ 722,510	$ 1,064,717	$ 186,982,312	$ 12,380,611		6.62%
Retail Transmission Service -- RTS	$ 78,282,364	$ 221,591	$ 448,130	$ 78,952,085	$ 5,128,398		6.50%
Fluctuating Load Service FLS	$ 22,510,063	$ 58,788	$ 110,713	$ 22,679,564	$ 1,417,956		6.25%
Curtailable Service Riders - CSR10	$ (11,139,629)	$ -	$ -	$ (11,139,629)	$ 5,466,756		
Curtailable Service Riders - CSR30	$ -	$ -	$ -	$ -	$ -		
Total Curtailable Service Riders	$ (11,139,629)	$ -	$ -	$ (11,139,629)	5,466,756		
Lighting Energy -- LE	$ 2,163	$ 119	$ 7	$ 2,289	$ 124		5.42%
Traffice Lighting Energy -- TE	$ 114,307	$ 3,334	$ 682	$ 118,323	$ 6,388		5.40%
	-						
Dark Sky Lighting - DSK	$ -						
Street Lighting - SL	$ -						
Private Outdoor Lighting - POL	$ -						
Outdoor and Street Lighting, LS and RLS	$ 23,185,673	$ 88,435	$ 168,549	$ 23,442,657	$ 1,267,776		5.41%
TOTAL ULTIMATE CONSUMERS	$ 1,244,663,039	$ 4,946,148	$ 9,564,432	$ 1,259,173,618	$ 81,539,255		6.48%
Late Payment Charges	6,910,624			$ 6,910,624			
Electric Service Revenues	2,206,637			$ 2,206,637			
Rent from Electric Property	2,153,990			$ 2,153,990	$ 681,722	(1)	
Other Miscellaneous Electric Revenue	181,175			$ 181,175	$ 247,419	(2)	
TOTAL JURISDICTIONAL	$ 1,256,115,465			$ 1,270,626,044	$ 82,468,396		6.49%

(1) Increase in the CATV Pole Attachment charge.
(2) Increase in the Meter Pulse Relay, Disconnect/Reconnect, and Meter Test Charges

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 26

Responding Witness: Robert M. Conroy

Q-26. Refer to the response to Item 93 of Staff's Second Request.

a. For each of the three lights discussed in the response to Item 93.c., provide the number of customers that would be affected by the proposed increase. For each light, provide the largest number of lights billed to a single customer.

b. The response to Item 93.d.(1) did not explain how an increase of 55 percent satisfies the principle of gradualism. Provide the requested explanation.

c. Refer to the response to Item 93.d.(2). Identify the customer referred to in the response.

A-26. a. Item 93(c) of Staff's Second Request states in part "Refer to page 13 of 16. KU is proposing an increase of 14.73 percent for the "9,500L Contemp Décor UG RC-484" light, a 20 percent increase for the "22,000L Contemp Décor UG RC-485" light, and a 15.6 percent increase for the "50,000L Contemp Décor UG RC-486" light." KU's response identified lights with codes 484, 485, and 486 as being proposed to receive the increases calculated by Staff. However, on further examination of Conroy Exhibit R5, KU realized that the lighting descriptions presented on Conroy Exhibit R5, page 2 Contemporary Fixture and Pole 9,500L RC-484, 22,000L Contemp Décor RC 485, and 50,000 Contemp Décor RC-486 were on the incorrect rows. The lighting types that are proposed to receive the percentage increases referenced in PSC 2-93c are Contemporary RC-477, RC-478, and RC-479. A revised Conroy Exhibit R5, page 13 of 16 is attached. The information requested is being provided for lights 477, 478, and 479:

Light Type	Number of Accounts	Maximum Lights Billed on One Account
9,500L Contemporary HPS UG RC-477	9	454
22,000L Contemporary HPS UG RC-478	11	501
50,000L Contemporary HPS UG RC-479	3	78

b. KU applies the cost of service principle of gradualism when determining the appropriate increase to request for specific customer classes and when designing rates for its rate classes as a whole. It is not feasible to employ this principle on an individual customer basis. Specifically in regards to its lighting rates, KU is seeking in this proceeding to simplify its lighting options, clarify the circumstances under which lights may be installed, and specify which lights that are currently in service may not be installed in new locations. This process resulted in combining similar lights under one rate; and of necessity, some lighting types are proposed to receive larger increases than proposed for the lighting group as a whole. KU does not believe this outcome is contrary to the principle of gradualism as it is applied to the entire rate class. KU believes the simplified tariff schedules and increased clarity resulting from its proposals are of general benefit to its customers. Furthermore, for consistency the Company is attempting to adjust its rates in order to charge equivalent charges for equivalent services and similar charges for similar services.

c. See attached. The requested information is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2) Existing Tariff Sheet	(3) Existing Bill Code	(4) Total Lights	(5) Present Rates	(6) Calculated Revenue at Present Rates	(7) Proposed Bill Code	(8) Total Lights	(9) Proposed Rates	(10) Calculated Revenue at Proposed Rates
LIGHTING SERVICE, CONTINUED									
Underground									
High Pressure Sodium									
Colonial, 5800 Lumen, Decorative						467	**15,454**	**$ 10.47**	**$ 161,803**
5,800L Colonial HPS UG RC-467	St.Lt. 35.1	467	13,508	$ 9.93	$ 134,134				
5,800L Colonial Decor UG RC-481	P.O.L. 36.1	481	1,946	$ 9.93	$ 19,324				
Colonial, 9500 Lumen, Decorative						468	**44,225**	**$ 10.92**	**$ 482,937**
9,500L Colonial HPS UG RC-468	St.Lt. 35.1	468	23,395	$ 10.35	$ 242,138				
9,500L Colonial Decor UG RC-482	P.O.L. 36.1	482	20,830	$ 10.35	$ 215,591				
Acorn, 5800 Lumen, Smooth Pole						401	**624**	**$ 14.62**	**$ 9,123**
5,800L Acorn (D Pole) HPS UG	St.Lt. 35.1	401	420	$ 13.86	$ 5,821				
5,800L Acorn (Decorative Pole) UG RC-441	P.O.L. 36.1	441	204	$ 13.86	$ 2,827				
Acorn, 5800 Lumen, Fluted Pole						411	**1,752**	**$ 21.24**	**$ 37,212**
5,800L Acorn (Hist Pole) HPS UG	St.Lt. 35.1	411	864	$ 20.14	$ 17,401				
5,800L Acorn (Historic Pole) UG RC-445	P.O.L. 36.1	445	888	$ 20.14	$ 17,884				
Acorn, 9500 Lumen, Smooth Pole						420	**4,993**	**$ 15.18**	**$ 75,794**
9,500L Acorn (D Pole) HPS UG RC-420	St.Lt. 35.1	420	2,275	$ 14.39	$ 32,737				
9,500L Acorn (Decorative Pole) UG RC-442	P.O.L. 36.1	442	2,718	$ 14.39	$ 39,112				
Acorn, 9500 Lumen, Fluted Pole						430	**12,932**	**$ 21.92**	**$ 283,469**
9,500L Acorn (Hist Pole) HPS UG	St.Lt. 35.1	430	5,292	$ 20.78	$ 109,968				
9,500L Acorn (Historic Pole) UG RC-449	P.O.L. 36.1	449	7,640	$ 20.78	$ 158,759				
Victorian, 5800 Lumen, Fluted Pole						414	**252**	**$ 30.84**	**$ 7,772**
5,800L Coach HPS UG	P.O.L. 36.1	414	252	$ 29.24	$ 7,368				
Victorian, 9500 Lumen, Fluted Pole						415	**120**	**$ 31.27**	**$ 3,752**
9,500L Coach HPS UG RC-415	P.O.L. 36.1	415	120	$ 29.65	$ 3,558				
Contemporary Fixture and Pole, 5800 Lumen, Second Fixture						492	**6**	**$ 15.13**	**$ 91**
5,800L UG HPS Contemporary Fixture Only	P.O.L. 36.1	492	6	$ 14.35	$ 86				
Contemporary Fixture and Pole, 5800 Lumen						476	**54,631**	**$ 16.58**	**$ 905,782**
5,800L Contemporary HPS UG RC-476	St.Lt. 35.1	476	54,099	$ 15.66	$ 847,190				
5,800L UG HPS Contemporary	P.O.L. 36.1	483	532	$ 21.81	$ 11,603				
Contemporary Fixture and Pole, 9500 Lumen, Second Fixture						497	**-**	**$ 15.17**	**$ -**
9,500L Contemp Decor UG Fixture Only	P.O.L. 36.1	497	-	$ 14.38	$ -				
Contemporary Fixture and Pole, 9500 Lumen						477	**11,878**	**$ 20.87**	**$ 247,894**
9,500L Contemporary HPS UG RC-477	St.Lt. 35.1	477	6,688	$ 18.19	$ 121,655				
9,500L Contemp Decor UG RC-484	P.O.L. 36.1	484	5,190	$ 21.85	$ 113,402				
Contemporary Fixture and Pole, 22000 Lumen, Second Fixture						498	**78**	**$ 17.27**	**$ 1,347**
22,000L UG HPS Contemporary (Add Fixture	P.O.L. 36.1	498	78	$ 16.37	$ 1,277				
Contemporary Fixture and Pole, 22000 Lumen						478	**16,443**	**$ 26.55**	**$ 436,562**
22,000L Contemporary HPS UG RC-478	St.Lt. 35.1	478	7,666	$ 22.11	$ 169,495				
22,000L Contemp Decor UG RC-485	P.O.L. 36.1	485	8,777	$ 27.84	$ 244,352				
Contemporary Fixture and Pole, 50000 Lumen, Second Fixture						499	**21**	**$ 20.72**	**$ 435**
50,000L Contemp Decor UG Fixture Only	P.O.L. 36.1	499	21	$ 19.65	$ 413				
Contemporary Fixture and Pole, 50000 Lumen						479	**11,124**	**$ 32.54**	**$ 361,975**
50,000L Contemporary HPS UG RC-479	St.Lt. 35.1	479	1,012	$ 28.13	$ 28,468				
50,000L Contemp Decor UG RC-486	P.O.L. 36.1	486	10,112	$ 31.12	$ 314,685				

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 27

Responding Witness: Robert M. Conroy

Q-27. Refer to the response to Item 94 of Staff's Second Request.

a. Provide a definition of "levelized carrying charge" and "non-levelized carrying charge".

b. Explain whether KU is familiar with the clarification of Administrative Case 251[5] in Case No. 2000-00359[6] in which the Commission found that calculation of CATV charges should use either net pole costs or a rate of return adjusted for the ratio of net plant to gross plant applied to the gross average pole costs. If yes, explain how KU's calculation complies with the methodology set out in Case No. 2000-00359.

A-27. a. A *levelized carrying charge* is a uniform series of payments calculated by applying a uniform series capital recovery factor to the gross original cost investment. A capital recovery factor is equal to the rate of return plus sinking fund depreciation. The calculation of a levelized carrying charge is identical to the calculation of a conventional mortgage payment on a home. In calculating a levelized carrying charge (or a mortgage payment), a capital recovery factor is applied to the original, un-depreciated investment ("gross investment"). Without considering income taxes, a levelized carrying charge (LCC) is therefore calculated by applying the return on investment (ROR) plus the sinking fund depreciation to the gross investment as follows:

$$LCC = Gross\ Investment\ x\ [ROR + Sinking\ Fund\ Depreciation\ Rate]$$

Mathematically, it is not appropriate to apply a capital recovery factor (which

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[5] Administrative Case 251, The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments (Ky. PSC Sept. 17, 1982).

[6] Case No. 2000-00359, Application of Cumberland Valley Electric, Inc. to Adjust Its Rates (Ky. PSC Feb. 26, 2001).

is equal to the rate of return plus sinking fund depreciation) to the depreciated investment ("net investment"). In the context of the proposed CATV attachment charge, applying a capital recovery factor – which reflects *sinking fund depreciation* as opposed to *straight line depreciation* – to net investment would result in a significant under-recovery of costs and would thus inappropriately shift these costs onto other customers.

A *non-levelized carrying charge* (NLCC) is a non-uniform series of payments calculated by applying the rate of return to net investment and then adding straight-line depreciation, as follows:

$$NLCC = Net\ Investment\ x\ ROR + Straight\ Line\ Depreciation$$

A non-levelized carrying charge calculation corresponds to the methodology used to determine revenue requirements in a rate case. Importantly, in a rate case *straight line depreciation* rather than *sinking fund depreciation* is used to calculate revenue requirements.

On a present value basis, levelized carrying charges are equivalent to non-levelized carrying charges over the life of the investment. This can be seen in the following attachment (Table I) which compares the present-value non-levelized carrying charges on a $1,000 investment to the present-value levelized carrying charges on the same $1,000 investment. Please note that for both calculations, the sum of the present value revenue carrying charges is equal to the original $1,000 investment.

But if sinking fund depreciation rather than straight-line depreciation is applied to the net investment then an incorrect result is obtained. As seen in Table II, calculating carrying charges by applying a *sinking fund depreciation* rate to the *net investment* results in significant under-recovery of carrying costs. When the levelized and non-levelized carrying charges are properly calculated, the sum of the present-value carrying charges for each series is equal to $1,000. But when sinking fund depreciation is applied to net investment, the sum of the present value carrying charges is only equal to $707.90. What this means is that if carrying charges are miscalculated in this manner, only 70.79% of cost will be recovered over the life of the investment.

The conclusion reached is that either methodology – either a levelized fixed charge calculation or non-levelized fixed charge calculation – is reasonable assuming that the methodologies are properly applied *and* assuming that the same methodology is consistently applied over time. While on a present value basis both methodologies will yield the same result over the life of the investment, during any particular year the carrying charges will likely be different. For this reason, generally it is not appropriate to switch back and forth between the two methodologies. While KU does not have a fundamental objection with using a non-levelized carrying charge calculation to determine CATV attachment charges *as long as straight-line depreciation is used in the calculation*, the Company does not believe that it is appropriate to switch back and forth between the two methodologies.

The use of levelized versus non-levelized carrying charge rates has been considered extensively by the Federal Energy Regulatory Commission ("FERC"). The FERC will allow the application of the levelized carrying charge rate (with sinking fund depreciation) to gross plant – which it calls the "levelized gross plant method" – or the application of a non-levelized carrying charge rate (with straight-line depreciation) to net plant – which it calls "nonlevelized net plant method". The FERC however, is reluctant to allow a utility to switch back and forth between the two methodologies. In a series of cases involving levelized carrying charges, the FERC rejected attempts to switch from a "net plant" approach to a "levelized" approach in midstream, finding that "allowing Consumers to switch pricing methodologies from the nonlevelized approach … to the levelized approach … is inappropriate." *Consumers Energy Co., Opinion No. 429*, 85 FERC ¶ 61,100 at 61,366 (1998), *reh'g granted, Opinion No. 429-A,* 89 FERC ¶ 61,138 (1999), *reh'g denied, Opinion No. 429-B*, 95 FERC ¶ 61,084 (2001); *accord Ky. Utils. Co., Opinion No. 432*, 85 FERC ¶ 61,274 at 62,105 (1998). In its *Opinion 432*, the FERC did not allow KU to change methodologies, stating as follows:

> In conclusion, we believe that either a levelized gross plant or a non-levelized rate design can produce comparable, reasonable results if they are used consistently. Here, however, KU proposes to switch methods. In supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method. Here, KU has not persuaded us that the switch is appropriate in the circumstances of this case.

Regarding CATV attachment charges, considering the historical practice of calculating the charges using the levelized gross plant methodology, the Company maintains that the historical practice should be continued in this current proceeding.

b. The Company is familiar with the clarification of Case No. 2000-00359. The Company does not have information concerning the net plant costs related to the types of poles (35 foot, 40 foot, and 45 foot poles) used to calculate the proposed CATV attachment charge. A rough estimate can be developed by applying the ratio of net plant to gross plant for Account 364 - Poles, Towers, and Fixtures to the applicable gross plant unit costs for 35, 40, and 45 foot poles. As explained above, using net plant necessitates the application of straight line depreciation rather than sinking fund depreciation. Since it has been a historical practice for The Company to use sinking fund depreciation when developing rates, the same method has been used in calculating the proposed rate for CATV attachments.

Table I

(a)	Book Life	35	Years
(b)	Straight Line Depreciation (1/(a))	2.86%	
(c)	Sinking-Fund Depreciation (see formula)	0.54%	
(d)	Rate of Return	8.32%	
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%	

	Non-Levelized Carrying Charges					Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Gross Investment (7)	Non-Levelized Carrying Charges (8)	Present Value at 8.32% ROR (6)
							[(e) x (7)]	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	1,000.00	88.60	75.51
3	942.86	78.45	28.57	107.02	84.20	1,000.00	88.60	69.71
4	914.29	76.07	28.57	104.64	76.01	1,000.00	88.60	64.36
5	885.71	73.69	28.57	102.26	68.58	1,000.00	88.60	59.42
6	857.14	71.31	28.57	99.89	61.84	1,000.00	88.60	54.85
7	828.57	68.94	28.57	97.51	55.73	1,000.00	88.60	50.64
8	800.00	66.56	28.57	95.13	50.19	1,000.00	88.60	46.75
9	771.43	64.18	28.57	92.75	45.18	1,000.00	88.60	43.16
10	742.86	61.81	28.57	90.38	40.64	1,000.00	88.60	39.84
11	714.29	59.43	28.57	88.00	36.53	1,000.00	88.60	36.78
12	685.71	57.05	28.57	85.62	32.82	1,000.00	88.60	33.96
13	657.14	54.67	28.57	83.25	29.45	1,000.00	88.60	31.35
14	628.57	52.30	28.57	80.87	26.42	1,000.00	88.60	28.94
15	600.00	49.92	28.57	78.49	23.67	1,000.00	88.60	26.72
16	571.43	47.54	28.57	76.11	21.19	1,000.00	88.60	24.67
17	542.86	45.17	28.57	73.74	18.95	1,000.00	88.60	22.77
18	514.29	42.79	28.57	71.36	16.93	1,000.00	88.60	21.02
19	485.71	40.41	28.57	68.98	15.11	1,000.00	88.60	19.41
20	457.14	38.03	28.57	66.61	13.47	1,000.00	88.60	17.92
21	428.57	35.66	28.57	64.23	11.99	1,000.00	88.60	16.54
22	400.00	33.28	28.57	61.85	10.66	1,000.00	88.60	15.27
23	371.43	30.90	28.57	59.47	9.46	1,000.00	88.60	14.10
24	342.86	28.53	28.57	57.10	8.39	1,000.00	88.60	13.01
25	314.29	26.15	28.57	54.72	7.42	1,000.00	88.60	12.02
26	285.71	23.77	28.57	52.34	6.55	1,000.00	88.60	11.09
27	257.14	21.39	28.57	49.97	5.77	1,000.00	88.60	10.24
28	228.57	19.02	28.57	47.59	5.08	1,000.00	88.60	9.45
29	200.00	16.64	28.57	45.21	4.45	1,000.00	88.60	8.73
30	171.43	14.26	28.57	42.83	3.90	1,000.00	88.60	8.06
31	142.86	11.89	28.57	40.46	3.40	1,000.00	88.60	7.44
32	114.29	9.51	28.57	38.08	2.95	1,000.00	88.60	6.87
33	85.71	7.13	28.57	35.70	2.55	1,000.00	88.60	6.34
34	57.14	4.75	28.57	33.33	2.20	1,000.00	88.60	5.85
35	28.57	2.38	28.57	30.95	1.89	1,000.00	88.60	5.40
Sum of Present Value Carrying Charges					$1,000.00			$1,000.00

Table II

(a)	Book Life	35	Years
(b)	Straight Line Depreciation (1/(a))	2.86%	
(c)	Sinking-Fund Depreciation (see formula)	0.54%	
(d)	Rate of Return	8.32%	
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%	

	Non-Levelized Carrying Charges					*Misapplied* Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Net Investment (7)	Non-Levelized Carrying Charges (8)	Present Value at 8.32% ROR (6)
							[(e) x (7)]	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	971.43	86.07	73.36
3	942.86	78.45	28.57	107.02	84.20	942.86	83.54	65.73
4	914.29	76.07	28.57	104.64	76.01	914.29	81.01	58.84
5	885.71	73.69	28.57	102.26	68.58	885.71	78.48	52.63
6	857.14	71.31	28.57	99.89	61.84	857.14	75.95	47.02
7	828.57	68.94	28.57	97.51	55.73	828.57	73.41	41.96
8	800.00	66.56	28.57	95.13	50.19	800.00	70.88	37.40
9	771.43	64.18	28.57	92.75	45.18	771.43	68.35	33.29
10	742.86	61.81	28.57	90.38	40.64	742.86	65.82	29.60
11	714.29	59.43	28.57	88.00	36.53	714.29	63.29	26.27
12	685.71	57.05	28.57	85.62	32.82	685.71	60.76	23.29
13	657.14	54.67	28.57	83.25	29.45	657.14	58.22	20.60
14	628.57	52.30	28.57	80.87	26.42	628.57	55.69	18.19
15	600.00	49.92	28.57	78.49	23.67	600.00	53.16	16.03
16	571.43	47.54	28.57	76.11	21.19	571.43	50.63	14.10
17	542.86	45.17	28.57	73.74	18.95	542.86	48.10	12.36
18	514.29	42.79	28.57	71.36	16.93	514.29	45.57	10.81
19	485.71	40.41	28.57	68.98	15.11	485.71	43.04	9.43
20	457.14	38.03	28.57	66.61	13.47	457.14	40.50	8.19
21	428.57	35.66	28.57	64.23	11.99	428.57	37.97	7.09
22	400.00	33.28	28.57	61.85	10.66	400.00	35.44	6.11
23	371.43	30.90	28.57	59.47	9.46	371.43	32.91	5.24
24	342.86	28.53	28.57	57.10	8.39	342.86	30.38	4.46
25	314.29	26.15	28.57	54.72	7.42	314.29	27.85	3.78
26	285.71	23.77	28.57	52.34	6.55	285.71	25.32	3.17
27	257.14	21.39	28.57	49.97	5.77	257.14	22.78	2.63
28	228.57	19.02	28.57	47.59	5.08	228.57	20.25	2.16
29	200.00	16.64	28.57	45.21	4.45	200.00	17.72	1.75
30	171.43	14.26	28.57	42.83	3.90	171.43	15.19	1.38
31	142.86	11.89	28.57	40.46	3.40	142.86	12.66	1.06
32	114.29	9.51	28.57	38.08	2.95	114.29	10.13	0.78
33	85.71	7.13	28.57	35.70	2.55	85.71	7.59	0.54
34	57.14	4.75	28.57	33.33	2.20	57.14	5.06	0.33
35	28.57	2.38	28.57	30.95	1.89	28.57	2.53	0.15
Sum of Present Value Carrying Charges					$1,000.00			$721.54

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information Dated August 28, 2012

Question No. 28

Responding Witness: Robert M. Conroy

Q-28. Refer to LG&E's response to Item 96.d. of Staff's Second Request for Information in Case No. 2012-00222.[7] Compare KU's current practice to LG&E's with regard to the inclusion of Interchange In and Interchange Out energy in the fuel adjustment clause filing. Explain whether KU would need to propose a change to its current practice to match that proposed by LG&E in Case No. 2012-00222, including whether a change would be needed to page 3 of Form A.

A-28. KU currently includes net interchange energy in its fuel adjustment clause filings. LG&E's proposal is to make LG&E's FAC consistent with KU's FAC. No changes are needed to KU's current practice. The titles on page 3 of Form A refer to "Interchange In" and "Interchange Out," which include purchases and inter-system sales. KU does not believe a change to the titles is necessary if LG&E's proposed change to the FAC is approved.

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[7] Case No. 2012-00222, Application of Louisville Gas and Electric Company for an Adjustment of Its Electric Rates, filed July 10, 2012.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 29

Responding Witness: Sidney L. "Butch" Cockerill

Q-29. Refer to KU's response to Item 11 of the Attorney General's Initial Data Request ("AG's First Request"). The response states that bills are due on working days and not weekends and holidays. In instances when the due date falls on a weekend or holiday, explain whether the due date is moved to the following working day.

A-29. In instances when the bill due date would fall on a weekend or holiday, the due date is moved to the following working day.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 30

Responding Witness: Robert M. Conroy

Q-30. Refer to KU's response to Item 261 of the AG's First Request which states that "the customers' CP demands were adjusted to reflect levels that would have occurred had the customers not been curtailed." Explain why CP demands should not reflect the curtailed levels.

A-30. Customers receive a credit through the imputation of avoided cost in the cost of service study. If a customer is curtailed at the time of the summer system peak and if the customer's actual unadjusted curtailed load were used in the allocator, then the customer would not be allocated *any* summer production cost *and* would receive the benefit of the curtailable credit in the cost of service study which is based on imputed avoided costs. Therefore the customer would then effectively receive two credits – one for the avoided cost that is assigned to the customer in the study (based on the value of the credit) and the other for the reduction in load at the time of the peak. In that case, the curtailable customer would not pay Summer Peak Period Costs but would also receive an additional credit through the assignment of the avoided cost credit, which would not be a reasonable approach.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 31

Responding Witness: Robert M. Conroy

Q-31. Refer to KU's response to Item 5 of the Kentucky School Boards Association's Initial Request for Information. Provide the additional cost of time-based metering to which this response refers.

A-31. The difference in pricing for time-based metering is $19.40 plus labor.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 32

Responding Witness: Sidney L. "Butch" Cockerill

Q-32. Refer to KU's response to Item 24 of the Lexington-Fayette Urban County Government's ("LFUCG") Initial Request for Information, page 1 of 3. The response shows that LFUCG has 38 "Residential Service" accounts, seven "Residential Service-All Electric" accounts, and one "Residential Service-Three Phase" accounts.

a. Explain the circumstances under which LFUCG has "Residential" accounts.

b. Explain the differences in these "Residential" accounts and whether each is charged at the standard Residential Service rate.

A-32. a. Of the 46 accounts listed as Residential Service in response LFUCG 1-24 Initial Request for Information, page 1 of 3, only 4 are actually LFUCG accounts. The other 42 accounts belong to the Lexington Housing Authority and were inadvertently including in the response. Of the four LFUCG accounts, three were incorrectly coded as residential and are being corrected. The one LFUCG account correctly coded as residential provides service to the Glen Rose residence located next to the fire training on Old Frankfort Pike.

b. There is no difference in the "Residential Service," "Residential Service-All Electric," and "Residential Service-Three Phase" accounts. The description difference serves as an internal descriptor. Each of these Residential accounts is charged the same Basic Service Charge and Energy Charge.

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 33

Responding Witness: Robert M. Conroy

Q-33. Refer to KU's response to Item 6 of the Kentucky Industrial Utility Customers, Inc.'s First Set of Data Requests, which refers to an attached analysis; however, no analysis was attached to the response. Provide the referenced analysis.

A-33. The analysis referenced at the end of the response to KIUC 1-6 was referring to the information provided in response to PSC 2-75. The response should have stated "Those ratios and the development of the rate switching adjustments used in the cost of service study *are included in the supporting workpapers provided in response to PSC 2-75*." The referenced analysis is contained in "Att-PSC2-75-File 24" ('Support for C-4 - Rate Switching Analysis Final.xlsx').