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PUBLIC SERVICE COMMISSION

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Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
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Louisville, Kentucky 40232
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Lonnie E. Bellar
Vice President
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Ms. Stephanie L. Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

October 7, 2008

RE: ***Application of Kentucky Utilities Company for an Adjustment of Base Rates* – Case No. 2008-00251**

***Application of Kentucky Utilities Company to File Depreciation Study* – Case No. 2007-00565**

Dear Ms. Stumbo:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Kentucky Utilities Company to the Commission Staff's Third Data Request dated September 24, 2008, in the above-referenced matters.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Lonnie E. Bellar

Lonnie E. Bellar

cc: Parties of Record

Counsel of Record

Allyson K. Sturgeon, Senior Corporate Attorney – E.ON U.S. LLC
Robert M. Watt – Stoll Keenon Ogden PLLC (Kentucky Utilities)
Kendrick R. Riggs – Stoll Keenon Ogden PLLC (Kentucky Utilities)
W. Duncan Crosby – Stoll Keenon Ogden PLLC (Kentucky Utilities)
Dennis Howard II – Office of the Attorney General (AG)
Lawerence W. Cook – Office of the Attorney General (AG)
Paul D. Adams – Office of the Attorney General (AG)
Michael L. Kurtz – Boehm, Kurtz & Lowry (KIUC)
David C. Brown – Stites and Harbison (Kroger)
Willis L. Wilson – LFUCG Department of Law (LFUCG)
Joe F. Childers (CAK and CAC)

Consultants to the Parties

Steve Seelye – The Prime Group (E.ON U.S. LLC)
William A. Avera – FINCAP, Inc (E.ON U.S. LLC)
John Spanos – Gannett Fleming, Inc. (E.ON U.S. LLC)
Robert Henkes (AG)
Michael Majoros – Snavely King Majoros O'Connor & Lee (AG)
Glenn Watkins – Technical Associates (AG)
Dr. J. Randall Woolridge – Smeal College of Business (AG)
Lane Kollen – Kennedy and Associates (KIUC)
Kevin C. Higgins – Energy Strategies, LLC (Kroger)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2008-00251**
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00565**

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO THE
THIRD DATA REQUEST OF COMMISSION STAFF
DATED SEPTEMBER 24, 2008

FILED: OCTOBER 7, 2008

VERIFICATION

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

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

SBRives
S. BRADFORD RIVES

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

VERIFICATION

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

The undersigned, **Chris Hermann**, being duly sworn, deposes and says he is Senior Vice President – Energy Delivery for Kentucky Utilities Company, that he has personal knowledge of the matters set forth in the foregoing testimony, 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 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paula H. Pottinger, Ph.D.**, being duly sworn, deposes and says that she is the Senior Vice President, Human Resources for Kentucky Utilities Company, 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.

Paula H. Pottinger

PAULA H. POTTINGER, Ph.D.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is the Senior Vice President, Energy services for Kentucky Utilities Company, 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

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is the Vice President, State Regulation and Rates for Kentucky Utilities Company, 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 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

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

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

Valerie L. Scott
VALERIE L. SCOTT

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is the Director, Rates for Kentucky Utilities Company, 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

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of October, 2008.

(SEAL)
Notary Public

My Commission Expires:
November 9, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Butch Cockerill**, being duly sworn, deposes and says that he is Director, Revenue Collection for Kentucky Utilities Company, 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.

Butch Cockerill
BUTCH COCKERILL

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

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

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is the Director, Utility Accounting for Kentucky Utilities Company, 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 3rd day of October, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and says that he is the Senior Consultant and Principal, for The Prime Group, LLC, 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.

WILLIAM STEVEN SEELYE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of October, 2008.

Tammy J. Ely (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is the 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 State, this 30th day of September, 2008.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2011

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb 20, 2011
Member, Pennsylvania Association of Notaries

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF ____________)

The undersigned, **William E. Avera**, being duly sworn, deposes and says that he is President of FINCAP, 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.

WILLIAM E. AVERA

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of October, 2008.

_____________________(SEAL)
Notary Public

My Commission Expires:

1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan 10, 2011

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 1

Responding Witness: William Steven Seelye

Q-1. Refer to KU's response to Item 1, page 6, of the Commission Staff's Second Data Request dated August 27, 2008 ("Staff's Second Request"). In paragraph e(2), KU states that "[n]o customers currently receiving service under this rate would be affected by this change." Paragraph e(3) states that KU does not propose to continue to serve customers currently receiving the primary discount on rate GS and that "they will be migrated to the proposed rate PS." Provide the cost impact for those customers who will be migrated to the proposed rate PS.

A-1. In stating that "[n]o customers currently receiving service under this rate would be affected by this change," the Company was referring to changes applicable to secondary service under Rate GS.

The cost impact for the primary voltage Rate GS customers who will be migrated to the proposed Rate PS is shown on page 4 of Exhibit 5 to Mr. Seelye's testimony. As can be seen in that analysis, which is attached hereto, migrating the primary voltage Rate GS customers to a standard *demand-metered* rate schedule will result in an increase of $446,784, which is equivalent to a 15.27 percent increase. However, serving these customers under a three-part rate consisting of a customer charge, demand charge, and energy charge would encourage them to improve the efficiency of their power consumption, thus reducing the impact on their bills.

Over the years, both KU and LG&E have been making tariff modifications to *reduce* the number of commercial and industrial (C&I) customers served on two-part rate schedules consisting of only a customer charge and energy charge and thereby *increasing* the number of C&I customers served under three-part rate schedules consisting of a customer charge, energy charge and demand charge. A three-part rate structure that includes a demand charge will more accurately reflect the cost of providing service and encourages customers to improve the efficiency of their power consumption by improving load factor. Requiring primary voltage Rate GS customers to take service under a *standard* demand-metered schedule is simply a continuation of the Companies' efforts to serve customers under rate schedules that more accurately recover the actual cost of providing service. Historically, many primary voltage customers served under Rate GS have had extremely low load factors and have thus placed a high kW demand on the system but are billed a relatively low energy charge because of their low kWh usage. Serving low load factor customers under a two-part rate schedule consisting of only a customer charge and energy charge does not encourage customers to improve the efficiency of their power consumption through improvements in load factor and also has the effect of increasing the overall cost to customers in the rate that have higher load factors.

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
GSP - Rate Codes 111, 151 (Customers to be Served Under Rate PS)						
Customer Charges	872		$ 10.00	$ 8,720	$ 75.00	65,400
All KWH		43,720,684	$ 0.06745	2,948,960	$ 0.03282	1,434,913
Minimum Energy				81,888		90,045
Demand (KW)	241,323				7.26	1,752,004
Demand Discount				(150,182)		-
Total Calculated at Base Rates				$ 2,889,386		$ 3,342,361
Correction Factor				0.999780		0.999780
Total After Application of Correction Factor				$ 2,890,020		$ 3,343,095
Fuel Clause Billings - proforma for rollin				76,202		76,202
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(40,127)		(46,418)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 2,926,095		3,372,879
Proposed Increase						446,784
	Percentage Increase					15.27%

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 2

Responding Witness: Butch Cockerill

Q-2. Refer to KU's response to Item 1, page 7, of Staffs Second Request. In paragraph m, KU states that special equipment is installed to provide the customer with real time data which allows the customer to control its electric power demand. Explain in detail how this special equipment allows the customer to control its electric power demand.

A-2. A pulse initiator is installed in the electric meter that provides the customer a pulse the instant the meter registers a predetermined kilowatt hour. By tracking the total pulses, the customer knows their approximate energy use and can control their load.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 3

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-3. Refer to KU's responses to Items 4 and 58 of Staff's Second Request. In the first response, KU states that accrued expenses were not removed because there were no accrued expenses associated with the accrued revenues listed. In the second response, KU states that it did not accrue any "unbilled expenses" concurrently with the recording of unbilled revenue.

a. Explain how accrued fuel adjustment clause ("FAC") and environmental cost recovery revenues can have no associated accrued expenses.

b. Explain how recording unbilled revenue without associated expenses satisfies the "matching principle" as dictated by generally accepted accounting principles.

c. KU is proposing an adjustment for accrued revenues (Rives Testimony at Schedule 1.09) and unbilled revenues (Rives Testimony at Schedule 1.00). Explain the distinction between accrued revenues and unbilled revenues and state whether accrued revenues are also unbilled.

A-3. a. The Company is not claiming that accrued fuel adjustment clause ("FAC") and environmental cost recovery revenues have no associated accrued expenses. The Company follows accrual-basis accounting and accordingly records liabilities for all goods and services received in each accounting period. Using this accrual-basis method, each 12-month period contains 12 months worth of expenses. All ECR and FAC expenses are removed through the *pro forma* adjustments shown at Rives Exhibit 1 Reference Schedules 1.03 and 1.05.

b. The Company follows the matching principle for accounting purposes, as dictated by GAAP, by recording unbilled revenues and accrued expenses to match revenues earned in the month with actual expenses incurred in the same month.

For ratemaking purposes, the Company develops normalized test year operating results using expenses, revenues, and billing determinants that are representative of operations on a going forward basis. Because the revenues, expenses, and billing determinants have been fully normalized in this proceeding all three have been fully synchronized.

The Company has historically removed the unbilled revenues in the calculation of rates as approved in KU's last base rate case, Case No. 2003-00434, and LG&E's last base rate case, Case No. 2003-00433, as well as LG&E's Case No. 2000-080 and Case No. 90-158. Accrued expenses were not removed in any of these cases.

In its Order in Case No. 2003-00433, the Commission recognized that "the revenues eliminated by LG&E's adjustment included the recovery of environmental surcharge, fuel clause, and demand-side management costs that are removed from test-year operating results through various other adjustments". In that case, as in this one, the Company proposed adjustments for those and other factors that impact the calculation of unbilled revenues, such as changes in the number of customers, to properly normalize for those factors. In its Order, the Commission indicated that any mismatch "is adequately mitigated by the various normalization adjustments included in its rate application". Since the Company made similar adjustments in this case and such adjustments were agreed to by the Commission in the last case, the Company did not propose to remove "unbilled expenses" from test year operations following the removal of the unbilled revenues.

c. The Company's revenue is categorized based on the balance sheet classification of the revenue transaction. ***Billed revenue*** represents transactions billed through the Company's CIS and is posted as a receivable to FERC account 142. ***Unbilled revenue*** represents the dollar amount of the energy delivered, but not yet billed during a given month as a result of the timing of the cycle billings, and is posted as a receivable to FERC account 173. The Company defines ***accrued revenues*** as accruals to eliminate the regulatory lag and over or under recovery of the various regulatory mechanisms (FAC, ECR, etc.). These accrued revenues are recorded as miscellaneous deferred debits in FERC account 186. Based on the Company's classification, unbilled revenues are separate and distinct from accrued revenues.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 4

Responding Witness: Shannon L. Charnas

Q-4. Refer to KU's response to Item 7 of Staff's Second Request. Reconcile the $26,028,000 and ($1,013,000) adjustment numbers to KU's FAC monthly filings with the Commission. If they cannot be reconciled, explain why.

A-4. The purpose of the referenced adjustments is to remove the effects of the accrual accounting treatment for the separate FAC regulatory mechanism. The amounts cannot be reconciled to each other as they are separate and distinct parts of total FAC revenue. Total FAC revenue consists of billed FAC, net unbilled FAC, accruals for the FAC regulatory lag, and over- or under-recovery as summarized below:

Billed Revenue (Ref. Sch. 1.03)		$ 116,253,633
Adjustment for Credits and Rebills		(14,045)
Net Unbilled Revenue		409,208
Accrual for Regulatory Lag	$(26,028,000)	
Accrual for Over/Under Recovery	1,013,000	
Total FAC Accrued Revenue (Ref. Sch. 1.09, line 4)		(25,015,000)
Total Revenue		$ 91,633,796

The amount in KU's FAC monthly filings represents billed FAC revenues.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 5

Responding Witness: Butch Cockerill

Q-5. Refer to KU's response to Item 25(c), (d), and (e) of Staff's Second Request. Staff requested the payments received by the 10th day of the date of the bill, the payments received between the 10th and 15th days, and payments received after the 15th day, for each rate class, as a percentage of actual billings for each month. It appears that KU has provided the information for each rate class as a percentage of total actual billings for all classes. Provide the information for each class as a percentage of total actual billings for each class (i.e., each row of percentages should equal 100 percent).

A-5. See attached. Percentages will not necessarily add to 100% for each row because a late payment made as part of a subsequent bill is treated as payment only of the subsequent bill.

Month	Rate Class	Payments as a % of Total Actual Billings for Each Class		
		Received by the 10th day	Received between the 10th and 15th day	Received after the 15th day
May-07	COMMERCIAL-L-P	45%	31%	13%
	INDUSTRIAL-L-P	47%	27%	14%
	MINE-POWER	56%	24%	10%
	MUNICIPAL-PUMP	76%	13%	7%
	OTHER-PUB-AUTH	74%	14%	8%
	PUBLIC-STREET	81%	10%	5%
	RESIDENTIAL	40%	30%	16%
Jun-07	COMMERCIAL-L-P	48%	32%	14%
	INDUSTRIAL-L-P	48%	31%	15%
	MINE-POWER	46%	29%	20%
	MUNICIPAL-PUMP	78%	11%	7%
	OTHER-PUB-AUTH	76%	14%	8%
	PUBLIC-STREET	84%	10%	4%
	RESIDENTIAL	42%	31%	17%
Jul-07	COMMERCIAL-L-P	48%	32%	13%
	INDUSTRIAL-L-P	48%	30%	16%
	MINE-POWER	48%	26%	18%
	MUNICIPAL-PUMP	78%	14%	6%
	OTHER-PUB-AUTH	74%	16%	7%
	PUBLIC-STREET	85%	8%	4%
	RESIDENTIAL	43%	31%	16%
Aug-07	COMMERCIAL-L-P	35%	37%	21%
	INDUSTRIAL-L-P	33%	36%	25%
	MINE-POWER	39%	23%	31%
	MUNICIPAL-PUMP	73%	12%	11%
	OTHER-PUB-AUTH	67%	16%	14%
	PUBLIC-STREET	77%	9%	11%
	RESIDENTIAL	35%	34%	21%
Sep-07	COMMERCIAL-L-P	35%	36%	22%
	INDUSTRIAL-L-P	33%	32%	26%
	MINE-POWER	40%	22%	31%
	MUNICIPAL-PUMP	69%	16%	10%
	OTHER-PUB-AUTH	66%	16%	14%
	PUBLIC-STREET	79%	8%	9%
	RESIDENTIAL	36%	34%	19%

		Payments as a % of Total Actual Billings for Each Class		
Month	Rate Class	Received by the 10th day	Received between the 10th and 15th day	Received after the 15th day
Oct-07	COMMERCIAL-L-P	37%	36%	20%
	INDUSTRIAL-L-P	36%	32%	25%
	MINE-POWER	42%	24%	23%
	MUNICIPAL-PUMP	74%	13%	10%
	OTHER-PUB-AUTH	69%	16%	12%
	PUBLIC-STREET	80%	11%	7%
	RESIDENTIAL	37%	34%	18%
Nov-07	COMMERCIAL-L-P	32%	36%	25%
	INDUSTRIAL-L-P	31%	30%	32%
	MINE-POWER	41%	17%	34%
	MUNICIPAL-PUMP	70%	13%	15%
	OTHER-PUB-AUTH	65%	16%	17%
	PUBLIC-STREET	77%	10%	10%
	RESIDENTIAL	34%	33%	22%
Dec-07	COMMERCIAL-L-P	34%	32%	27%
	INDUSTRIAL-L-P	36%	31%	27%
	MINE-POWER	45%	20%	29%
	MUNICIPAL-PUMP	72%	10%	15%
	OTHER-PUB-AUTH	65%	15%	17%
	PUBLIC-STREET	76%	10%	11%
	RESIDENTIAL	34%	29%	27%
Jan-08	COMMERCIAL-L-P	39%	36%	18%
	INDUSTRIAL-L-P	34%	36%	23%
	MINE-POWER	47%	29%	15%
	MUNICIPAL-PUMP	75%	13%	10%
	OTHER-PUB-AUTH	68%	15%	13%
	PUBLIC-STREET	78%	11%	8%
	RESIDENTIAL	39%	33%	19%
Feb-08	COMMERCIAL-L-P	40%	36%	17%
	INDUSTRIAL-L-P	37%	34%	23%
	MINE-POWER	44%	30%	16%
	MUNICIPAL-PUMP	75%	16%	8%
	OTHER-PUB-AUTH	69%	17%	12%
	PUBLIC-STREET	79%	12%	7%
	RESIDENTIAL	40%	34%	17%

		Payments as a % of Total Actual Billings for Each Class		
Month	Rate Class	Received by the 10th day	Received between the 10th and 15th day	Received after the 15th day
Mar-08	COMMERCIAL-L-P	41%	36%	16%
	INDUSTRIAL-L-P	36%	37%	20%
	MINE-POWER	43%	30%	20%
	MUNICIPAL-PUMP	72%	20%	4%
	OTHER-PUB-AUTH	70%	18%	9%
	PUBLIC-STREET	79%	11%	6%
	RESIDENTIAL	39%	33%	18%
Apr-08	COMMERCIAL-L-P	41%	37%	16%
	INDUSTRIAL-L-P	39%	37%	17%
	MINE-POWER	47%	33%	8%
	MUNICIPAL-PUMP	77%	13%	8%
	OTHER-PUB-AUTH	70%	18%	9%
	PUBLIC-STREET	79%	12%	6%
	RESIDENTIAL	40%	33%	17%

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 6

Responding Witness: Butch Cockerill

Q-6. Refer to KU's response to Staffs Second Request, Item 29. This response shows only labor costs in the calculation of the $12.22 service order cost. Does this mean that no transportation, supplies, and equipment costs are included?

A-6. KU's proposed cost of $12.22 includes Company labor and all associated contractor costs necessary to complete service orders related to disconnection and reconnection of customer's service. The cost does not include the Company's expense for transportation, supplies, and equipment. These costs were inadvertently omitted from our initial calculations. However, the contractor costs include labor, transportation, overhead, and profit. The contractor's cost to provide this service is established through a competitive bid process.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 7

Responding Witness: William Steven Seelye

Q-7. Refer to KU's response to Item 34 of Staff's Second Request. Provide the resulting proposed rates for the lighting customer classes if KU had limited the proposed increases to the rate classes within the lighting group that were not earning a sufficient rate of return.

A-7. One of the reasons that KU is proposing an increase for Private Outdoor Lighting – POL and Customer Outdoor Lighting – OL is that the risk of equipment loss is higher for lighting service than standard utility service. However, if KU had limited the proposed increases to Street Lighting – SL and Decorative Street Lighting – SLDEC, and had not increased Private Outdoor Lighting – POL and Customer Outdoor Lighting – OL, the Company would not only have proposed larger increases to Street Lighting – SL and Decorative Street Lighting – SLDEC but would have also proposed a larger increase to Residential – RS and All Electric School Service Rate – AES. Specifically, KU would have increased all of these rates by approximately the same percentage. Attached is a version of Seelye Exhibit 4 and Seelye Exhibit 5 reallocating the revenues as requested to show the rates had KU not proposed to increase Private Outdoor Lighting – POL and Customer Outdoor Lighting – OL.

KENTUCKY UTILITIES COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended April 30, 2008

	Revenue Adjusted to as Billed Basis	Adjustment to Remove ECR Billings	Adjustment to Remove DSM Billings	Adjustment to Remove Merger Surcredit Billings	Adjustment to Remove Value Delivery Surcredit	Adjustment to Reflect a Full Year of Base Rate Changes for FAC Rollin	Adjustment to Reflect FAC Billings for Full Year of the Rollin	Adjustment to Reflect Full Year of Base Rate Changes for ECR Rollin	Adjustment Reflecting Year-End Number of Customers	Adjustment Reflecting Customer Rate Switching during Test Year	Adjustment Reflecting Temperature Normalization	Adjusted Billings at Current Rates
Total Residential	419,658,185	(20,625,999)	(3,999,568)	6,931,759	1,281,117	26,969,802	(26,968,415)	8,317,267	843,080		(6,924,469)	405,482,758
General Service Rate GS - Secondary	136,859,057	(6,655,712)	(123,092)	2,258,368	416,427	8,173,074	(8,163,701)	2,660,581	1,130,662		(1,002,779)	135,552,885
General Service Rate GS - Primary	3,021,555	(150,004)	(2,670)	50,423	9,403	164,763	(198,343)	71,094	(40,127)			2,926,095
Total General Service	139,880,612	(6,805,716)	(125,762)	2,308,790	425,830	8,337,838	(8,362,043)	2,731,675	1,090,535		(1,002,779)	138,478,980
All Electric School Service Rate - AES	7,663,579	(375,761)	-	125,127	23,364	545,922	(545,878)	155,692	-			7,592,045
Large Power Rate LPS - Secondary	217,223,215	(10,481,169)	(240,135)	3,549,075	660,193	18,252,448	(18,201,574)	4,461,707	(6,373,654)		(565,554)	208,284,552
Large Power Rate LPP - Primary	83,319,658	(4,017,666)	(45,915)	1,260,029	253,206	7,774,251	(7,768,615)	1,608,542	-		(195,804)	82,187,686
Large Power Rate LPT - Transmission	1,313,122	(63,713)	(2,128)	21,533	3,988	118,293	(118,292)	25,729				1,298,531
Small Time-of-Day - STODS Secondary	9,082,582	(439,535)	(15,427)	149,681	27,621	889,347	(916,875)	150,385			(32,622)	8,895,156
Small Time-of-Day - STODP Primary	729,069	(35,498)	(215)	11,935	2,222	69,199	(71,871)	11,395				716,236
Small Time-of-Day - STODT Transmission	-			-				-				-
Total Combined Lighting & Power Service	311,667,645	(15,037,581)	(303,820)	4,992,254	947,229	27,103,538	(27,077,227)	6,257,758	(6,373,654)	-	(793,981)	301,382,162
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	129,809,288	(6,234,214)		1,535,989	394,429	12,980,212	(12,959,017)	2,520,001			-	128,046,688
Large Comm /Industrial Time-of-Day - LCI-TOD Transmission	39,511,303	(1,899,790)	-	460,770	120,177	3,739,483	(3,738,335)	772,635				38,966,242
Curtailable Service Riders - Primary - LCI -TOD Primary	(96,313)	-	-	-				-				(96,313)
Curtailable Service Riders - Transmission -LCI-TOD Transmission	(5,446,292)	-	-				-					(5,446,292)
Total Comm /Industrial Time-of-Day Service	163,777,986	(8,134,004)	-	1,996,759	514,605	16,719,695	(16,697,352)	3,292,636	-			161,470,325
Large Industrial Time of Day - LITOD	22,399,707	(1,074,397)	-	365,961	68,105	1,605,452	(1,605,452)	199,393	-			21,958,768
Coal Mining Power Service Rate - MP Primary	6,647,736	(322,307)	-	108,485	20,228	478,023	(451,324)	151,877	215,149			6,847,866
Coal Mining Power Service Rate - MP Transmission	3,858,666	(185,612)		63,911	11,701	316,330	(305,597)	80,508	-			3,839,906
Total Coal Mining Power Service	10,506,402	(507,920)		172,396	31,929	794,353	(756,922)	232,385	215,149	-		10,687,772
Large Mine Power Time-of-Day Rate - LMP-TOD Primary	4,738,075	(226,784)		77,434	14,392	392,964	(392,865)	113,845	-			4,717,063
Large Mine Power Time-of-Day Rate - LMP-TOD Transmission	13,387,918	(653,513)	-	218,899	40,804	1,166,482	(1,169,016)	296,131	-			13,287,705
Total Large Mine Power Time-of-Day Service	18,125,994	(880,296)		296,333	55,196	1,559,446	(1,561,881)	409,976	-			18,004,768
Street Lighting - SL	7,312,070	(351,684)	-	120,138	22,193	192,583	(178,863)	131,336	5,438		-	7,253,212
Decorative Street Lighting - SLDEC	1,378,194	(62,946)	-	23,165	4,259	19,268	(14,694)	24,162	(87,075)			1,284,334
Private Outdoor Lighting - POL	4,076,501	(196,490)	-	66,864	12,408	142,318	(133,089)	74,198	65,957			4,108,667
Customer Outdoor Lighting - OL	6,015,216	(289,759)		98,990	19,315	214,873	(205,005)	109,176	(2,475)			5,960,330
Total Private Outdoor Lighting Service	18,781,981	(900,879)	-	309,157	58,175	569,042	(531,650)	338,872	(18,155)		-	18,606,543
TOTAL ULTIMATE CONSUMERS	$ 1,112,462,089	$ (54,342,552)	$ (4,429,149)	$ 17,498,536	$ 3,405,550	$ 84,205,087	$ (84,106,820)	$ 21,935,653	$ (4,243,045)	$ -	$ (8,721,229)	$ 1,083,664,121
Miscellaneous Service Revenue	6,158,810											6,158,810
TOTAL JURISDICTIONAL	$ 1,118,620,900	$ (54,342,552)	$ (4,429,149)	$ 17,498,536	$ 3,405,550	$ 84,205,087	$ (84,106,820)	$ 21,935,653	$ (4,243,045)	$ -	$ (8,721,229)	$ 1,089,822,931

KENTUCKY UTILITIES COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended April 30, 2008

	Adjusted Billings at Current Rates (see page 1)	Increase	Percentage Increase
Total Residential	405,482,758	17,726,591	4.37%
General Service Rate GS - Secondary	135,552,885		
General Service Rate GS - Primary	2,926,095	446,784	15.27%
Total General Service	138,478,980	446,784	0.32%
All Electric School Service Rate - AES	7,592,045	333,813	4.40%
Large Power Rate LPS - Secondary	208,284,552		
Large Power Rate LPP - Primary	82,187,686		
Large Power Rate LPT - Transmission	1,298,531	(70,621)	
Small Time-of-Day - STODS Secondary	8,895,156	82,070	0.92%
Small Time-of-Day - STODP Primary	716,236	6,637	0.93%
Small Time-of-Day - STODT Transmission			
Total Combined Lighting & Power Service	301,382,162	18,086	0.01%
Large Comm /Industrial Time-of-Day - LCI-TOD Primary	128,046,688		
Large Comm /Industrial Time-of-Day - LCI-TOD Transmission	38,966,242	(38,022)	
Curtailable Service Riders - Primary - LCI -TOD Primary	(96,313)		
Curtailable Service Riders - Transmission -LCI-TOD Transmission	(5,446,292)		
Total Comm /Industrial Time-of-Day Service	161,470,325	(38,022)	
Large Industrial Time of Day - LITOD	21,958,768		
Coal Mining Power Service Rate - MP Primary	6,847,866	575,463	8.40%
Coal Mining Power Service Rate - MP Transmission	3,839,906	100,123	2.61%
Total Coal Mining Power Service	10,687,772	675,586	6.32%
Large Mine Power Time-of-Day Rate - LMP-TOD Primary	4,717,063	29,196	0.62%
Large Mine Power Time-of-Day Rate - LMP-TOD Transmission	*13,287,705*	*5,099*	*0.04%*
Total Large Mine Power Time-of-Day Service	18,004,768	34,295	0.19%
Street Lighting - SL	7,253,212	312,954	4.31%
Decorative Street Lighting - SLDEC	1,284,334	63,324	4.93%
Private Outdoor Lighting - POL	4,108,667		0.00%
Customer Outdoor Lighting - OL	5,960,330		0.00%
Total Private Outdoor Lighting Service	18,606,543	376,278	2.02%
TOTAL ULTIMATE CONSUMERS	$ 1,083,664,121	19,573,411	1.81%
Miscellaneous Service Revenue	6,158,810	2,536,008	
TOTAL JURISDICTIONAL	1,089,822,931	22,109,419	2.03%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RS - Rate Codes 010, 050						
Customer Charges	2,670,330		$ 5.00	$ 13,351,650	$ 8.57	22,884,728
All Energy		3,031,975,597	$ 0.05774	175,066,271	$ 0.05774	175,066,271
Minimum Energy				3,908		4,106
Total Calculated at Base Rates				$ 188,421,829		$ 197,955,105
Correction Factor				1.0000000		1.000000
Total After Application of Correction Factor				$ 188,421,833		$ 197,955,109
Fuel Clause Billings - proforma for rollin				4,859,674		4,859,674
Adjustment to Reflect Year-End Customers				(550,029)		(577,858)
Adjustment to Reflect Temperature Normalization				(4,501,179)		(4,501,179)
Total				$ 188,230,299		$ 197,735,746
Proposed Increase						9,505,447
Percentage Increase						5.05%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) Bills	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
RS - Rate Codes 020, 060, 080						
Customer Charges	2,287,781		$ 5.00	$ 11,438,905	$ 8.57	19,606,283
All Energy		3,465,833,654	$ 0.05774	200,117,235	$ 0.05774	200,117,235
Minimum Energy				(426)		(442)
Total Calculated at Base Rates				$ 211,555,715		$ 219,723,076
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 211,555,693		$ 219,723,054
Fuel Clause Billings - proforma for rollin				6,726,947		6,726,947
Adjustment to Reflect Year-End Customers				1,393,109		1,446,892
Adjustment to Reflect Temperature Normalization				(2,423,290)		(2,423,290)
Total				$ 217,252,459		$ 225,473,603
Proposed Increase						8,221,144
Percentage Increase						3.78%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)		(4)		(5)		(6)		(7)
	Bills	Total KWH		Present Rates		Calculated Revenue at Present Rates		Proposed Rates		Calculated Revenue at Proposed Rates
GSS - Rate Codes 110, 113, 150, 153, 710										
Customer Charges	938,420		$	10.00	$	9,384,200	$	10.00		9,384,200
All KWH		1,819,611,111	$	0.06745		122,732,769	$	0.06745		122,732,769
Minimum Energy						197,073				197,073
Total Calculated at Base Rates					$	132,314,043			$	132,314,043
Correction Factor						1.000005				1.000005
Total After Application of Correction Factor					$	132,313,364			$	132,313,364
Fuel Clause Billings - proforma for rolling						3,111,638				3,111,638
Adjustment to Reflect Year-End Customers						1,130,662				1,130,662
Adjustment to Reflect Temperature Normalization						(1,002,779)				(1,002,779)
Total					$	135,552,885			$	135,552,885
Proposed Increase										-
	Percentage Increase									0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
GSP - Rate Codes 111, 151 (Customers to be Served Under Rate PS)						
Customer Charges	872		$ 10.00	$ 8,720	$ 75.00	65,400
All KWH		43,720,684	$ 0.06745	2,948,960	$ 0.03282	1,434,913
Minimum Energy				81,888		90,045
Demand (KW)	241,323				7.26	1,752,004
Demand Discount				(150,182)		-
Total Calculated at Base Rates				$ 2,889,386		$ 3,342,361
Correction Factor				0.999780		0.999780
Total After Application of Correction Factor				$ 2,890,020		$ 3,343,095
Fuel Clause Billings - proforma for rollin				76,202		76,202
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(40,127)		(46,418)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 2,926,095		3,372,879
Proposed Increase						446,784
Percentage Increase						15.27%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
AES - Rate Code 220						
Number of Customers	3,668					
All KWH		131,931,925	$ 0.05571	$ 7,349,928	$ 0.05824	7,683,715
Minimum Energy				559		585
Total Calculated at Base Rates				$ 7,350,487.00		7,684,300
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 7,350,487		$ 7,684,300
Fuel Clause Billings - proforma for rollin				241,558		241,558
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 7,592,045		$ 7,925,858
Proposed Increase						333,813
Percentage Increase						4.40%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills /kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LPS - Rate Codes 562, 568 (Renamed Rate PS-Secondary)						
Customer Charges	107,045		$ 75.00	$ 8,028,375	$ 75.00	$ 8,028,375
Demand (KW)	9,890,858		$ 7.65	75,665,061	$ 7.65	75,665,061
Minimum Demand Charges				486,832		486,832
All KWH		3,797,009,283	$ 0.03282	124,617,845	$ 0.03282	124,617,845
Minimum Energy				19,525		19,525
Total Calculated at Base Rates				$ 208,817,638		$ 208,817,638
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 208,817,741		$ 208,817,741
Fuel Clause Billings - proforma for rollin				6,178,202		6,178,202
STOD Billings				227,817		227,817
Adjustment to Reflect Year-End Customers				(6,373,654)		(6,373,654)
Adjustment to Reflect Temperature Normalization				(565,554)		(565,554)
Total				$ 208,284,552		$ 208,284,552
Proposed Increase						
	Percentage Increase					0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LPP - Rate Codes 561, 566 (Renamed Rate PS-Primary)						
Customer Charges	4,202		$ 75.00	$ 315,150	$ 75.00	315,150
Demand (KW)	3,572,354		$ 7.26	25,935,289	$ 7.26	25,935,289
Minimum Demand Charges				70,488		70,488
All KWH		1,624,875,433	$ 0.03282	53,328,412	$ 0.03282	53,328,412
Minimum Energy				(21,897)		(21,897)
Total Calculated at Base Rates				$ 79,627,441		$ 79,627,441
Correction Factor				0.999999		0.999999
Total After Application of Correction Factor				$ 79,627,495		$ 79,627,495
Fuel Clause Billings - proforma for rollin				2,658,502		2,658,502
STOD Billings				97,494		97,494
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				(195,804)		(195,804)
Total				$ 82,187,686		$ 82,187,686
Proposed Increase						-
	Percentage Increase					0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LPT - Rate Codes 560, 567 (Customers to be Served Under Rate RTS)						
Customer Charges	24		$ 75.00	$ 1,800	$ 120.00	2,880
Demand (KW)	57,176		$ 6.92	395,659		
On-Peak Demand (KVA)	60,593				$ 4.39	266,002
Off-Peak Demand (KVA)	58,217				$ 1.13	65,786
Minimum Demand Charges				-		-
All KWH		26,100,266	$ 0.03282	856,611	$ 0.03252	848,781
Minimum Energy				-		-
Total Calculated at Base Rates				$ 1,254,069		$ 1,183,448
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 1,254,069		$ 1,183,448
Fuel Clause Billings - proforma for rollin				42,896		42,896
STOD Billings				1,566		1,566
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 1,298,531		$ 1,227,910
Proposed Increase						(70,621)
	Percentage Increase					-5.44%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LCIP - Rate Code 563 (Renamed Rate LTOD-Primary)						
Customer Charge	466		$ 120.00	$ 55,920	$ 120.00	$ 55,920
On-Peak Demand (KW)	5,196,011		$ 5.12	26,603,575	$ 5.12	26,603,575
Off-Peak Demand (KW)	5,141,908		$ 1.27	6,530,223	$ 1.27	6,530,223
Minimum Demand				-		-
Energy		2,747,259,009	$ 0.03282	90,165,041	$ 0.03282	90,165,041
Minimum Energy				128,806		128,806
Total Calculated at Base Rates				$ 123,483,565		$ 123,483,565
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 123,483,561		$ 123,483,561
Fuel Clause Billings - proforma for rollin				4,563,128		4,563,128
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 128,046,689		$ 128,046,689
Proposed Increase						-
Percentage Increase						0.00%
CSR-1	30,098		$ (3.20)	(96,313)	(3.20)	(96,313)

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW/KVA	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LCIT - Rate Code 564 (Customers to be Served Under Rate RTS)						
Customer Charge	79		$ 120.00	$ 9,480	$ 120.00	9,480
On-Peak Demand (KW)	1,590,349		$ 4.93	$ 7,840,423		
On-Peak Demand (KVA)	1,824,495				$ 4.39	8,009,534
Off-Peak Demand (KW)	1,577,381		$ 1.27	$ 2,003,274		
Off-Peak Demand (KVA)	1,815,762				$ 1.13	2,051,811
Minimum Demand				-		-
Energy		841,958,377	$ 0.03282	27,633,074	$ 0.03252	27,380,486
Minimum Energy				11,444		8,361
Total Calculated at Base Rates				$ 37,497,694		$ 37,459,673
Correction Factor				0.999998		0.999998
Total After Application of Correction Factor				$ 37,497,758		$ 37,459,736
Fuel Clause Billings - proforma for rollin				1,468,484		1,468,484
VDT Amortization & Surcredit Adjustment				-		
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 38,966,242		$ 38,928,220
Proposed Increase						(38,022)
	Percentage Increase					-0.10%
CSR-2	1,756,868		$ (3.10)	(5,446,292)	$ (3.10)	(5,446,292)

KENTUCKY UTILITIES COMPANY

Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) Bills	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
STOD-T Rate Code 580						
Customer						
Demand						
Minimum Demand						
On Peak Energy						
Off Peak Energy						
Minimum Energy						
Total Calculated at Base Rates			**There are no customers currently served under this rate**			
Correction Factor			**All Transmission Customers must be served under RTS**			
Total After Application of Correction Factor						
Fuel Clause Billings - proforma for rollin						
VDT Amortization & Surcredit Adjustment						
Adjustment to Reflect Year-End Customers						
Adjustment to Reflect Temperature Normalization						
Total						
Proposed Increase						
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
STOD-P Rate Code 582 (Customers Eligible for Service Under Rate TOD-Primary)						
Customer	24		$ 90.00	$ 2,160	$ 120.00	2,880
Demand (KW)	26,938		$ 7.26	195,573		
On-Peak Demand (KW)	26,938				$ 6.00	161,630
Off-Peak Demand (KW)	26,658				$ 1.27	33,856
Minimum Demand				-		-
On Peak Energy		7,988,094	$ 0.03879	309,858	$ 0.03282	262,169
Off Peak Energy		7,861,106	$ 0.02596	204,074	$ 0.03282	258,002
Minimum Energy				(23,990)		(24,224)
Total Calculated at Base Rates				$ 687,675		$ 694,312
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 687,675		$ 694,312
Fuel Clause Billings - proforma for rollin				28,561		28,561
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				$ -	0.03282	-
Total				$ 716,236		$ 722,873
Proposed Increase						6,637
Percentage Increase						0.93%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
STOD-S Rate Code 584 (Customers Eligible for Service Under Rate TOD-Secondary)						
Customer	612		$ 90.00	$ 55,080	$ 90.00	55,080
Demand (KW)	351,379		$ 7.65	2,688,050		
On-Peak Demand (KW)	351,379				6.39	2,245,312
Off-Peak Demand (KW)	348,514				1.27	442,612
Minimum Demand				-		-
On Peak Energy		94,624,461	$ 0.03879	3,670,483	$ 0.03282	3,105,575
Off Peak Energy		94,679,823	$ 0.02596	2,457,888	$ 0.03282	3,107,392
Minimum Energy				(251,753)		(254,154)
Total Calculated at Base Rates				$ 8,619,748		$ 8,701,818
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 8,619,748		$ 8,701,818
Fuel Clause Billings - proforma for rollin				308,031		308,031
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				(32,622)	0.03282	(32,622)
Total				$ 8,895,156		$ 8,977,226
Proposed Increase						82,070
	Percentage Increase					0.92%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
MPP - Rate Codes 681, 686 (Customers to be Served Under Rate PS-Primary)						
Customer Charge	364		$ 75.00	$ 27,300	$ 75.00	27,300
Demand (KW)	411,206		$ 5.45	2,241,075	$ 7.26	2,985,358
Minimum demand billings				6,123		6,653
All KWH		109,956,679	$ 0.03479	3,825,393	$ 0.03282	3,608,778
Minimum energy billings				330,628		359,257
Total Calculated at Base Rates				$ 6,430,518		$ 6,987,347
Correction Factor				0.999993		0.999993
Total After Application of Correction Factor				$ 6,430,565		$ 6,987,398
Fuel Clause Billings - proforma for rollin				202,151		202,151
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				215,149		233,779
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 6,847,865		$ 7,423,328
Proposed Increase						575,463
	Percentage Increase					8.40%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) Bills / KW	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
MPT - Rate Codes 680, 687 (Customers to be Served Under Rate RTS)						
Customer Charge	123		$ 75.00	$ 9,225	$ 120.00	14,760
Demand (KW)	222,219		$ 5.33	1,184,429		
On-Peak Demand (KVA)	269,655				$ 4.39	1,183,785
Off-Peak Demand (KVA)	264,554				$ 1.13	298,946
Minimum demand billings				2,768		1,740
All KWH		69,078,000	$ 0.03479	2,403,224	$ 0.03252	2,246,417
Minimum energy billings				123,549		77,669
Total Calculated at Base Rates				$ 3,723,194		$ 3,823,317
Correction Factor				0.999999		0.999999
Total After Application of Correction Factor				$ 3,723,197		$ 3,823,320
Fuel Clause Billings - proforma for rollin				116,709		116,709
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 3,839,906		$ 3,940,029
Proposed Increase						100,123
	Percentage Increase					2.61%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LMPP - Rate Code 683 (Customers to be Served Under Rate LTOD-Primary)						
Customer Charge	39		$ 120.00	$ 4,680	$ 120.00	4,680
On-Peak Demand (KW)	271,755		$ 5.79	1,573,462	$ 5.12	1,391,386
Off-Peak Demand (KW)	264,038		$ 1.13	298,363	$ 1.27	335,328
Minimum Demand Charge				-		-
Energy		87,153,119	$ 0.03082	2,686,059	$ 0.03282	2,860,365
Minimum Energy Charge				-		-
Total Calculated at Base Rates				$ 4,562,563		$ 4,591,759
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 4,562,563		$ 4,591,759
Fuel Clause Billings - proforma for rollin				154,499		154,499
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers						-
Adjustment to Reflect Temperature Normalization						-
Total				$ 4,717,062		$ 4,746,258
Proposed Increase						29,196
	Percentage Increase					0.62%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / Kw	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LMPT - Rate Code 684 (Customers to be Served Under Rate RTS)						
Customer Charge	82		$ 120.00	$ 9,840	$ 120.00	9,840
On-Peak Demand (KW)	716,818		$ 5.25	3,763,296		
On-Peak Demand (KVA)	744,449				$ 4.39	3,268,129
Off-Peak Demand (KW)	687,441		$ 1.13	776,808		
Off-Peak Demand (KVA)	726,578				$ 1.13	821,033
Minimum Demand Charge				-		-
Energy		268,266,000	$ 0.03082	8,267,958	$ 0.03252	8,724,010
Minimum Energy Charge				-		-
Total Calculated at Base Rates				$ 12,817,902		$ 12,823,013
Correction Factor				1.002173		1.002173
Total After Application of Correction Factor				$ 12,790,113		$ 12,795,212
Fuel Clause Billings - proforma for rollin				497,592		497,592
VDT Amortization & Surcredit Adjustment				-		
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 13,287,705		$ 13,292,804
Proposed Increase						5,099
	Percentage Increase					0.04%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) Bills	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
LI-TOD Billing Code 730 (Renamed Rate IS)						
Customer Charge	12		$ 120.00	$ 1,440	$ 120.00	1,440
On-Peak Demand (KW)	1,520,293		$ 4.58	$ 6,962,943	$ 4.58	6,962,943
Off-Peak Demand (KW)	1,689,560		$ 0.93	$ 1,571,291	$ 0.93	1,571,291
Minimum Demand Charge				-		-
Energy		388,735,959	$ 0.03282	12,758,314	$ 0.03282	12,758,314
Minimum Energy Charge				-		-
	Total Calculated at Base Rates			$ 21,293,989		$ 21,293,989
	Correction Factor			1.000000		1.000000
	Total After Application of Correction Factor			$ 21,293,989		$ 21,293,989
Fuel Clause Billings - proforma for rollin				664,780		664,780
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 21,958,769		$ 21,958,769
Proposed Increase						-
	Percentage Increase					0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
Street Lighting Service Rate Schedule						
Incandescent Street Lighting						
01000L INC STD ST LT *	30,601	900	$ 2.76	$ 2,484	$ 2.76	2,484
02500L INC STD ST LT *	1,028,530	15,372	$ 3.64	55,954	$ 3.64	55,954
04000L INC STD ST LT *	500,061	4,598	$ 5.37	24,691	$ 5.37	24,691
06000L INC STD ST LT *	6,650	46	$ 7.19	331	$ 7.19	331
02500L INC ORN ST LT *	6,432	96	$ 4.48	430	$ 4.48	430
04000L INC ORN ST LT *	52,140	484	$ 6.35	3,073	$ 6.35	3,073
06000L INC ORN ST LT *	2,561	20	$ 8.28	166	$ 8.28	166
Mercury Vapor Street Lighting						
07000L MV STD ST LT	1,128,653	16,381	$ 7.73	126,625	$ 7.73	126,625
010000L MV STD ST LT	1,119,282	11,427	$ 9.12	104,214	$ 9.12	104,214
020000L MV STD ST LT	3,088,066	20,462	$ 11.13	227,742	$ 11.13	227,742
07000L MV ORN ST LT	103,502	1,500	$ 10.09	15,135	$ 10.09	15,135
010000L MV ORN ST LT	634,541	6,474	$ 11.22	72,638	$ 11.22	72,638
020000L MV ORN ST LT	2,649,502	17,555	$ 12.81	224,880	$ 12.81	224,880
High Pressure Sodium Street Lighting						
05800L HPS DEC ACORN ST LT	1,992	72	$ 11.77	847	$ 12.35	889
09500L HPS DEC ACORN ST LT	64,530	1,650	$ 12.59	20,774	$ 13.21	21,797
04000L HPS HISTORIC ACORN ST LT	35,760	1,788	$ 17.29	30,915	$ 18.15	32,452
05800L HPS HISTORIC ACORN ST LT	23,905	864	$ 17.94	15,500	$ 18.83	16,269
09500L HPS HISTORIC ACORN ST LT	188,349	4,819	$ 18.78	90,501	$ 19.71	94,982
05800L HPS POL	61,534	2,097	$ 4.86	10,191	$ 5.10	10,695
04000L HPS STD ST LT	1,685,220	84,259	$ 5.46	460,054	$ 5.73	482,804
05800L HPS STD ST LT	2,822,338	102,010	$ 6.00	612,060	$ 6.30	642,663
09500L HPS STD ST LT	9,120,054	233,717	$ 6.84	1,598,624	$ 7.18	1,678,088
022000L HPS STD ST LT	5,356,942	66,399	$ 10.36	687,894	$ 10.87	721,757
050000L HPS STD ST LT	1,599,629	9,894	$ 17.07	168,891	$ 17.91	177,202
04000L HPS ORN ST LT	943,032	47,165	$ 8.20	386,753	$ 8.61	406,091
05800L HPS ORN ST LT	2,762,804	99,823	$ 8.74	872,453	$ 9.17	915,377
09500L HPS ORN ST LT	1,278,676	32,764	$ 9.77	320,104	$ 10.25	335,831
022000L HPS ORN ST LT	4,158,893	51,518	$ 13.29	684,674	$ 13.95	718,676
050000L HPS ORN ST LT	859,382	5,316	$ 19.99	106,267	$ 20.98	111,530

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

Street Lighting Service Rate Schedule						
High Pressure Sodium Granville Configurations						
016000L GRANVILLE STLT-CONFG A	75,007	1,500	$ 40.55	60,825	$ 42.56	63,840
016000L GRANVILLE STLT-CONFG E	16,201	324	$ 65.07	21,083	$ 68.29	22,126
016000L GRANVILLE STLT-CONFG C	25,201	504	$ 44.46	22,408	$ 45.66	23,517
016000L GRANVILLE STLT-CONFG D	3,000	60	$ 46.19	2,771	$ 48.48	2,909
016000L GRANVILLE STLT-CONFG E	600	12	$ 47.39	569	$ 49.74	597
016000L GRANVILLE STLT-CONFG F	3,600	72	$ 63.09	4,542	$ 66.21	4,767
016000L GRANVILLE STLT-CONFG G	5,999	120	$ 61.36	7,363	$ 64.40	7,728
016000L GRANVILLE STLT-CONFG H	-	-	$ 45.75	-	$ 48.01	-
016000L GRANVILLE STLT-CONFG I	1,200	24	$ 41.75	1,002	$ 43.82	1,052
016000L GRANVILLE STLT-CONFG A1	9,001	180	$ 57.45	10,341	$ 60.29	10,852
016000L GRANVILLE STLT-CONFG B1	-	-	$ 81.97	-	$ 86.03	-
016000L GRANVILLE STLT-CONFG E1	600	12	$ 64.29	771	$ 67.47	810
016000L GRANVILLE STLT-CONFG A2	12,001	240	$ 57.45	13,788	$ 60.29	14,470
016000L GRANVILLE STLT-CONFG B3	2,400	48	$ 58.65	2,815	$ 61.55	2,954
016000L GRANVILLE STLT-CONFG G1	1,800	36	$ 61.36	2,209	$ 64.40	2,318
016000L GRANVILLE STLT-CONFG B2	15,603	312	$ 59.87	18,679	$ 62.83	19,603
016000L GRANVILLE STLT-CONFG A3	30,602	612	$ 48.35	29,590	$ 50.74	31,053
016000L GRANVILLE STLT-CONFG A	5,401	108	$ 40.55	4,379	$ 42.56	4,596
0107800L MH DIRECTIONAL -M POL	381,116	1,057	$ 39.32	41,561	$ 41.27	43,622
Sub-Total	41,902,893	844,691		$ 7,169,563		$ 7,482,280
Total Calculated at Base Rates				$ 7,169,563		$ 7,482,280
Correction Factor				1.000001		1.000001
Total After Application of Correction Factor				$ 7,169,559		$ 7,482,275
Fuel Clause Billings - proforma for rollin				78,214		78,214
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				5,438		5,675
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 7,253,211		$ 7,566,164
Proposed Increase						312,953
Percentage Increase						4.31%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
Street Lighting Service Rate Schedule						
Decorative						
04000L HPS COLONIAL ST LT	160,854	8,022	$ 7.40	$ 59,363	$ 7.77	$ 62,331
05800L HPS COLONIAL ST LT	309,845	11,189	$ 7.96	89,064	$ 8.35	93,428
09500L HPS COLONIAL ST LT	619,118	15,786	$ 8.71	137,496	$ 9.14	144,284
032000L MH DIRECTIONAL -M POL	388,127	2,575	$ 23.27	59,920	$ 24.42	62,882
05800L HPS CONTEMPORARY ST LT	1,260,005	57,101	$ 13.50	770,864	$ 14.17	809,121
09500L HPS CONTEMPORARY ST LT	234,286	6,647	$ 16.15	107,349	$ 16.95	112,667
022000L HPS CONTEMPORARY ST LT	445,967	6,445	$ 19.13	123,293	$ 20.08	129,416
050000L HPS CONTEMPORARY ST LT	102,820	689	$ 25.42	17,514	$ 26.68	18,383
Sub-Total	3,521,022	108,454		$ 1,364,863		$ 1,432,511
Total Calculated at Base Rates				$ 1,364,863		$ 1,432,511
Correction Factor				1.000106		1.000106
Total After Application of Correction Factor				$ 1,364,718		$ 1,432,358
Fuel Clause Billings - proforma for rollin				6,691		6,691
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(87,075)		(91,391)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 1,284,334		$ 1,347,658
Proposed Increase						63,324
Percentage Increase						4.93%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) KWH	(3) Total Lights	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
Private Outdoor Lighting						
Decorative (Served Underground)						
04000L HPS COLONIAL DEC POL	12,031	605	$ 7.40	$ 4,477	$ 7.40	$ 4,477
05800L HPS COLONIAL DEC POL	57,712	2,083	$ 7.96	16,581	$ 7.96	16,581
09500L HPS COLONIAL DEC POL	778,055	19,927	$ 8.71	173,564	$ 8.71	173,564
05800L HPS CONTEMPORARY DEC POL	16,936	612	$ 13.50	8,262	$ 13.50	8,262
09500L HPS CONTEMPORARY DEC POL	129,472	3,320	$ 16.15	53,618	$ 16.15	53,618
022000 HPS CONTEMPORARY DEC POL	621,161	7,700	$ 19.13	147,301	$ 19.13	147,301
050000 HPS CONTEMPORARY DEC POL	1,706,928	10,550	$ 25.42	268,181	$ 25.42	268,181
Directional (Served Overhead)						-
09500L HPS DIRECTIONAL POL	4,867,927	124,562	$ 6.70	834,565	$ 6.70	834,565
022000L HPS DIRECTIONAL POL	5,933,517	73,593	$ 9.79	720,475	$ 9.79	720,475
050000L HPS DIRECTIONAL POL	14,702,952	90,929	$ 15.34	1,394,851	$ 15.34	1,394,851
Metal Halide Contemporary						
012000L MH CONTEMPORARY POL	45,669	662	$ 11.17	7,395	$ 11.17	7,395
012000L MH CONTEMPORARY -M POL	143,197	2,076	$ 19.94	41,395	$ 19.94	41,395
032000L MH CONTEMPORARY POL	522,484	3,477	$ 16.13	56,084	$ 16.13	56,084
032000L MH CONTEMPORARY -M POL	979,440	6,493	$ 24.87	161,481	$ 24.87	161,481
0107800L MH CONTEMPORARY POL	207,637	584	$ 33.23	19,406	$ 33.23	19,406
0107800L MH CONTEMPORARY -M POL	652,302	1,818	$ 41.99	76,338	$ 41.99	76,338
Sub-Total	31,377,420	348,991		$ 3,983,975		$ 3,983,975
Total Calculated at Base Rates				$ 3,983,975		$ 3,983,975
Correction Factor				1.000025		1.000025
Total After Application of Correction Factor				$ 3,983,877		$ 3,983,877
Fuel Clause Billings - proforma for rollin				58,833		58,833
VDT Amortization & Surcredit Adjustment				-		
Adjustment to Reflect Year-End Customers				65,957		65,957
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 4,108,667		$ 4,108,667
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
Private Outdoor Lighting						
02500L INC COL *	-	-	$ 5.10	$ -	$ 5.10	$ -
03500L MV COL *	-	-	$ 6.23	-	$ 6.23	-
07000L MV COL *	2,484	24	$ 7.47	179	$ 7.47	179
020000L MV SPECIAL LIGHTING *	812,654	5,390	$ 6.88	37,083	$ 6.88	37,083
050000L HPS SPECIAL LIGHTING *	354,052	2,192	$ 9.18	20,123	$ 9.18	20,123
Standard (Served Overhead)						-
07000L MV POL	8,701,195	126,212	$ 8.76	1,105,617	$ 8.76	1,105,617
020000L MV POL	984,179	6,527	$ 11.13	72,646	$ 11.13	72,646
09500L HPS POL	15,623,163	399,642	$ 5.62	2,245,988	$ 5.62	2,245,988
022000L HPS POL	1,404,988	17,427	$ 10.36	180,544	$ 10.36	180,544
050000L HPS POL	4,231,587	26,167	$ 17.07	446,671	$ 17.07	446,671
Decorative (Served Underground)						-
04000L HPS DEC ACORN D/D POL	477	24	$ 11.11	267	$ 11.11	267
05800L HPS DEC ACORN D/D POL	13,568	490	$ 11.77	5,767	$ 11.77	5,767
09500L HPS DEC ACORN D/D POL	113,943	2,913	$ 12.61	36,733	$ 12.61	36,733
04000L HPS HIST ACORN D/D POL	14,641	732	$ -	-		-
05800L HPS HIST ACORN D/D POL	24,675	892	$ 17.29	15,423	$ 17.29	15,423
09500L HPS HIST ACORN D/D POL	255,935	6,549	$ 18.78	122,990	$ 18.78	122,990
05800L HPS COACH DEC POL	7,969	288	$ 26.62	7,667	$ 26.62	7,667
09500L HPS COACH DEC POL	121,707	3,120	$ 27.36	85,363	$ 27.36	85,363
05800L HPS COACH DEC POL	6,972	252	$ 26.62	6,708	$ 26.62	6,708
09500L HPS COACH DEC POL	4,681	120	$ 27.36	3,283	$ 27.36	3,283
Metal Halide Directional						-
012000L MH DIRECTIONAL POL	414,824	6,001	$ 10.03	60,190	$ 10.03	60,190
012000L MH DIRECTIONAL -W POL	98,345	1,425	$ 12.08	17,214	$ 12.08	17,214
012000L MH DIRECTIONAL -M POL	9,172	133	$ 18.78	2,498	$ 18.78	2,498
032000L MH DIRECTIONAL POL	6,984,958	46,496	$ 14.52	675,122	$ 14.52	675,122
032000L MH DIRECTIONAL -W POL	1,459,773	9,730	$ 16.58	161,323	$ 16.58	161,323
0107800L MH DIRECTIONAL POL	5,071,356	14,106	$ 30.58	431,361	$ 30.58	431,361
0107800L MH DIRECTIONAL -W POL	1,281,044	3,572	$ 33.43	119,412	$ 33.43	119,412
Sub-Total	47,998,342	123,010		$ 5,860,172		$ 5,860,172
Total Calculated at Base Rates				$ 5,860,172		$ 5,860,172
Correction Factor				0.997705		0.997705
Total After Application of Correction Factor				$ 5,873,653		$ 5,873,653
Fuel Clause Billings - proforma for rollin				89,152		89,152
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(2,475)		(2,475)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 5,960,330		$ 5,960,330
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 8

Responding Witness: William Steven Seelye

Q-8. Refer to KU's response to Item 35 of Staff's Second Request, page 1 of 2. Reconcile the Revenue Adjusted to As-Billed Basis of $1,112,462,089 in column 1 with the Jurisdictional Ultimate Consumer Revenue of $1,111,405,132 shown on William S. Seelye Exhibit 6, page 8.

A-8. The Jurisdictional Ultimate Consumer Revenue of $1,111,405,132 shown on Seelye Exhibit 6, page 8, includes (i) an amortization of a lump-sum merger surcredit amount of -$1,069,895, (ii) Tennessee jurisdictional revenues of $2,280, and (iii) redundant capacity charge revenues of $10,655. When these three items are backed out of the $1,111,405,132 amount shown on Seelye Exhibit 6, page 8, the amount is reconciled to the Revenue Adjusted to As-Billed Basis of $1,112,462,089. Because these three items do not correspond to billing amounts to which a late payment charge would be applicable, the Revenue Adjusted to As-Billed Basis of $1,112,462,089 would be the more appropriate revenue amount to be used in line 1 of Seelye Exhibit 6, page 8. Attached is the revised exhibit using $1,112,462,089 rather than $1,111,405,132.

KENTUCKY UTILITIES

Adjustment to Revenues for Estimated Late Payment Charge
For the Twelve Months Ended April 30, 2008

1	Jurisdictional Ultimate Consumer Revenue		$ 1,112,462,089
2	Louisville Gas and Electric Company Late Payment Charges (LPC) as a percent of Ultimate Consumer Revenues (a)	0 3026%	
3	Determination of weight of Louisville Gas and Electric Company's LPC to apply to Kentucky Utilities' customers		
4	Estimated Late Payment Charge equal to LG&E	100 0000%	
5	Five year avearge Kentucky Utilities Net Charge-Offs as a percentage of Louisville Gas and Electric Company's Net Charge-Offs (b)	41 9366%	
6	Five year avearge Kentucky Utilities A/R as a percentage of Louisville Gas and Electric Company's A/R (c)	59 9294%	
7	Average weight (average of Line No 4 through Line No 6)	67 2887%	
8	Kentucky Utilities Estimated Late Payment Charge as a percent of Ultimate Consumer Revenue Line No 2 x Line No 7		0.2036%
9	Kentucky Jurisdictional adjustment (Line No 1 x Line No 8)		2,264,841

(a) Estimated percentage is based on 5 year average actual LG&E Electric Late Payment Charge to LG&E Electric Utlimate Consumer Revenue

	LG&E Ultimate Consumer Billed Electric Revenue ($000)	Forfeited Discounts ($000)	LG&E Forfeited Discounts as a percentage of Ultimate Consumer Billed Electric Revenues
2007	759,840	2,581	0 3397%
2006	693,392	2,120	0 3058%
2005	682,659	2,009	0 2943%
2004	619,480	1,723	0 2782%
2003	578,179	1,652	0.2858%
5 Year Average	666,710	2,017	0 3026%

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 9

Responding Witness: William Steven Seelye

Q-9. Refer to KU's response to Staffs Second Request, Item 66.

a. Explain why the number of RS customers (Rate Code 010, 050) spiked in January 2008.

b. The number of Street Lighting - SL customers ranged between 70,071 and 70,585 during the 13-month period, except for April 2007, when it was 72,206. Explain why the number of customers in April 2007 is so much larger than the number of customers during the 13-month period.

c. The number of Decorative Street Lighting - SLDEC customers ranged between 7,673 and 8,206 during the 13-month period, except for April and May 2007, when it was 5,627 and 20,853, respectively. Explain the fluctuations for April and May 2007.

A-9. a. KU does not track the reasons that customers enter or leave its service territory. Changes in the number of customers from month to month can be the result of a number of factors, including but not limited to the examples provided below. Fluctuations in customer counts can result from customer movement out of the territory and receiving a final bill in the following month, and customers entering the service territory and receiving an initial bill in the same calendar month. Additionally, fluctuations can occur by the closing and opening of businesses or residential customers' buying and selling homes within the Company's service territory. Furthermore, fluctuations also occur because of seasonal customers' terminating service during periods when service is not needed and reconnecting when service is again needed. Fluctuations in customer counts can also result from billing adjustments made in a current month for activity in previous months.

b. and c.
These fluctuations are the result of billing adjustments that are reflected in the Company's revenue reports for May 2007. KU discovered an error in the coding of certain light fixtures installed for Lexington Fayette Urban County

Government in its revenue reports, whereby some fixtures were erroneously classified as Street Light fixtures rather than Decorative Street Light fixtures. The coding was corrected and the customer's bills were corrected in May 2007, resulting in a one-time increase in SLDEC fixtures and an on-going decrease in SL fixtures. These billings adjustments were reflected in the Company's revenue reports. These revenue reports were used to calculate the year-end adjustment and to develop the test-year billing determinants shown in Seelye Exhibit 5.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 10

Responding Witness: Valerie L. Scott

Q-10. Refer to KU's response to Item 3 of the AG's Initial Request for Information. Provide the origin of the $1,169,688,236 shown as "Billed revenues from ultimate customers for the twelve months ended 04/30/08."

A-10. KU's billed revenues from ultimate customers come from the Company's Customer Information System. This system provides the billed revenue amounts distributed by different revenue classes, such as residential, commercial, and public authority. Also, the revenue is separated by revenue components, such as customer charges, demand charges, DSM, and ECR.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 11

Responding Witness: Shannon L. Charnas

Q-11. Refer to KU's response to Item 18(c) of the AG's Initial Request for Information and KU's response to Item 7(a) of KIUC's First Data Request. Both of these responses show that no FAC revenues were recorded as a part of unbilled revenues at April 30, 2007.

a. Provide the amount of unbilled FAC revenues at April 30, 2007.

b. Explain why excluding the April 30, 2007 unbilled FAC revenues from the total April 30, 2007 unbilled revenue results in an accurate adjustment to test year revenue for unbilled revenues.

A-11. a. There was no FAC revenue reported as unbilled in April 2007.

b. Prior to the fourth quarter of 2007, FAC revenue that was not yet billed through the Company's Customer Information System was included in accrued FAC. In the fourth quarter of 2007, to enhance the analysis of operations, FAC revenue was further differentiated into unbilled FAC, FAC accrued for the regulatory lag, and the accrual for the over- or under-recovery of FAC. The net effect of this change was that FAC revenue was included in unbilled revenue at April 30, 2008, while FAC revenue was included in accrued revenue at April 30, 2007. Please note, however, that all FAC revenues have been removed from test year operating results in this and previous rate proceedings, consistent with Commission practice.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 12

Responding Witness: Butch Cockerill / Robert M. Conroy

Q-12. Refer to KU's response to Item 16 of the Lexington-Fayette Urban County Government's Initial Request for Information. Page 2 of 2, line 84, shows a "Meter Pulse Charge." Provide the location of this charge in KU's tariff and explain how it relates to the meter pulse charge being proposed in this case.

A-12. The meter pulse charge listed in response to item No. 16 should not be listed as a rate class and is not a tariffed item. It is billed according to a contractual agreement between the customer and the Company. In an effort to harmonize charges between the Company and its sister company Louisville Gas and Electric Company, a move to standardize pricing and place meter pulse charges on the tariff of both companies has been proposed in this case.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 13

Responding Witness: William E. Avera

Q-13. Refer to page 24 of William Avera's original Testimony, to Schedule 1 of KU's attachment to the supplemental response to Item 14 of Staff's Second Request, and to Item 15 of Staff's Second Request. There appear to be significant differences between KU and many of the firms that are included as proxies for KU in the analysis.

a. Eight of the firms in the proxy group own and operate nuclear power generation facilities, while KU does not. Explain why this should not be a factor in rejecting these firms as appropriate for inclusion in the proxy group.

b. Allete, Alliant Energy, Integrys Energy, Scana Corporation, and Vectren Corporation are all mid-cap companies, as reported by Value Line. All others in the proxy group are large-cap companies. Explain how these large companies are appropriately included in the proxy group.

c. Refer to KU's response to Item 136 of Staffs Second Request wherein KU provides a discussion of its target capital structure. Allete, Alliant Energy, Constellation Energy, Duke Energy, Integrys Energy, MDU Resources, and Sempra Energy have debt-to-capital ratios of less than 35 percent. Only Dominion Resources, Exelon Corporation, Vectren Corporation, and Wisconsin Energy have debt-to-capital ratios greater than 50 percent.

(1) Explain why firms with capital structures so far out of line with KU's should be included in the proxy group

(2) For each company in the proxy group, including KU, provide the percentage of 2007 revenues derived from (i) non-utility sources, (ii) utility operations subject to price regulation by a state commission; and (iii) utility operations not subject to price regulation by a state commission.

A-13. a. Each firm in the Utility Proxy Group has comparable risk based on objective measures of investors' risk assessments. As explained on pages 23-24 of Dr.

Avera's direct testimony, in order to reflect the risks and prospects associated with KU's jurisdictional utility operations, the proxy group companies were those included by *The Value Line Investment Survey* ("Value Line") in its Electric Utilities Industry groups with: (1) both electric and gas utility operations, (2) S&P corporate credit ratings between "BBB" and "A"; (2) a Value Line Safety Rank of "3" or better; and (3) a Value Line Financial Strength Rating of "B++" or better. Credit ratings are assigned by independent rating agencies to provide investors with a broad assessment of the creditworthiness of a firm. Because the rating agencies' evaluations include virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors as objective measures of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity.

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank and Financial Strength Rating provide useful guidance regarding the risk perceptions of investors. The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps.

KU is rated "BBB+" by S&P, which is identical to the average for the utilities in the Utility Proxy Group. Meanwhile, the average Value Line Safety Rank and Financial Strength Rating for the Utility Proxy Group is "2" and "A", respectively. These two benchmarks indicate that the risks associated with an equity investment in the Utility Proxy Group are conservative and in-line with those generally associated with a "BBB+" credit.

Within the Utility Proxy Group, individual companies may differ with respect to the specific characteristics noted in parts a, b, c (1) above. Yet it is reasonable to consider that taken as a whole, these companies are comparable in investment risk to KU based on objective, published indicators that incorporate consideration of a broad spectrum of risks, including nuclear generation, capitalization size, debt to total capital, and consideration of other company specific factors. For example, nuclear generation has characteristics that investors regard as contributing to investment risk such as exposure to federal regulations regarding safety, spent fuel treatment, homeland security measures, high capital costs, and technical complexity, while there are other features that decrease risk such as low relative fuel costs, limited exposure to fuel transportation disruptions or cost, environmental exposure, and use of carbon fuel. While KU does not have nuclear exposure, its dependence upon coal has risks in the perception of investors as documented on pages 15-16 of Dr. Avera's direct testimony. When all of the characteristics of the eight companies with nuclear exposure in the Utility Proxy Group are considered, the end-result is that objective measures of investors' risk assessment position these companies as comparable in risk to KU considering its concentration of coal generation and all of its other characteristics.

b. See response to 13(a) above. Size can affect investor risk perceptions. The companies in the Utility Proxy Group vary in size from mid-capitalization to large capitalization as classified by Value Line. When all of the characteristics of the companies in the Utility Group are considered in the objective measures of risk reported the end-result is that they are rated comparable to KU.

c. (1) See response to 13(a) above. The capital structures of the companies in the Utility Proxy Group are one factor considered in the overall objective risk measures that are comparable to KU. Dr. Avera does not consider any of the capital structures of the companies in the Utility Proxy Group "far out of line" with KU's target capital structure. Each company selects its target capital structure to balance the costs and benefits of debt with its other risk factors and financial objectives. The historical and projected capital structures for the firms in Dr. Avera's Utility Proxy Group were presented on Schedule WEA-8 to his testimony.

(2) The data requested is not publicly available to investors in one consistent location. Due to differences in reporting among utilities, it is difficult to get comparable data that would allow development of the requested revenue breakdown. In order to respond to this request, public financial records were reviewed for the companies including Value Line reports, corporate websites, annual reports, and filings with the Securities and Exchange Commission. The attached schedule reflects the results of that search. The empty cells reflect instances where comparable date for the utility was unavailable. The entries in italics are data that was derived from sources other than Value Line. Revenues subject to price regulation at the Federal Energy Regulatory Commission (FERC) were included in the category of Utility Not Subject to State Price Regulation.

	Company	Total Revenue	Non-Utility Sources	State Price Regulation	Utility Not State Price Regulation	Notes
1	ALLETE	$842	*44.0%*	*66.0%*	*10.0%*	*58% MPUC, 10% FERC, 8% PSCW*
2	Alliant Energy	$3,438	*36.1%*	*78.6%*	*14.7%*	*Non-utility estimated as all not identified*
3	Consolidated Edison	$13,120				*Total Utility of $10,821 indentified in NY, NJ, PA and FERC*
4	Constellation Energy	$21,193				*Regulated 12% electric and 4% gas*
5	Dominion Resources	$15,674				*Regulated electric $6,044 mil. and regulated gas $1,174 mil.*
6	Duke Energy	$12,720				*Regulated electric $8,976 mil. and regulated gas $720 mil.*
7	Entergy Corp.	$11,484				*Regulated utility revenues $9,225 mil.*
8	Exelon Corp.	$18,916		*61.7%*		*Unable to separate unregulated from not state price reg.*
9	Integrys Energy Group	$10,292	*67.9%*			*Unable to separate state price regulated from FERC*
10	MDU Resources Group	$4,248	*72.4%*			*Unable to separate state price regulated from FERC*
11	PG&E Corp.	$13,237	*0.0%*			*Unable to separate state price regulated from FERC*
12	P S Enterprise Group	$12,853	*33.9%*			*Unable to separate state price regulated from other regulation*
13	SCANA Corp.	$4,621	*33.8%*			*Unable to separate state price regulated from FERC*
14	Sempra Energy	$11,438	*38.3%*			*Unable to separate state price regulated from FERC*
15	Vectren Corp.	$2,282	*23.6%*			*Unable to separate state price regulated from other regulation*
16	Wisconsin Energy	$4,238	*0.5%*	*94.4%*	*5.1%*	
17	Xcel Energy, Inc.	$10,034	*2.4%*	*85.8%*	*11.8%*	*Non-utility may include some FERC transmission*
	KU	*$1,273*	*0.0%*	*88.4%*	*11.6%*	

Revenue in $ millions

(a) The Value Line Investment Survey (June 27, Aug. 8 & Aug. 29, 2008).

(b) Information from Company Form 10-K and Annual Reports presented in italics.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 14

Responding Witness: William Steven Seelye

Q-14. Refer to KU's response to Item 62 of Staff's Second Request, pages 26 to 30 of the Direct Testimony of William Steven Seelye, and Seelye Exhibits 9, 12, and 13.

a. Describe in detail the reasons for developing the proposed electric temperature normalization adjustment based on degree day variations for individual months as opposed to degree day variations for a complete season, i.e., the cooling season or the heating season.

b. Provide a revised run of Seelye Exhibits 12 and 13 based on total degree day variations for the heating season and cooling season based on the same bandwidth of two standard deviations centered on the mean used in the proposed electric temperature normalization adjustment.

A-14. a. The Company's proposed electric temperature normalization adjustment was based on degree day variations for individual months because of quantitative differences in temperature sensitivity from one month to another, especially during shoulder months. The impact of temperature on kWh sales during shoulder months differs significantly from the impact during non-shoulder months. The sales response to changes in temperature will be different when daily mean temperatures are between 55° F and 75° F (which often occurs during shoulder months) compared to when daily mean temperatures are outside of this range (which often occurs during non-shoulder months).

b. Attached is the requested analysis. This model would result in a revenue adjustment of -\$8,112,808 and an expense adjustment of -\$4,141,407, as compared to a revenue adjustment of -\$8,721,229 and expense adjustment of -\$4,355,146 proposed by the Company. The difference in the net adjustment resulting from the two methodologies is \$394,682.

The heating season was defined as the months of October through April, and the cooling season was defined as the months of May through September. In both the heating season model and cooling season model, the dependent variables were daily kWh sales for each rate class. The following independent variables were used in both models: (a) HDD65, (b) CDD65, (c) WEEKEND, and (d) HOLIDAY. The dichotomous indicator variable XMAS_WEEK was also used in the heating season model.

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect Weather Normalized Electric Sales Margins
12 Months Ended April 30, 2008

HEATING AND COOLING SEASONAL ADJUSTMENTS
HDD65 AND CDD65

	(1) kiloWatt-Hour Adjustment to Usage	(2) Energy Rate		(3) Revenue Adjustment		(4) Revenue Adjustment
				(2) * (1)		(3)
Residential Rate R	(68,641,000)	0.05774	$	(3,963,331)	$	(3,963,331)
Residential Rate FERS	(37,628,000)	0.05774	$	(2,172,641)	$	(2,172,641)
General Service Rate GS	(14,447,000)	0.06745	$	(974,450)	$	(974,450)
Large Power Rate LP	(30,320,000)		$	(1,002,386)	$	(1,002,386)
Secondary	(22,853,000)	0.03282	$	(750,035)		
Primary	(6,247,000)	0.03282	$	(205,027)		
Transmission	-	0.03282	$	-		
Secondary Small Time of Day	(1,220,000)	0.03879	$	(47,324)		
Primary Small Time of Day	-	0.03879	$	-		
Large Power Rate LCTOD	-		$	-	$	-
Primary	-	0.03282	$	-		
Transmission	-	0.03282	$	-		
Large Mine Power TOD	-		$	-	$	-
Primary	-	0.03082	$	-		
Transmission	-	0.03082	$	-		
Street Lighting	-		$	-	$	-
Total	(151,036,000)		$	(8,112,808)	$	(8,112,808)
Expenses (variable only)	(151,036,000)	0.02742	$	(4,141,407)	$	(4,141,407)
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES					$	(3,971,401)

Kentucky Utilities Company

Seasonal Electric Temperature Normalization Based on Subset of Weather Variables (HDD65 & CDD65)

Index	Year	Month	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjustment	Class Descr
1	2007	4	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	5	KU	0	0	-7209.44	0	0	0	0	0	-7209.436	RS
1	2007	6	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	7	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	8	KU	0	0	-34908.8	0	0	0	0	0	-34908.848	RS
1	2007	9	KU	0	-1074.43	-14039.4	0	0	0	0	0	-15113.86	RS
1	2007	10	KU	0	4318.396	-15727.1	0	0	0	0	0	-11408.718	RS
1	2007	11	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	12	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	2	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	3	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	4	KU	0	0	0	0	0	0	0	0	0	RS
2	2007	4	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	5	KU	0	0	-4340.91	0	0	0	0	0	-4340.911	RS (formerly Full Electric)
2	2007	6	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	7	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	8	KU	0	0	-21019.1	0	0	0	0	0	-21019.148	RS (formerly Full Electric)
2	2007	9	KU	0	-207.792	-8453.35	0	0	0	0	0	-8661.145	RS (formerly Full Electric)
2	2007	10	KU	0	12329.18	-15935.9	0	0	0	0	0	-3606.758	RS (formerly Full Electric)
2	2007	11	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	12	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	1	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	2	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	3	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	4	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
3	2007	4	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	5	KU	0	0	-1273.27	0	0	0	0	0	-1273.266	C/I GS Sec
3	2007	6	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	7	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	8	KU	0	0	-6165.29	0	0	0	0	0	-6165.288	C/I GS Sec
3	2007	9	KU	0	-396.9	-2479.52	0	0	0	0	0	-2876.418	C/I GS Sec
3	2007	10	KU	0	925.49	-5058	0	0	0	0	0	-4132.512	C/I GS Sec
3	2007	11	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	12	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	1	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	2	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	3	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	4	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec

Kentucky Utilities Company
Seasonal Electric Temperature Normalization Based on Subset of Weather Variables (HDD65 & CDD65)

Index	Year	Month	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjustment	Class Descr
7	2007	4	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	5	KU	0	0	-107.369	0	0	0	0	0	-107.369	C/I LP STOD Sec
7	2007	6	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	7	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	8	KU	0	0	-519.892	0	0	0	0	0	-519.892	C/I LP STOD Sec
7	2007	9	KU	0	-38.436	-209.087	0	0	0	0	0	-247.523	C/I LP STOD Sec
7	2007	10	KU	0	-39.634	-305.545	0	0	0	0	0	-345.179	C/I LP STOD Sec
7	2007	11	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	12	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	1	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	2	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	3	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	4	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
9	2007	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	5	KU	0	0	-1568.94	0	0	0	0	0	-1568.944	C/I LP Sec
9	2007	6	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	7	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	8	KU	0	0	-7596.99	0	0	0	0	0	-7596.992	C/I LP Sec
9	2007	9	KU	0	-479.892	-3055.31	0	0	0	0	0	-3535.204	C/I LP Sec
9	2007	10	KU	0	192.432	-4023.71	0	0	0	0	0	-3831.275	C/I LP Sec
9	2007	11	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	12	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	1	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	2	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	3	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
10	2007	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	5	KU	0	0	-509.675	0	0	0	0	0	-509.675	C/I LP Sec PF
10	2007	6	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	7	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	8	KU	0	0	-2467.9	0	0	0	0	0	-2467.9	C/I LP Sec PF
10	2007	9	KU	0	-129.684	-992.525	0	0	0	0	0	-1122.209	C/I LP Sec PF
10	2007	10	KU	0	31.882	-2253.08	0	0	0	0	0	-2221.201	C/I LP Sec PF
10	2007	11	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	12	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	1	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	2	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	3	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF

Kentucky Utilities Company
Seasonal Electric Temperature Normalization Based on Subset of Weather Variables (HDD65 & CDD65)

Index	Year	Month	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjustment	Class Descr
11	2007	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	5	KU	0	0	-85.728	0	0	0	0	0	-85.728	C/I LP Pri
11	2007	6	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	7	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	8	KU	0	0	-415.104	0	0	0	0	0	-415.104	C/I LP Pri
11	2007	9	KU	0	14.856	-166.944	0	0	0	0	0	-152.088	C/I LP Pri
11	2007	10	KU	0	14.326	-147.128	0	0	0	0	0	-132.802	C/I LP Pri
11	2007	11	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	12	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	1	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	2	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	3	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
12	2007	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	5	KU	0	0	-395.713	0	0	0	0	0	-395.713	C/I LP Pri PF
12	2007	6	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	7	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	8	KU	0	0	-1916.08	0	0	0	0	0	-1916.084	C/I LP Pri PF
12	2007	9	KU	0	-64.464	-770.599	0	0	0	0	0	-835.063	C/I LP Pri PF
12	2007	10	KU	0	15.656	-2330.2	0	0	0	0	0	-2314.542	C/I LP Pri PF
12	2007	11	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	12	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	1	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	2	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	3	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	4	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF

Kentucky Utilities
Normals and Standard Deviations

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev	20-Year Normal	20-Year Stdev
2008_1_1	1	1/1/2008	HDD60	1	857	854	171	857	790	152
2008_2_1	1	2/1/2008	HDD60	2	705	683	145	705	648	115
2008_3_1	1	3/1/2008	HDD60	3	485	477	93	485	473	93
2007_4_1	1	4/1/2007	HDD60	4	274	205	63	268	203	63
2007_5_1	1	5/1/2007	HDD60	5	17	50	36	17	48	36
2007_6_1	1	6/1/2007	HDD60	6	0	0	0	0	0	0
2007_7_1	1	7/1/2007	HDD60	7	0	0	0	0	0	0
2007_8_1	1	8/1/2007	HDD60	8	0	0	0	0	0	0
2007_9_1	1	9/1/2007	HDD60	9	1	18	15	3	18	15
2007_10_1	1	10/1/2007	HDD60	10	91	166	60	106	169	57
2007_11_1	1	11/1/2007	HDD60	11	432	421	97	432	427	104
2007_12_1	1	12/1/2007	HDD60	12	610	734	155	610	737	155
2008_4_1	1	4/1/2008	HDD60	4	200	205	63	200	203	63
2008_1_2	2	1/1/2008	HDD65	1	1007	1008	171	1007	945	152
2008_2_2	2	2/1/2008	HDD65	2	849	823	145	849	788	116
2008_3_2	2	3/1/2008	HDD65	3	639	621	101	639	616	102
2007_4_2	2	4/1/2007	HDD65	4	377	318	76	377	314	73
2007_5_2	2	5/1/2007	HDD65	5	59	113	59	59	112	60
2007_6_2	2	6/1/2007	HDD65	6	0	0	0	0	0	0
2007_7_2	2	7/1/2007	HDD65	7	0	0	0	0	0	0
2007_8_2	2	8/1/2007	HDD65	8	0	0	0	0	0	0
2007_9_2	2	9/1/2007	HDD65	9	13	51	26	25	52	26
2007_10_2	2	10/1/2007	HDD65	10	164	278	76	202	280	66
2007_11_2	2	11/1/2007	HDD65	11	577	563	102	577	570	107
2007_12_2	2	12/1/2007	HDD65	12	765	887	158	765	891	155
2008_4_2	2	4/1/2008	HDD65	4	319	318	76	319	314	73
2008_1_3	3	1/1/2008	CDD65	1	0	0	0	0	0	0
2008_2_3	3	2/1/2008	CDD65	2	0	0	0	0	0	0
2008_3_3	3	3/1/2008	CDD65	3	0	0	0	0	0	0
2007_4_3	3	4/1/2007	CDD65	4	21	18	16	21	19	18
2007_5_3	3	5/1/2007	CDD65	5	155	85	51	136	85	49
2007_6_3	3	6/1/2007	CDD65	6	284	235	54	284	235	51
2007_7_3	3	7/1/2007	CDD65	7	309	354	64	309	352	64
2007_8_3	3	8/1/2007	CDD65	8	496	324	80	404	328	81
2007_9_3	3	9/1/2007	CDD65	9	238	146	55	201	141	61
2007_10_3	3	10/1/2007	CDD65	10	100	25	22	47	25	23
2007_11_3	3	11/1/2007	CDD65	11	0	0	0	0	0	0
2007_12_3	3	12/1/2007	CDD65	12	0	0	0	0	0	0
2008_4_3	3	4/1/2008	CDD65	4	14	18	16	14	19	18

Kentucky Utilities
Normals and Standard Deviations

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev	20-Year Normal	20-Year Stdev
2008_1_4	4	1/1/2008	CDD70	1	0	0	0	0	0	0
2008_2_4	4	2/1/2008	CDD70	2	0	0	0	0	0	0
2008_3_4	4	3/1/2008	CDD70	3	0	0	0	0	0	0
2007_4_4	4	4/1/2007	CDD70	4	2	2	5	2	3	6
2007_5_4	4	5/1/2007	CDD70	5	64	27	25	52	27	23
2007_6_4	4	6/1/2007	CDD70	6	148	116	42	148	116	40
2007_7_4	4	7/1/2007	CDD70	7	157	204	61	157	202	61
2007_8_4	4	8/1/2007	CDD70	8	341	180	72	252	184	71
2007_9_4	4	9/1/2007	CDD70	9	124	63	37	100	59	39
2007_10_4	4	10/1/2007	CDD70	10	44	5	9	14	6	10
2007_11_4	4	11/1/2007	CDD70	11	0	0	0	0	0	0
2007_12_4	4	12/1/2007	CDD70	12	0	0	0	0	0	0
2008_4_4	4	4/1/2008	CDD70	4	3	2	5	3	3	6
2008_1_5	5	1/1/2008	MinTemp	1	745	760	167	745	818.4	151.9
2008_2_5	5	2/1/2008	MinTemp	2	805	763	141	805	796.65	113
2008_3_5	5	3/1/2008	MinTemp	3	1058	1091	93	1058	1094.3	96.1
2007_4_5	5	4/1/2007	MinTemp	4	1290	1335	84	1290	1338	90
2007_5_5	5	5/1/2007	MinTemp	5	1736	1674	102	1736	1674	102.3
2007_6_5	5	6/1/2007	MinTemp	6	1920	1872	54	1920	1872	48
2007_7_5	5	7/1/2007	MinTemp	7	1984	2065	56	2009	2064.6	52.7
2007_8_5	5	8/1/2007	MinTemp	8	2139	2027	74	2102	2027.4	74.4
2007_9_5	5	9/1/2007	MinTemp	9	1800	1731	69	1800	1725	66
2007_10_5	5	10/1/2007	MinTemp	10	1612	1438	105	1544	1435.3	83.7
2007_11_5	5	11/1/2007	MinTemp	11	1080	1119	99	1080	1107	93
2007_12_5	5	12/1/2007	MinTemp	12	992	877	155	992	877.3	145.7
2008_4_5	5	4/1/2008	MinTemp	4	1330	1335	84	1330	1338	90
2008_1_6	6	1/1/2008	MaxTemp	1	1256	1252	180	1256	1323.7	158.1
2008_2_6	6	2/1/2008	MaxTemp	2	1254	1260	155	1254	1299.5	124.3
2008_3_6	6	3/1/2008	MaxTemp	3	1676	1702	118	1676	1708.1	117.8
2007_4_6	6	4/1/2007	MaxTemp	4	1890	1962	93	1890	1971	84
2007_5_6	6	5/1/2007	MaxTemp	5	2480	2300	112	2412	2300.2	105.4
2007_6_6	6	6/1/2007	MaxTemp	6	2550	2478	78	2550	2475	84
2007_7_6	6	7/1/2007	MaxTemp	7	2635	2672	81	2635	2672.2	80.6
2007_8_6	6	8/1/2007	MaxTemp	8	2852	2647	99	2747	2656.7	99.2
2007_9_6	6	9/1/2007	MaxTemp	9	2520	2358	96	2454	2352	105
2007_10_6	6	10/1/2007	MaxTemp	10	2263	2086	81	2167	2086.3	83.7
2007_11_6	6	11/1/2007	MaxTemp	11	1650	1659	117	1650	1653	129
2007_12_6	6	12/1/2007	MaxTemp	12	1488	1376	164	1488	1370.2	164.3
2008_4_6	6	4/1/2008	MaxTemp	4	1943	1962	93	1943	1971	84

Kentucky Utilities
Normals and Standard Deviations

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev	20-Year Normal	20-Year Stdev
2008_1_7	7	1/1/2008	Open	1	0	0	0	0	0	0
2008_2_7	7	2/1/2008	Open	2	0	0	0	0	0	0
2008_3_7	7	3/1/2008	Open	3	0	0	0	0	0	0
2007_4_7	7	4/1/2007	Open	4	0	0	0	0	0	0
2007_5_7	7	5/1/2007	Open	5	0	0	0	0	0	0
2007_6_7	7	6/1/2007	Open	6	0	0	0	0	0	0
2007_7_7	7	7/1/2007	Open	7	0	0	0	0	0	0
2007_8_7	7	8/1/2007	Open	8	0	0	0	0	0	0
2007_9_7	7	9/1/2007	Open	9	0	0	0	0	0	0
2007_10_7	7	10/1/2007	Open	10	0	0	0	0	0	0
2007_11_7	7	11/1/2007	Open	11	0	0	0	0	0	0
2007_12_7	7	12/1/2007	Open	12	0	0	0	0	0	0
2008_4_7	7	4/1/2008	Open	4	0	0	0	0	0	0
2008_1_8	8	1/1/2008	Open	1	0	0	0	0	0	0
2008_2_8	8	2/1/2008	Open	2	0	0	0	0	0	0
2008_3_8	8	3/1/2008	Open	3	0	0	0	0	0	0
2007_4_8	8	4/1/2007	Open	4	0	0	0	0	0	0
2007_5_8	8	5/1/2007	Open	5	0	0	0	0	0	0
2007_6_8	8	6/1/2007	Open	6	0	0	0	0	0	0
2007_7_8	8	7/1/2007	Open	7	0	0	0	0	0	0
2007_8_8	8	8/1/2007	Open	8	0	0	0	0	0	0
2007_9_8	8	9/1/2007	Open	9	0	0	0	0	0	0
2007_10_8	8	10/1/2007	Open	10	0	0	0	0	0	0
2007_11_8	8	11/1/2007	Open	11	0	0	0	0	0	0
2007_12_8	8	12/1/2007	Open	12	0	0	0	0	0	0
2008_4_8	8	4/1/2008	Open	4	0	0	0	0	0	0

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 15

Responding Witness: William Steven Seelye

Q-15. Refer to KU's response to Staff's Second Request, Item 62(f). Explain why the revised run for HDD-60 and CDD-65 resulted in a larger kWh adjustment than the original run (Volume 5 of 5 of KU's application at Selyee's Testimony, Exhibits 12 and 13), which had more variables.

A-15. Reducing the number of variables in regression models will generally change the value of the coefficients of the remaining variables. The predictive quality of the original models (as indicated by the R-square of the model) is greater than or equal to the predictive quality of the revised models. For each of the months and classes where larger kWh differences occurred, the predictive quality of the original model was notably higher than the predictive quality of the revised model. Limiting the number of weather variables will not always result in a higher kWh adjustment. However, in these instances, the change in model specification caused a greater amount of the variability in daily energy to be associated with changes in weather.

Compared to the original kWh adjustment, the revised run for HDD-60 and CDD-65 resulted in a kWh adjustment that was 1.3% or 2,110,000 kWh higher. The difference is explained primarily by the residential classes (classes 1 and 20); in particular, positive differences in the May models are offset by smaller negative differences in other months.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 16

Responding Witness: Lonnie E. Bellar

Q-16. Refer to KU's response to Staff's Second Request, Item 13(f). In this response KU discusses the accounting treatment for contributions to different research and development ("R&D") projects. It states that some contributions are expensed "below-the-line" when incurred while others are deferred so that rate recovery can be sought. Explain how it is determined which R&D contributions are absorbed by stockholders through "below-the-line" charges and which R&D contributions are deferred for future rate recovery.

A-16. The Company assumes the reference is to KU's response to Staff's Second Request, Item 47(f).

The basic criterion for determining whether the cost of these types of research projects should be borne by the ratepayer is the probability of direct and timely benefits to customers. As an example, in the case of the contribution to the University of Kentucky of $1.5 million the research being supported was in its very early stages and although believed to ultimately be beneficial to ratepayers those benefits were not sufficiently defined at the time of the contribution. Also not as defined in the early 2006 time period when this contribution was being envisioned were the details and prospects of federal CO2 legislation. Thus, this initial $1.5m contribution to the University of Kentucky was recorded in such a way as to not be charged to ratepayers.

With the passage of time the details and prospect of federal CO2 legislation have become more defined and reasonably certain as have the proposals for research in the areas of Carbon Sequestration and Carbon Storage. With this, the decision was made in 2007 to provide funding to the Carbon Management Research Group and the Kentucky Consortium of Carbon Storage and that the benefits of these efforts would result in direct and timely benefits to customers. These contributions are the subject of and further discussed in Commission's Case No. 2008-00308, *In the Matter of: Joint Application Of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company And Louisville Gas And Electric Company For An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities Related To Certain Payments Made To Carbon Management Research Group And The Kentucky Consortium For Carbon Storage.*

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 17

Responding Witness: Chris Hermann / Shannon L. Charnas

Q-17. Refer to KU's response to Staff's Second Request, Item 69. In this response KU states that $541,061.40 is included in test year operating expenses for the Customer Care System ("CCS").

a. Explain why these costs were expensed rather than capitalized.

b. Provide all test year operating expenses that will not be incurred once the CCS is fully operational.

c. Provide a detailed estimate of the total operating expenses for the first 12 months of operation for the CCS.

A-17. a. These costs were expensed consistent with the Statement of Position 98-1 issued by the American Institute of Certified Public Accountants (AICPA) regarding accounting for software. These costs include items such as preparation and delivery of end-user communications and trainings, facilities costs, and hardware and software maintenance.

b. and c.

The operating expenses included in the test year associated with systems which will be replaced by CCS total $1,960,000. Additionally, $541,061 was incurred in the test year related to CCS project expenses. The total of the test year expenses that will not be incurred once CCS is fully operational is $2,501,061.

An estimate of the on-going annual operating and maintenance expenses of the CCS is $2,826,000. However, in the first 12 months, the Company will incur additional operating expenses of approximately $524,000 for post go-live technical support and licensing.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 18

Responding Witness: William Steven Seelye

Q-18. Refer to Volume 3 of 5 of KU's Application at Tab 42 where test year jurisdictional "Sales to Ultimate Consumers" is stated at $1,100,598,589. Reconcile this amount to the "Revenue As Billed" in the amount of $1,112,462,089 as shown at Volume 5 of 5 of KU's Application at Seelye's Exhibit 3, page 1 of 24.

A-18. These amounts are reconciled as follows:

Sales to Ultimate Consumers (KU Application Volume 3 of 5 at Tab 42)	$ 1,100,598,589
Revenue as Billed (Seelye Exhibit 3, page 1 of 24)	$ 1,112,462,089
Accrued Revenues	(17,682,129)
Unbilled Revenues	6,878,000
Merger Surcredit Amortization	(1,069,892)
Redundant Capacity	10,854
Revenue Adjustment	(334)
Sales to Ultimate Consumers	$ 1,100,598,589

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 19

Responding Witness: Shannon L. Charnas / Butch Cockerill / William Steven Seelye

Q-19. Refer to KU's response to Staff's Second Request, Item 68(d) and (e) and Volume 5 of 5 of KU's application at Seelye's Testimony, Exhibit 6, pages 8 and 9, schedules (a), (b), and (c).

a. State the amount of late payment penalties included on schedule (b) for each year shown in columns 1 and 2.

b. State the amount of late payment penalties included on schedule (c) for each year shown in columns 1 and 2.

c. When LG&E issues a customer bill, the amount of the late payment penalty is shown on the bill.

(1) Is the late payment penalty shown on the bill included in customer accounts receivable recorded on LG&E's books upon the initial issuance of the bill?

(2) If no to (1), explain how and when a late payment penalty is included in customer accounts receivables.

(3) Provide the amounts of "Forfeited Discounts" for each year shown on schedule (a) of Exhibit 6, page 8, that were paid by the customer before the "Forfeited Discount" was included in customer accounts receivables Separate this response by customer class code.

d. At Item 68(d), KU states that the other measurements (referring to the percent of "charge-offs" to revenue and percent of Accounts Receivable to revenue as calculated on schedules (b) and (c) of Exhibit 6, page 9) indicate the customers in KU's service territory will likely be charged fewer late payment charges than customers in LG&E's service territory.

(1) Explain how this conclusion can be drawn from Exhibit 6, page 9,

schedules (b) and (c).

(2) Explain whether at least a portion, if not all, of the difference in the percentage of "charge-offs" and Accounts Receivable to revenues for LG&E and KU as shown on schedules (b) and (c) is attributable to the fact that LG&E "charge-offs" and Accounts Receivable shown in column 2 include late payment penalties while KU's "charge-offs" and Accounts Receivables as shown in column 5 do not include late payment penalties.

e. At Item 68(e), KU was requested to discuss the consideration given to the differences in LG&E's and KU's billing practices when weighing the late payment penalty revenue on Accounts Receivable balances. KU's response stated that consideration was given to "this factor," but did not give a full explanation. State the amount of the difference in LG&E's and KU's percentages of Accounts Receivable to billed revenues for the years shown in schedule (c) that is attributable to the differences in LG&E's and KU's billing and collection practices.

A-19. a. LG&E late payment penalties are not included in column 1 on schedule (b). Due to Customer Information System limitations, details in net charge offs are not available. Therefore, the late payment penalties in column 2 on schedule (b) cannot be determined.

b. Late payment penalties for LG&E included on schedule (c):

	Column (1) ($000)	Column (2) ($000)
2007	-	251
2006	-	246
2005	-	227
2004	-	494
2003	-	476

c. (1) The late payment penalty shown on LG&E's bill is not included in customer accounts receivable recorded on LG&E's books upon the initial issuance of the bill. The penalty is not considered a receivable until the customer is late remitting payment.

(2) The penalty is not included LG&E customer accounts receivable until the customer is billed for the late payment penalty in a subsequent billing month.

(3) LG&E does not calculate or track "forfeited discounts" (late payment charges incurred by the customers) before they are included in customer accounts receivable.

d. (1) KU's net charge-offs as a percent of ultimate customer revenues are less than one-half of the comparable figure for LG&E. Since net charge-offs represent the amount of KU's accounts receivable balance that is written off (and therefore removed from accounts receivable), net charge-offs are indicative of total payment habits of KU's customers.

(2) Although a portion of LG&E's charge offs would include amounts related to late payment charges, it is the Company's experience that customers in KU's service territory have paid their bills in a more timely and complete manner than customers in LG&E's service territory.

e. KU has not measured the amount of the difference in LG&E's and KU's percentages of accounts receivable to billed revenue that is attributable to the differences in the Companies' billing and collection practices. Determining such a difference with any degree of confidence would require performing a controlled experiment (such as an Analysis of Variance – ANOVA test) to evaluate the different billing and collection practices using customer panels selected from subsets that have similar demographic and geographic characteristics. This kind of analysis would require a substantial amount of work and has not been performed.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 20

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

Q-20. In Case No, 2007-00565, KU requests approval of a depreciation study based on the equal life group ("ELG") method for all plant placed into service as of December 31, 2006. The results of the study were summarized in KU's application at Exhibit JJS-KU, III-4 through III-10. As shown on page III-10, the equal life group method resulted in an annual depreciation expense for KU of $111,765,099.

a. Refer to KU's response to Staff's Second Request, Item 84(c). It is stated that, during the formulation of the depreciation study, the average life group method was applied to calculate depreciable lives at the same time that the equal life group was used. Provide the results of the depreciation study using the average life group method when applied to plant in service as of December 31, 2006. Provide this response in the same format as Exhibit JJS-KU, III-4 through III-10.

b. Provide the workpapers that clearly demonstrate the core/root differences in the equal life group method used to calculate the depreciation shown in KU's application at Exhibit JJS-KU, III-4 through III-10 and the depreciation calculated in (a) using the average life group.

c. Using the composite depreciation rates provided in (a), recalculate depreciation for plant in service as of April 30, 2008. The response to this request should be presented in the same format used in KU's response to Staffs Second Request, Item 90, pages 2 – 10.

A-20. a. See attached, as was provided in Case No. 2007-00565, Response to the Attorney General's Initial Requests for Information dated February 4, 2008, Question No. 27.

b. Other than the testimony referenced in KU's response to PSC-2 Question No. 84, there are no workpapers that demonstrate the core/root differences in the ELG method. The root differences between the average service life and equal life group procedures deal with the recovery rates of plant in service. The average service life procedure is based on direct weighting of all plant assets regardless of their age. The equal life group procedure more appropriately matches the level of recovery to the usefulness of the asset. Therefore, using the equal life group procedure is designed to recover each vintage based on its attained age.

c. See attached.

Attachment to Response to PSC-3 Question No. 20(a)
Responding Witness – Charnas / Spanos

ASL

KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	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)
	DEPRECIABLE PLANT								
	STEAM PRODUCTION PLANT								
311.00	STRUCTURES AND IMPROVEMENTS								
	TYRONE UNIT 3	100-S1.5 *	(5)	5,447,348.04	5,719,715	0	0	-	-
	TYRONE UNITS 1 & 2	100-S1.5 *	(5)	594,089.12	623,794	0	0	-	-
	GREEN RIVER UNIT 3	100-S1.5 *	(5)	2,818,747.44	2,959,685	0	0	-	-
	GREEN RIVER UNIT 4	100-S1.5 *	(5)	4,475,383.64	4,699,153	0	0	-	-
	GREEN RIVER UNITS 1 & 2	100-S1.5 *	(5)	2,596,589.06	2,726,419	0	0	-	-
	E W BROWN STEAM UNIT 1	100-S1.5 *	(5)	4,294,488.60	4,007,844	501,368	25,845	0.60	19.4
	E W BROWN STEAM UNIT 2	100-S1.5 *	(5)	1,542,703.85	1,595,211	24,629	1,266	0.08	19.5
	E W BROWN STEAM UNIT 3	100-S1.5 *	(5)	12,466,774.95	11,779,068	1,311,046	67,803	0.54	19.3
	GHENT UNIT 1 SCRUBBER	100-S1.5 *	(5)	24,298,756.00	13,016,631	12,497,063	644,511	2.65	19.4
	GHENT UNIT 1	100-S1.5 *	(5)	17,160,534.10	16,736,391	1,282,170	66,702	0.39	19.2
	GHENT UNIT 2	100-S1.5 *	(5)	16,175,819.55	15,355,831	1,628,781	81,369	0.50	20.0
	GHENT UNIT 3	100-S1.5 *	(5)	43,264,065.36	30,770,444	14,656,826	512,840	1.19	28.6
	GHENT UNIT 4	100-S1.5 *	(5)	22,674,768.92	14,633,236	9,175,272	319,236	1.41	28.7
	SYSTEM LABORATORY	100-S1.5 *	(5)	805,717.00	488,697	357,306	12,400	1.54	28.8
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS			158,615,785.63	125,112,119	41,434,461	1,731,972	1.09	23.9
312.00	BOILER PLANT EQUIPMENT								
	TYRONE UNIT 3	65-R2 *	(20)	12,078,002.67	9,052,070	5,441,534	480,468	3.98	11.3
	TYRONE UNITS 1 & 2	65-R2 *	(20)	3,531,623.26	4,193,561	44,386	3,995	0.11	11.1
	GREEN RIVER UNIT 3	65-R2 *	(20)	11,195,261.77	9,565,842	3,868,472	342,647	3.06	11.3
	GREEN RIVER UNIT 4	65-R2 *	(20)	23,652,944.82	17,191,266	11,192,270	989,652	4.18	11.3
	GREEN RIVER UNITS 1 & 2	65-R2 *	(20)	399,431.39	382,655	96,664	8,633	2.16	11.2
	E W BROWN STEAM UNIT 1	65-R2 *	(20)	35,546,187.28	22,971,136	19,684,289	1,055,029	2.97	18.7
	E W BROWN STEAM UNIT 2	65-R2 *	(20)	29,161,949.77	18,640,534	16,353,806	876,626	3.01	18.7
	E W BROWN STEAM UNIT 3	65-R2 *	(20)	79,655,480.64	54,260,794	41,325,781	2,224,398	2.79	18.6
	PINEVILL UNIT 3	65-R2 *	(20)	279,751.37	335,702	0	0	-	-
	GHENT UNIT 1 SCRUBBER	65-R2 *	(20)	86,520,258.20	40,651,742	63,172,568	3,343,532	3.86	18.9
	GHENT UNIT 1	65-R2 *	(20)	162,626,761.08	77,653,906	117,498,208	6,234,675	3.83	18.8
	GHENT UNIT 2	65-R2 *	(20)	89,742,087.02	67,526,984	40,163,521	2,086,217	2.32	19.3
	GHENT UNIT 3	65-R2 *	(20)	244,747,430.08	118,161,545	175,535,370	6,428,604	2.63	27.3
	GHENT UNIT 4	65-R2 *	(20)	247,916,189.17	107,189,341	190,310,084	6,912,298	2.79	27.5
	GHENT LOCOMOTIVES - RAIL CARS	25-R2	20	7,647,232.00	3,735,435	2,382,351	191,047	2.50	12.5
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT			1,034,700,590.52	551,512,513	687,069,304	31,177,821	3.01	22.0

KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	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)
314.00	TURBOGENERATOR UNITS								
	TYRONE UNIT 3	55-R2.5	(15)	4,154,426.75	3,150,207	1,627,384	142,875	3.44	11.4
	TYRONE UNITS 1 & 2	55-R2.5	(15)	1,592,029.00	1,830,833	0	0		
	GREEN RIVER UNIT 3	55-R2.5	(15)	4,214,807.78	3,456,160	1,390,868	122,123	2.90	11.4
	GREEN RIVER UNIT 4	55-R2.5	(15)	10,005,416.72	7,204,057	4,302,172	379,045	3.79	11.4
	E W BROWN STEAM UNIT 1	55-R2.5	(15)	4,997,832.45	4,768,484	979,022	56,161	1.12	17.4
	E W BROWN STEAM UNIT 2	55-R2.5	(15)	10,874,093.96	6,624,591	5,880,617	316,738	2.91	18.6
	E W BROWN STEAM UNIT 3	55-R2.5	(15)	27,652,379.12	15,467,528	16,332,708	875,203	3.17	18.7
	PINEVILL UNIT 3	55-R2.5	(15)	6.00	7	0	0		
	GHENT UNIT 1	55-R2.5	(15)	25,577,292.00	19,103,945	10,309,940	569,356	2.23	18.1
	GHENT UNIT 2	55-R2.5	(15)	29,546,660.86	22,424,968	11,553,692	613,544	2.08	18.8
	GHENT UNIT 3	55-R2.5	(15)	39,424,927.73	24,916,555	20,422,112	798,801	2.03	25.6
	GHENT UNIT 4	55-R2.5	(15)	51,736,214.11	29,734,684	29,761,963	1,137,802	2.20	26.2
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS			209,776,086.48	138,682,019	102,560,478	5,011,648	2.39	20.5
315.00	ACCESSORY ELECTRIC EQUIPMENT								
	TYRONE UNIT 3	70-S3	(5)	570,737.00	599,274	0	0		
	TYRONE UNITS 1 & 2	70-S3	(5)	828,017.00	869,418	0	0		
	GREEN RIVER UNIT 3	70-S3	(5)	741,256.89	778,320	0	0		
	GREEN RIVER UNIT 4	70-S3	(5)	1,145,214.38	1,010,620	191,856	16,683	1.46	11.5
	E W BROWN STEAM UNIT 1	70-S3	(5)	3,329,621.65	2,136,619	1,359,485	69,775	2.10	19.5
	E W BROWN STEAM UNIT 2	70-S3	(5)	997,856.05	954,378	93,372	4,793	0.48	19.5
	E W BROWN STEAM UNIT 3	70-S3	(5)	5,145,132.14	4,865,606	536,781	27,693	0.54	19.4
	PINEVILL UNIT 3	70-S3	(5)	4,091.00	4,296	0	0		
	GHENT UNIT 1 SCRUBBER	70-S3	(5)	3,016,784.00	1,580,263	1,587,360	81,487	2.70	19.5
	GHENT UNIT 1	70-S3	(5)	7,641,004.90	7,214,612	808,444	42,128	0.55	19.2
	GHENT UNIT 2	70-S3	(5)	10,785,959.00	10,038,015	1,287,242	64,799	0.60	19.9
	GHENT UNIT 3	70-S3	(5)	25,961,222.00	19,793,702	7,465,581	268,633	1.03	27.8
	GHENT UNIT 4	70-S3	(5)	21,911,934.44	15,446,906	7,560,624	267,375	1.22	28.3
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT			82,078,830.45	65,292,029	20,890,745	843,366	1.03	24.8
316.00	MISCELLANEOUS PLANT EQUIPMENT								
	TYRONE UNIT 3	70-R1.5	0	508,751.25	329,761	178,990	15,874	3.12	11.3
	TYRONE UNITS 1 & 2	70-R1.5	0	59,096.15	59,096	0	0		
	GREEN RIVER UNIT 3	70-R1.5	0	153,389.71	84,649	68,741	6,085	3.97	11.3
	GREEN RIVER UNIT 4	70-R1.5	0	2,096,051.79	1,455,549	640,502	56,857	2.71	11.3
	GREEN RIVER UNITS 1 & 2	70-R1.5	0	84,747.63	84,748	0	0		
	E W BROWN STEAM UNIT 1	70-R1.5	0	424,040.93	243,531	180,510	9,584	2.26	18.8
	E W BROWN STEAM UNIT 2	70-R1.5	0	85,648.00	74,409	11,239	606	0.71	18.5
	E W BROWN STEAM UNIT 3	70-R1.5	0	4,233,635.79	2,389,102	1,844,533	98,615	2.33	18.7
	PINEVILL UNIT 3	70-R1.5	0	56,611.00	56,611	0	0		
	GHENT UNIT 1 SCRUBBER	70-R1.5	0	985,410.00	454,155	531,255	28,319	2.87	18.8
	GHENT UNIT 1	70-R1.5	0	1,756,976.98	1,308,821	448,156	24,202	1.38	18.5
	GHENT UNIT 2	70-R1.5	0	1,493,092.78	1,187,409	305,684	15,946	1.07	19.2
	GHENT UNIT 3	70-R1.5	0	3,118,291.77	1,956,104	1,162,188	43,528	1.40	26.7
	GHENT UNIT 4	70-R1.5	0	6,052,103.27	2,685,232	3,366,872	122,832	2.03	27.4
	SYSTEM LABORATORY	70-R1.5	0	2,198,264.39	525,026	1,673,239	60,165	2.74	27.8
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT			23,306,111.44	12,894,203	10,411,909	482,613	2.07	21.6
	TOTAL STEAM PRODUCTION PLANT			**1,508,477,404.52**	**893,492,883**	**862,366,897**	**39,247,420**		

KENTUCKY UTILITIES
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	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)
	HYDROELECTRIC PRODUCTION PLANT									
330.10	LAND AND LAND RIGHTS									
	DIX DAM	100-R4	*	0	879,311.47	905,781	(26,470)	0	-	-
	TOTAL ACCOUNT 330.1 - LAND RIGHTS				879,311.47	905,781	(26,470)	0	-	-
331.00	STRUCTURES AND IMPROVEMENTS									
	DIX DAM	90-S2.5	*	(5)	453,195.00	316,800	159,057	5,836	1.29	27.3
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS				453,195.00	316,800	159,057	5,836	1.29	27.3
332.00	RESERVOIRS, DAMS & WATERWAY									
	DIX DAM	100-S2.5	*	0	7,954,452.04	6,384,461	1,569,991	56,906	0.72	27.6
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS & WATERWAYS				7,954,452.04	6,384,461	1,569,991	56,906	0.72	27.6
333.00	WATER WHEELS, TURBINES & GENERATORS									
	DIX DAM	80-R3	*	(10)	420,536.56	394,072	68,518	2,770	0.66	24.7
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES & GENERATORS				420,536.56	394,072	68,518	2,770	0.66	24.7
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	DIX DAM	40-L2.5	*	0	85,383.14	76,888	8,495	707	0.83	12.0
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT				85,383.14	76,888	8,495	707	0.83	12.0
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	DIX DAM	35-L1	*	0	101,512.96	39,455	62,058	3,603	3.55	17.2
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT				101,512.96	39,455	62,058	3,603	3.55	17.2
336.00	ROADS, RAILROADS, & BRIDGES									
	DIX DAM	55-R4	*	0	46,976.13	48,390	(1,414)	0	-	-
	TOTAL ACCOUNT 336 - ROADS, RAILROADS & BRIDGES				46,976.13	48,390	(1,414)	0	-	-
	TOTAL HYDROELECTRIC PRODUCTION PLANT				**9,941,367.30**	**8,165,847**	**1,840,235**	**69,822**		
	OTHER PRODUCTION PLANT									
340.10	LAND RIGHTS									
	E W BROWN CT UNIT 9 GAS PIPE	30-R0.5	*	0	176,409.31	71,698	104,711	5,231	2.97	20.0
	TOTAL ACCOUNT 340.1 - LAND RIGHTS				176,409.31	71,698	104,711	5,231	2.97	20.0

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341.00	STRUCTURES AND IMPROVEMENTS								
	PADDY'S RUN GENERATOR 13	40-R2.5 *	0	1,910,328.00	374,109	1,536,219	57,947	3.03	26.5
	E W BROWN CT UNIT 5	40-R2.5 *	0	775,082.20	149,820	625,262	23,569	3.04	26.5
	E W BROWN CT UNIT 6	40-R2.5 *	0	192,813.69	36,791	156,023	5,890	3.05	26.5
	E W BROWN CT UNIT 7	40-R2.5 *	0	544,966.20	126,941	418,026	15,978	2.93	26.2
	E W BROWN CT UNIT 8	40-R2.5 *	0	2,012,654.53	717,642	1,295,013	52,375	2.60	24.7
	E W BROWN CT UNIT 9	40-R2.5 *	0	4,641,054.53	1,654,146	2,986,909	120,844	2.60	24.7
	E W BROWN CT UNIT 10	40-R2.5 *	0	1,865,718.54	662,603	1,203,116	48,615	2.61	24.7
	E W BROWN CT UNIT 11	40-R2.5 *	0	1,858,754.33	579,307	1,279,447	50,541	2.72	25.3
	TRIMBLE COUNTY CT UNIT 5	40-R2.5 *	0	3,740,231.26	592,365	3,147,866	117,507	3.14	26.8
	TRIMBLE COUNTY CT UNIT 6	40-R2.5 *	0	3,588,684.33	588,760	2,999,924	112,134	3.12	26.8
	TRIMBLE COUNTY CT UNIT 7	40-R2.5 *	0	3,559,154.97	343,098	3,216,057	118,324	3.32	27.2
	TRIMBLE COUNTY CT UNIT 8	40-R2.5 *	0	3,548,851.71	342,104	3,206,748	117,982	3.32	27.2
	TRIMBLE COUNTY CT UNIT 9	40-R2.5 *	0	3,655,976.41	352,432	3,303,544	121,543	3.32	27.2
	TRIMBLE COUNTY CT UNIT 10	40-R2.5 *	0	3,653,029.99	352,147	3,300,883	121,445	3.32	27.2
	HAEFLING UNITS 1, 2 & 3	40-R2.5 *	0	434,853.00	337,009	97,844	28,116	6.47	3.5
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS			35,982,153.69	7,209,274	28,772,881	1,112,810	3.09	25.9
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES								
	PADDY'S RUN GENERATOR 13	45-R2.5 *	(5)	1,995,102.07	402,765	1,692,092	62,056	3.11	27.3
	E W BROWN CT UNIT 5	45-R2.5 *	(5)	727,929.00	147,963	616,363	22,611	3.11	27.3
	E W BROWN CT UNIT 6	45-R2.5 *	(5)	146,515.00	38,566	115,275	4,285	2.92	26.9
	E W BROWN CT UNIT 7	45-R2.5 *	(5)	145,745.00	38,363	114,669	4,263	2.92	26.9
	E W BROWN CT UNIT 8	45-R2.5 *	(5)	19,613.00	7,132	13,461	516	2.63	26.1
	E W BROWN CT UNIT 9	45-R2.5 *	(5)	1,932,186.25	694,487	1,334,308	51,129	2.65	26.1
	E W BROWN CT UNIT 10	45-R2.5 *	(5)	31,737.00	11,607	21,717	834	2.63	26.0
	E W BROWN CT UNIT 11	45-R2.5 *	(5)	52,430.00	17,145	37,907	1,436	2.74	26.4
	E W BROWN CT UNIT 9 GAS PIPE	45-R2.5 *	(5)	8,106,131.85	3,135,265	5,376,173	208,199	2.57	25.8
	TRIMBLE COUNTY CT UNIT 5	45-R2.5 *	(5)	239,584.64	40,738	210,825	7,685	3.21	27.4
	TRIMBLE COUNTY CT UNIT 6	45-R2.5 *	(5)	239,245.94	40,695	210,513	7,674	3.21	27.4
	TRIMBLE COUNTY CT PIPELINE	45-R2.5 *	(5)	4,850,114.45	786,421	4,306,200	156,779	3.23	27.5
	TRIMBLE COUNTY CT UNIT 7	45-R2.5 *	(5)	578,059.38	57,997	548,965	19,797	3.42	27.7
	TRIMBLE COUNTY CT UNIT 8	45-R2.5 *	(5)	576,385.74	57,829	547,376	19,739	3.42	27.7
	TRIMBLE COUNTY CT UNIT 9	45-R2.5 *	(5)	593,786.01	59,574	563,901	20,335	3.42	27.7
	TRIMBLE COUNTY CT UNIT 10	45-R2.5 *	(5)	593,307.31	59,526	563,447	20,319	3.42	27.7
	HAEFLING UNITS 1, 2 & 3	45-R2.5 *	(5)	181,132.00	190,189	0	0	-	-
	TOTAL ACCOUNT 342 - FULE HOLDERS, PRODUCERS AND ACCESSORIES			21,009,004.64	5,786,262	16,273,192	607,657	2.89	26.8
343.00	PRIME MOVERS								
	PADDY'S RUN GENERATOR 13	35-R1 *	(5)	17,420,148.57	3,208,506	15,082,650	631,235	3.62	23.9
	E W BROWN CT UNIT 5	35-R1 *	(5)	13,164,181.28	2,305,155	11,517,235	480,759	3.65	24.0
	E W BROWN CT UNIT 6	35-R1 *	(5)	30,399,242.38	6,414,963	25,504,241	1,078,577	3.55	23.6
	E W BROWN CT UNIT 7	35-R1 *	(5)	30,001,197.85	6,051,587	25,449,672	1,072,644	3.58	23.7
	E W BROWN CT UNIT 8	35-R1 *	(5)	20,074,864.20	5,994,874	15,083,733	662,762	3.30	22.8
	E W BROWN CT UNIT 9	35-R1 *	(5)	21,502,645.45	6,950,677	15,627,102	695,270	3.23	22.5
	E W BROWN CT UNIT 10	35-R1 *	(5)	19,670,647.49	6,157,363	14,496,817	641,188	3.26	22.6
	E W BROWN CT UNIT 11	35-R1 *	(5)	34,239,853.35	8,782,372	27,169,474	1,169,194	3.41	23.2
	TRIMBLE COUNTY CT UNIT 5	35-R1 *	(5)	30,530,609.97	4,681,480	27,375,660	1,134,697	3.72	24.1
	TRIMBLE COUNTY CT UNIT 6	35-R1 *	(5)	30,442,270.01	4,682,426	27,281,957	1,131,153	3.72	24.1
	TRIMBLE COUNTY CT UNIT 7	35-R1 *	(5)	22,773,833.23	2,046,994	21,865,531	891,491	3.91	24.5
	TRIMBLE COUNTY CT UNIT 8	35-R1 *	(5)	22,568,286.07	2,036,130	21,660,571	883,200	3.91	24.5

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	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)
	TRIMBLE COUNTY CT UNIT 9	35-R1	(5)	22,401,685.39	2,020,924	21,500,846	876,686	3.91	24.5
	TRIMBLE COUNTY CT UNIT 10	35-R1	(5)	22,378,127.55	2,018,755	21,478,279	875,765	3.91	24.5
	TOTAL ACCOUNT 343 - PRIME MOVERS			337,567,592.79	63,352,206	291,093,768	12,224,821	3.62	23.8
344.00	GENERATORS								
	PADDY'S RUN GENERATOR 13	55-S3	(5)	5,185,636.00	1,003,503	4,441,415	152,468	2.94	29.1
	E W BROWN CT UNIT 5	55-S3	(5)	2,831,528.00	548,012	2,425,092	83,251	2.94	29.1
	E W BROWN CT UNIT 6	55-S3	(5)	3,712,349.00	930,433	2,967,533	102,435	2.76	29.0
	E W BROWN CT UNIT 7	55-S3	(5)	3,722,788.00	931,357	2,977,570	102,776	2.76	29.0
	E W BROWN CT UNIT 8	55-S3	(5)	4,953,961.00	1,736,820	3,464,839	121,659	2.46	28.5
	E W BROWN CT UNIT 9	55-S3	(5)	5,452,041.03	2,153,184	3,571,459	126,095	2.31	28.3
	E W BROWN CT UNIT 10	55-S3	(5)	4,944,693.00	1,733,570	3,458,358	121,431	2.46	28.5
	E W BROWN CT UNIT 11	55-S3	(5)	5,187,040.00	1,694,228	3,752,164	131,089	2.53	28.6
	TRIMBLE COUNTY CT UNIT 5	55-S3	(5)	3,763,274.68	610,505	3,340,933	114,413	3.04	29.2
	TRIMBLE COUNTY CT UNIT 6	55-S3	(5)	3,757,946.86	609,864	3,335,980	114,243	3.04	29.2
	TRIMBLE COUNTY CT UNIT 7	55-S3	(5)	2,950,282.37	282,683	2,815,113	96,079	3.26	29.3
	TRIMBLE COUNTY CT UNIT 8	55-S3	(5)	2,937,930.22	281,499	2,803,328	95,677	3.26	29.3
	TRIMBLE COUNTY CT UNIT 9	55-S3	(5)	2,957,520.12	283,376	2,822,020	96,315	3.26	29.3
	TRIMBLE COUNTY CT UNIT 10	55-S3	(5)	2,954,148.53	283,053	2,818,803	96,205	3.26	29.3
	HAEFLING UNITS 1, 2 & 3	55-S3	(5)	4,023,003.00	4,224,153	0	0	-	-
	TOTAL ACCOUNT 344 - GENERATORS			59,334,141.81	17,306,240	44,994,607	1,554,136	2.62	29.0
345.00	ACCESSORY ELECTRIC EQUIPMENT								
	PADDY'S RUN GENERATOR 13	45-R3	0	2,456,320.00	488,379	1,967,941	70,864	2.88	27.8
	E W BROWN CT UNIT 5	45-R3	0	1,332,167.00	264,860	1,067,307	38,434	2.89	27.8
	E W BROWN CT UNIT 6	45-R3	0	1,354,817.00	349,592	1,005,225	36,700	2.71	27.4
	E W BROWN CT UNIT 7	45-R3	0	1,347,700.00	347,755	999,945	36,508	2.71	27.4
	E W BROWN CT UNIT 8	45-R3	0	1,797,054.00	650,416	1,146,638	43,382	2.41	26.4
	E W BROWN CT UNIT 9	45-R3	0	3,226,185.73	1,256,027	1,970,159	74,763	2.32	26.4
	E W BROWN CT UNIT 10	45-R3	0	1,804,419.00	637,098	1,167,321	43,992	2.44	26.5
	E W BROWN CT UNIT 11	45-R3	0	916,326.00	308,077	608,249	22,764	2.48	26.7
	TRIMBLE COUNTY CT UNIT 5	45-R3	0	1,677,092.15	279,094	1,397,998	50,032	2.98	27.9
	TRIMBLE COUNTY CT UNIT 6	45-R3	0	1,674,719.12	278,801	1,395,918	49,958	2.98	27.9
	TRIMBLE COUNTY CT UNIT 7	45-R3	0	3,146,235.12	308,469	2,837,766	100,487	3.19	28.2
	TRIMBLE COUNTY CT UNIT 8	45-R3	0	3,137,127.45	307,577	2,829,550	100,197	3.19	28.2
	TRIMBLE COUNTY CT UNIT 9	45-R3	0	3,231,827.28	316,862	2,914,965	103,221	3.19	28.2
	TRIMBLE COUNTY CT UNIT 10	45-R3	0	3,229,222.72	316,607	2,912,616	103,138	3.19	28.2
	HAEFLING UNITS 1, 2 & 3	45-R3	0	621,207.00	621,207	0	0	-	-
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT			30,952,419.57	6,730,821	24,221,598	874,440	2.83	27.7

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	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)
346.00	MISCELLANEOUS PLANT EQUIPMENT								
	PADDY'S RUN GENERATOR 13	35-R2 *	0	1,089,549.00	224,313	865,236	34,901	3.20	24.8
	E W BROWN CT UNIT 5	35-R2 *	0	2,108,910.25	435,769	1,673,141	67,461	3.20	24.8
	E W BROWN CT UNIT 6	35-R2 *	0	48,958.88	7,842	41,117	1,632	3.33	25.2
	E W BROWN CT UNIT 7	35-R2 *	0	35,647.85	6,968	28,680	1,153	3.23	24.9
	E W BROWN CT UNIT 8	35-R2 *	0	230,069.23	86,699	143,370	6,378	2.77	22.5
	E W BROWN CT UNIT 9	35-R2 *	0	760,256.23	287,309	472,947	21,049	2.77	22.5
	E W BROWN CT UNIT 10	35-R2 *	0	274,390.79	94,590	179,801	7,833	2.85	23.0
	E W BROWN CT UNIT 11	35-R2 *	0	548,588.10	111,544	437,044	17,664	3.22	24.7
	TRIMBLE COUNTY CT UNIT 5	35-R2 *	0	15,274.16	324	14,950	569	3.73	26.3
	TRIMBLE COUNTY CT UNIT 7	35-R2 *	0	8,888.93	899	7,990	311	3.50	25.7
	TRIMBLE COUNTY CT UNIT 8	35-R2 *	0	8,861.01	895	7,966	310	3.50	25.7
	TRIMBLE COUNTY CT UNIT 9	35-R2 *	0	9,113.52	921	8,193	319	3.50	25.7
	TRIMBLE COUNTY CT UNIT 10	35-R2 *	0	9,105.52	921	8,185	318	3.49	25.7
	HAEFLING UNITS 1, 2 & 3	35-R2 *	0	35,805.00	35,805	0	0		
	TOTAL ACCOUNT 346 - MISCELLANEOUS PLANT EQUIPMENT			5,183,418.47	1,294,799	3,888,620	159,898	3.08	24.3
	TOTAL OTHER PRODUCTION PLANT			490,205,140.28	101,751,300	409,349,377	16,538,993		
	TRANSMISSION PLANT								
350.10	LAND AND LAND RIGHTS	60-R3	0	23,341,455.00	15,050,587	8,290,867	229,612	0.98	36.1
352.10	STRUCTURES & IMPROVEMENTS-NON SYS CONTROL/COM	65-S2.5	(25)	6,979,653.25	3,813,782	4,910,791	107,419	1.54	45.7
352.20	STRUCTURES & IMPROVEMENTS - SYS CONTROL/COM	60-R3	(25)	1,167,783.17	813,907	645,823	16,739	1.43	38.6
353.10	STATION EQUIPMENT - NON SYS CONTROL/COM	60-R2	(20)	173,142,340.90	59,471,929	148,298,883	3,431,123	1.98	43.2
353.20	STATION EQUIPMENT - SYS CONTROL/COM	30-R2.5	(20)	14,749,280.69	16,016,356	1,682,783	68,381	0.46	24.6
354.00	TOWERS AND FIXTURES	70-R4	(25)	63,308,079.23	42,955,413	36,179,691	763,846	1.21	47.4
355.00	POLES AND FIXTURES	50-R2	(60)	91,302,830.77	64,368,897	81,715,632	2,079,841	2.28	39.3
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R3	(50)	129,755,652.44	100,060,047	94,573,434	2,325,390	1.79	40.7
357.00	UNDERGROUND CONDUIT	40-L2.5	0	448,760.26	134,595	314,165	11,690	2.60	26.9
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-R3	0	1,114,761.90	802,730	312,032	14,059	1.26	22.2
	TOTAL TRANSMISSION PLANT			505,310,597.61	303,488,243	376,924,101	9,048,100		
	DISTRIBUTION PLANT								
360.10	LAND AND LAND RIGHTS	65-R4	0	1,496,173.36	1,022,041	474,132	9,748	0.65	48.6
361.00	STRUCTURES AND IMPROVMENTS	60-R2.5	(10)	4,457,893.55	1,509,377	3,394,311	73,727	1.65	46.0
362.00	STATION EQUIPMENT	52-R2	(15)	100,792,637.54	30,916,216	84,995,316	2,295,433	2.28	37.0
364.00	POLES, TOWERS, AND FIXTURES	48-S0	(45)	193,793,678.56	108,962,347	172,038,488	4,466,396	2.30	38.5
365.00	OVERHEAD CONDUCTORS AND DEVICES	48-R2	(75)	180,861,758.25	105,672,071	210,836,003	6,121,679	3.38	34.4
366.00	UNDERGOUND CONDUIT	55-S4	0	1,728,495.59	702,456	1,026,041	33,382	1.93	30.7
367.00	UNDERGROUND CONDUCTORS AND DEVICES	44-S0.5	(5)	70,302,254.23	18,432,179	55,385,190	1,471,673	2.09	37.6
368.00	LINE TRANSFORMERS	40-R2	(20)	238,783,304.20	85,924,490	200,615,470	7,390,399	3.10	27.1
369.00	SERVICES	43-R1.5	(30)	83,111,706.05	53,033,588	55,011,631	1,652,284	1.99	33.3
370.00	METERS	40-R1.5	0	64,856,075.30	26,969,792	37,886,282	1,375,808	2.12	27.5
371.00	INSTALLATIONS ON CUSTOMER PREMISES	20-R0.5	(10)	18,276,458.22	14,013,191	6,090,914	434,205	2.38	14.0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	33-R1	(5)	53,640,293.35	23,870,883	32,451,424	1,229,177	2.29	26.4
	TOTAL DISTRIBUTION PLANT			1,012,100,728.20	471,028,631	860,205,202	26,553,911		

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	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)
	GENERAL PLANT								
390.10	STRUCTURES AND IMPROVEMENTS-TO OWNED PROPERTY	60-S0	(5)	32,199,743.43	8,632,707	25,177,023	534,030	1.66	47.1
390.20	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	30-R1	(5)	531,973.44	372,366	186,206	8,315	1.56	22.4
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	6,646,812.13	2,868,652	3,778,161	278,250	4.19	13.6
391.20	NON PC COMPUTER EQUIPMENT	5-SQ	0	11,291,984.97	7,567,325	3,724,660	1,144,982	10.14	3.3
391.30	CASH PROCESSING EQUIPMENT	10-SQ	0	817,574.88	532,363	285,212	45,133	5.52	6.3
391.40	PERSONAL COMPUTER EQUIPMENT	4-SQ	0	1,932,338.58	779,327	1,153,012	407,756	21.10	2.8
393.00	STORES EQUIPMENT	25-SQ	0	738,677.31	289,571	449,105	38,795	5.25	11.6
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	5,333,517.39	1,597,795	3,735,722	253,441	4.75	14.7
395.00	LABORATORY EQUIPMENT	15-SQ	0	3,202,201.94	1,586,334	1,615,868	877,936	27.42	1.8
396.00	POWER OPERATED EQUIPMENT	17-R5	0	270,941.73	99,450	171,492	17,258	6.37	9.9
397.10	COMMUNICATION EQUIPMENT - CARRIER	15-SQ	0	7,578,905.59	1,666,583	5,912,323	540,646	7.13	10.9
397.20	COMMUNICATION EQUIPMENT - REMOTE CONTROL	15-SQ	0	3,913,059.76	1,567,195	2,345,866	311,023	7.95	7.5
397.30	COMMUNICATION EQUIPMENT - MOBILE	15-SQ	0	4,659,773.21	1,806,815	2,852,958	340,124	7.30	8.4
398.00	MISCELLANEOUS EQUIPMENT	10-SQ	0	394,808.70	252,657	142,152	81,105	20.54	1.8
	TOTAL GENERAL PLANT			79,512,313.06	29,619,140	51,529,760	4,878,794		
	TOTAL DEPRECIABLE PLANT			3,605,547,550.97	1,807,546,044	2,562,215,572	96,337,040		
	NONDEPRECIABLE PLANT								
301.00	ORGANIZATION			44,455.58					
302.00	FRANCHISE AND CONSENTS			83,453.04	43,306				
303.00	MISCELLANEOUS INTANGIBLE PLANT			25,522,749.20	14,549,634				
310.10	LAND			10,478,524.56					
340.10	LAND			118,514.41					
350.10	LAND			1,168,238.43	329				
360.10	LAND			1,744,769.88					
389.10	LAND			2,811,100.83					
	TOTAL NONDEPRECIABLE PLANT			41,971,805.93	14,593,269				
	ACCOUNTS NOT STUDIED								
392.00	TRANSPORTATION EQUIPMENT			23,860,353.39	23,717,823				
	TOTAL ACCOUNTS NOT STUDIED			23,860,353.39	23,717,823				
	TOTAL ELECTRIC PLANT			3,671,379,710.29	1,845,857,136	2,562,215,572	96,337,040		

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

Attachment to Response to PSC-3 Question No. 20(c)
Responding Witness – Charnas

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
Intangible Plant					
301 Organization	44,456	0.00%	-	0.00%	-
302 Franchises and Consents	83,453	0.00%	-	0.00%	-
303 Misc. Intangible Plant	25,536,344	20.00%	5,107,269	20.00%	5,107,269
Total Intangible Plant	25,664,252		5,107,269		5,107,269
Steam Production Plant					
310.00 Land	10,874,263	0.00%	-	0.00%	-
311.00 Structures and Improvements					
5603 Tyrone Unit 3	5,540,781	0.00%	-	0.00%	-
5604 Tyrone Units 1&2	583,381	0.00%	-	0.00%	-
5613 Green River Unit 3	2,818,745	0.00%	-	0.00%	-
5614 Green River Unit 4	4,584,599	0.00%	-	0.00%	-
5615 Green River Units 1&2	2,596,587	0.00%	-	0.00%	-
5621 Brown Unit 1	4,703,190	0.60%	28,219	0.59%	27,749
5622 Brown Unit 2	2,102,892	0.08%	1,682	0.06%	1,262
5623 Brown Unit 3	20,393,087	0.54%	110,123	0.55%	112,162
5643 Pineville Unit 3	16,204	0.00%	-	0.00%	-
5650 Ghent Unit 1 Scrubber	24,301,127	2.65%	643,980	2.69%	653,700
5651 Ghent Unit 1	17,401,172	0.39%	67,865	0.40%	69,605
5652 Ghent Unit 2	16,011,013	0.50%	80,055	0.52%	83,257
5653 Ghent Unit 3	41,471,559	1.19%	493,512	1.19%	493,512
5654 Ghent Unit 4	29,847,745	1.41%	420,853	1.42%	423,838
5591 System Laboratory	805,716	1.54%	12,408	1.56%	12,569
	173,177,798		1,858,696		1,877,653
312.00 Boiler Plant Equipment					
5603 Tyrone Unit 3	12,871,948	3.99%	513,591	4.30%	553,494
5604 Tyrone Units 1&2	421,900	0.14%	591	0.00%	-
5613 Green River Unit 3	11,306,456	3.08%	348,239	3.39%	383,289
5614 Green River Unit 4	24,333,224	4.20%	1,021,995	4.50%	1,094,995
5615 Green River Units 1&2	127,047	2.18%	2,770	2.52%	3,202
5621 Brown Unit 1	35,820,003	2.98%	1,067,436	3.10%	1,110,420
5622 Brown Unit 2	29,419,949	3.01%	885,540	3.14%	923,786
5623 Brown Unit 3	86,541,309	2.80%	2,423,157	2.95%	2,552,969
5643 Pineville Unit 3	226,832	0.00%	-	0.00%	-
5650 Ghent Unit 1 Scrubber	86,520,141	3.87%	3,348,329	4.01%	3,469,458
5651 Ghent Unit 1	163,735,182	3.84%	6,287,431	4.02%	6,582,154
5652 Ghent Unit 2	89,995,577	2.33%	2,096,897	2.45%	2,204,892
5653 Ghent Unit 3	259,377,006	2.63%	6,821,615	2.76%	7,158,805
5654 Ghent Unit 4	231,652,822	2.79%	6,463,114	2.94%	6,810,593
5659 Coal Cars	7,647,232	2.41%	184,298	2.41%	184,298
5660 Ghent 3 Scrubber	118,758,718	3.87%	4,595,962	4.01%	4,762,225
	1,158,755,347		36,060,966		37,794,579
314.00 Turbogenerator Units					
5603 Tyrone Unit 3	4,717,000	3.44%	162,265	3.68%	173,586
5604 Tyrone Units 1&2	68,206	0.00%	-	0.00%	-

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
5613 Green River Unit 3	4,469,895	2.90%	129,627	3.14%	140,355
5614 Green River Unit 4	10,171,918	3.79%	385,516	4.05%	411,963
5621 Brown Unit 1	4,833,421	1.12%	54,134	1.16%	56,068
5622 Brown Unit 2	11,041,057	2.91%	321,295	3.04%	335,648
5623 Brown Unit 3	27,652,377	3.17%	876,580	3.31%	915,294
5651 Ghent Unit 1	25,577,290	2.23%	570,374	2.36%	603,624
5652 Ghent Unit 2	29,546,661	2.08%	614,571	2.19%	647,072
5653 Ghent Unit 3	40,076,564	2.03%	813,554	2.11%	845,616
5654 Ghent Unit 4	51,922,998	2.20%	1,142,306	2.30%	1,194,229
	210,077,388		5,070,221		5,323,453
315.00 Accessory Electric Equipment					
5603 Tyrone Unit 3	707,890	0.00%	-	0.00%	-
5604 Tyrone Units 1&2	99,211	0.00%	-	0.00%	-
5613 Green River Unit 3	781,287	0.00%	-	0.00%	-
5614 Green River Unit 4	1,147,502	1.46%	16,754	1.47%	16,868
5621 Brown Unit 1	3,329,621	2.10%	69,922	2.09%	69,589
5622 Brown Unit 2	997,856	0.48%	4,790	0.45%	4,490
5623 Brown Unit 3	6,453,917	0.54%	34,851	0.54%	34,851
5650 Ghent Unit 1 Scrubber	3,016,784	2.70%	81,453	2.73%	82,358
5651 Ghent Unit 1	7,703,537	0.55%	42,369	0.57%	43,910
5652 Ghent Unit 2	10,873,596	0.60%	65,242	0.63%	68,504
5653 Ghent Unit 3	25,991,761	1.03%	267,715	1.05%	272,913
5654 Ghent Unit 4	21,911,936	1.22%	267,326	1.24%	271,708
5660 Ghent 3 Scrubber	11,277,367	2.70%	304,489	2.73%	307,872
	94,292,263		1,154,910		1,173,064
316.00 Miscellaneous Plant Equipment					
5603 Tyrone Unit 3	526,592	3.12%	16,430	3.45%	18,167
5604 Tyrone Units 1&2	50,127	0.00%	-	0.00%	-
5613 Green River Unit 3	153,382	3.97%	6,089	4.28%	6,565
5614 Green River Unit 4	2,165,959	2.71%	58,697	3.04%	65,845
5615 Green River Units 1&2	84,750	0.00%	-	0.00%	-
5621 Brown Unit 1	424,540	2.26%	9,595	2.41%	10,231
5622 Brown Unit 2	106,658	0.71%	757	0.82%	875
5623 Brown Unit 3	4,317,609	2.33%	100,600	2.47%	106,645
5650 Ghent Unit 1 Scrubber	985,410	2.87%	28,281	3.00%	29,562
5651 Ghent Unit 1	1,718,709	1.38%	23,718	1.51%	25,953
5652 Ghent Unit 2	1,500,525	1.07%	16,056	1.17%	17,556
5653 Ghent Unit 3	3,150,438	1.40%	44,106	1.41%	44,421
5654 Ghent Unit 4	6,247,981	2.03%	126,834	2.12%	132,457
5591 System Laboratory	2,229,677	2.74%	61,093	2.96%	65,998
	23,662,356		492,257		524,276
317.00 Asset Retirement Obligations - Steam *	9,249,179				
Total Steam	1,680,088,593		44,637,050		46,693,026

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
Hydraulic Production Plant					
5691 Dix Dam					
330.10 Land Rights	879,311	0.00%	0	0.00%	-
331.00 Structures and Improvements	453,195	1.29%	5,846	1.31%	5,937
332.00 Reservoirs, Dams & Waterways	9,025,249	0.72%	64,982	0.73%	65,884
333.00 Water Wheels, Turbines and Generators	436,634	0.66%	2,882	0.68%	2,969
334.00 Accessory Electric Equipment	85,383	0.83%	709	0.93%	794
335.00 Misc. Power Plant Equipment	101,513	3.55%	3,604	4.21%	4,274
336.00 Roads, Railroads and Bridges	46,976	0.00%	0	0.00%	-
337.00 Asset Retirement Obligation - Hydro *	4,970				
	11,033,232		78,022		79,858
Other Production Plant					
340.10 Land Rights - 5645 Brown CT 9 Gas Pipeline	176,409	2.97%	5,239	3.62%	6,386
340.20 Land	118,514	0.00%	-	0.00%	-
341.00 Structures and Improvements					
5697 Paddy's Run Generator 13	1,910,328	3.03%	57,883	3.33%	63,614
5635 Brown CT 5	775,082	3.04%	23,562	3.34%	25,888
5636 Brown CT 6	192,814	3.05%	5,881	3.40%	6,556
5637 Brown CT 7	544,966	2.93%	15,968	3.24%	17,657
5638 Brown CT 8	2,012,655	2.60%	52,329	2.87%	57,763
5639 Brown CT 9	4,641,055	2.60%	120,667	2.87%	133,198
5640 Brown CT 10	1,865,718	2.61%	48,695	2.87%	53,546
5641 Brown CT 11	1,858,754	2.72%	50,558	3.00%	55,763
0470 Trimble County CT 5	3,740,231	3.14%	117,443	3.47%	129,786
0471 Trimble County CT 6	3,588,684	3.12%	111,967	3.44%	123,451
0474 Trimble County CT 7	3,559,155	3.32%	118,164	3.69%	131,333
0475 Trimble County CT 8	3,548,852	3.32%	117,822	3.69%	130,953
0476 Trimble County CT 9	3,655,976	3.32%	121,378	3.69%	134,906
0477 Trimble County CT 10	3,653,030	3.32%	121,281	3.69%	134,797
5696 Haefling Units 1,2,&3	434,853	6.47%	28,135	8.89%	38,658
	35,982,154		1,111,734		1,237,867
342.00 Fuel Holders, Producers and Accessories					
5697 Paddy's Run Generator 13	1,995,101	3.11%	62,048	3.37%	67,235
5635 Brown CT 5	727,929	3.11%	22,639	3.36%	24,458
5636 Brown CT 6	146,515	2.92%	4,278	3.16%	4,630
5637 Brown CT 7	145,745	2.92%	4,256	3.16%	4,606
5638 Brown CT 8	19,613	2.63%	516	2.86%	561
5639 Brown CT 9	1,932,187	2.65%	51,203	2.87%	55,454
5640 Brown CT 10	31,738	2.63%	835	2.85%	905
5641 Brown CT 11	52,430	2.74%	1,437	2.96%	1,552
5645 Brown CT 9 Gas Pipeline	8,106,131	2.57%	208,328	2.79%	226,161
0470 Trimble County CT 5	239,584	3.21%	7,691	3.48%	8,338
0471 Trimble County CT 6	239,246	3.21%	7,680	3.48%	8,326
0473 Trimble County CT Pipeline	4,850,115	3.23%	156,659	3.51%	170,239
0474 Trimble County CT 7	578,059	3.42%	19,770	3.74%	21,619

Kentucky Utilities Company
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Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
0475 Trimble County CT 8	576,386	3.42%	19,712	3.74%	21,557
0476 Trimble County CT 9	593,786	3.42%	20,307	3.74%	22,208
0477 Trimble County CT 10	622,873	3.42%	21,302	3.74%	23,295
5696 Haefling Units 1,2,&3	227,578	0.00%	-	0.48%	1,092
	21,085,015		608,659		662,235
343.00 Prime Movers					
5697 Paddy's Run Generator 13	17,421,691	3.62%	630,665	4.49%	782,234
5635 Brown CT 5	13,182,503	3.65%	481,161	4.60%	606,395
5636 Brown CT 6	30,423,304	3.55%	1,080,027	4.52%	1,375,133
5637 Brown CT 7	30,024,907	3.58%	1,074,892	4.56%	1,369,136
5638 Brown CT 8	26,344,009	3.30%	869,352	4.13%	1,088,008
5639 Brown CT 9	21,502,647	3.23%	694,536	4.00%	860,106
5640 Brown CT 10	19,670,646	3.26%	641,263	4.04%	794,694
5641 Brown CT 11	34,931,891	3.41%	1,191,177	4.17%	1,456,660
0470 Trimble County CT 5	30,564,294	3.72%	1,136,992	4.66%	1,424,296
0471 Trimble County CT 6	30,443,723	3.72%	1,132,506	4.66%	1,418,677
0474 Trimble County CT 7	22,773,708	3.91%	890,452	5.17%	1,177,401
0475 Trimble County CT 8	22,568,161	3.91%	882,415	5.16%	1,164,517
0476 Trimble County CT 9	22,401,560	3.91%	875,901	5.16%	1,155,920
0477 Trimble County CT 10	22,385,894	3.91%	875,288	5.16%	1,155,112
	344,638,937		12,456,629		15,828,290
344.00 Generators					
5697 Paddy's Run Generator 13	5,185,636	2.94%	152,458	2.96%	153,495
5635 Brown CT 5	2,831,528	2.94%	83,247	2.96%	83,813
5636 Brown CT 6	3,712,620	2.76%	102,468	2.78%	103,211
5637 Brown CT 7	3,722,788	2.76%	102,749	2.78%	103,494
5638 Brown CT 8	4,953,961	2.46%	121,867	2.49%	123,354
5639 Brown CT 9	5,452,041	2.31%	125,942	2.36%	128,668
5640 Brown CT 10	4,944,423	2.46%	121,633	2.49%	123,116
5641 Brown CT 11	5,187,040	2.53%	131,232	2.56%	132,788
0470 Trimble County CT 5	3,763,275	3.04%	114,404	3.06%	115,156
0471 Trimble County CT 6	3,757,947	3.04%	114,242	3.06%	114,993
0474 Trimble County CT 7	2,950,282	3.26%	96,179	3.26%	96,179
0475 Trimble County CT 8	2,937,930	3.26%	95,777	3.26%	95,777
0476 Trimble County CT 9	2,957,520	3.26%	96,415	3.26%	96,415
0477 Trimble County CT 10	2,954,149	3.26%	96,305	3.26%	96,305
5696 Haefling Units 1,2,&3	4,023,002	0.00%	-	0.00%	-
	59,334,142		1,554,918		1,566,764
345.00 Accessory Electric Equipment					
5697 Paddy's Run Generator 13	2,456,320	2.88%	70,742	3.04%	74,672
5635 Brown CT 5	1,332,167	2.89%	38,500	3.04%	40,498
5636 Brown CT 6	1,354,816	2.71%	36,716	2.86%	38,748
5637 Brown CT 7	1,347,700	2.71%	36,523	2.86%	38,544
5638 Brown CT 8	1,799,436	2.41%	43,366	2.56%	46,066
5639 Brown CT 9	3,226,186	2.32%	74,848	2.49%	80,332
5640 Brown CT 10	1,804,419	2.44%	44,028	2.58%	46,554
5641 Brown CT 11	916,326	2.48%	22,725	2.63%	24,099

Kentucky Utilities Company
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Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
0470 Trimble County CT 5	1,677,092	2.98%	49,977	3.14%	52,661
0471 Trimble County CT 6	1,674,719	2.98%	49,907	3.14%	52,586
0474 Trimble County CT 7	3,146,235	3.19%	100,365	3.35%	105,399
0475 Trimble County CT 8	3,137,127	3.19%	100,074	3.35%	105,094
0476 Trimble County CT 9	3,231,827	3.19%	103,095	3.35%	108,266
0477 Trimble County CT 10	3,229,223	3.19%	103,012	3.35%	108,179
5696 Haefling Units 1,2,&3	623,419	0.00%	-	0.00%	-
	30,957,013		873,877		921,698
346.00 Miscellaneous Plant Equipment					
5697 Paddy's Run Generator 13	1,089,550	3.20%	34,866	3.70%	40,313
5635 Brown CT 5	2,139,353	3.20%	68,459	3.71%	79,370
5636 Brown CT 6	48,960	3.33%	1,630	3.93%	1,924
5637 Brown CT 7	35,647	3.23%	1,151	3.76%	1,340
5638 Brown CT 8	230,069	2.77%	6,373	3.20%	7,362
5639 Brown CT 9	760,255	2.77%	21,059	3.19%	24,252
5640 Brown CT 10	274,391	2.85%	7,820	3.30%	9,055
5641 Brown CT 11	548,588	3.22%	17,665	3.76%	20,627
0470 Trimble County CT 5	28,964	3.73%	1,080	4.81%	1,393
0474 Trimble County CT 7	8,889	3.50%	311	4.13%	367
0475 Trimble County CT 8	8,861	3.50%	310	4.13%	366
0476 Trimble County CT 9	9,114	3.50%	319	4.14%	377
0477 Trimble County CT 10	9,106	3.49%	318	4.13%	376

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
5696 Haefling Units 1,2,&3	35,805	0.00%	-	1.97%	705
	5,227,550		161,362		187,829
347.00 Asset Retirement Obligations Othe Prod *	70,990				
Total Other Production	497,590,725		16,772,417		20,411,068
Transmission Plant					
350.1 Land Rights	23,341,455	0.98%	228,746	1.12%	261,424
350.2 Land	1,232,665	0.00%	-	0.00%	-
352.1 Struct. and Impr. Non Sys Control	7,228,687	1.54%	111,322	1.75%	126,502
352.2 Struct. and Impr. Sys Control	1,154,520	1.43%	16,510	1.63%	18,819
353.1 Station Equipment	175,730,576	1.98%	3,479,465	2.46%	4,322,972
353.2 Syst Control/Microwave Equip	14,749,281	0.46%	67,847	0.56%	82,596
354 Towers & Fixtures	63,279,467	1.21%	765,682	1.30%	822,633
355 Poles & Fixtures	100,687,186	2.28%	2,295,668	2.91%	2,929,997
356 Overhead Conductors and Devices	132,799,950	1.79%	2,377,119	2.05%	2,722,399
357 Underground Conduit	448,760	2.60%	11,668	3.19%	14,315
358 Underground Conductors & Devices	1,114,762	1.26%	14,046	1.45%	16,164
359 Transmission ARO's *	11,027				
Total Transmission Plant	521,778,335		9,368,072		11,317,822
Distribution Plant					
360.1 Land Rights	1,496,173	0.65%	9,725	0.70%	10,473
360.2 Land	1,998,646	0.00%	-	0.00%	-
361 Structures and Improvements	5,058,913	1.65%	83,472	2.00%	101,178
362 Station Equipment	103,445,343	2.28%	2,358,554	2.82%	2,917,159
364 Poles Towers & Fixtures	212,853,185	2.30%	4,895,623	3.25%	6,917,729
365 Overhead Conductors and Devices	199,717,218	2.70%	5,392,365	4.23%	8,448,038
366 Underground Conduit	1,546,234	1.93%	29,842	2.06%	31,852
367 Underground Conductors & Devices	86,404,514	2.09%	1,805,854	2.86%	2,471,169
368 Line Transformers	248,482,289	3.10%	7,702,951	3.83%	9,516,872
369 Services	83,122,059	1.99%	1,654,129	2.57%	2,136,237
370 Meters	65,364,852	1.76%	1,150,421	2.79%	1,823,679
371 Installations on Customer Premises	18,284,592	2.38%	435,173	3.05%	557,680
373 Street Lighting & Signal Systems	53,771,544	2.29%	1,231,368	3.16%	1,699,181
374 Asset Retirement Cost - Distribution *	18,610				-
Total Distribution Plant	1,081,564,173		26,749,479		36,631,247

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
General Plant					
389.2 Land	2,575,973	0.00%	-	0.00%	-
390.1 Structures & Improvements	29,901,859	1.66%	496,371	2.30%	687,743
390.2 Improvements to Leased Property	531,973	1.56%	8,299	2.04%	10,852
391.1 Office Furniture & Equipment	6,548,609	4.19%	274,387	4.19%	274,387
391.2 Non PC Computer Equipment	10,163,473	10.14%	1,030,576	10.14%	1,030,576
391.3 Cash Processing Equpment	448,191	23.26%	104,249	23.26%	104,249
391.4 Personal Computer Equipment	2,486,306	15.47%	384,631	21.10%	524,610
392 Transportation Equipment	18,955,798	20.00%	3,791,160	20.00%	3,791,160
393 Stores Equipment	735,053	5.25%	38,590	5.25%	38,590
394 Tool, Shop & Garage Equipment	5,473,498	4.75%	259,991	4.75%	259,991
395 Laboratory Equipment	3,160,382	27.42%	866,577	27.42%	866,577
396 Power Operated Equipment	270,942	6.37%	17,259	6.62%	17,936
397.10 Communication Equipment - Carrier	8,835,076	7.13%	629,941	7.13%	629,941
397.20 Communication Equip. - Remote Contro	3,913,060	7.95%	311,088	7.95%	311,088
397.30 Communication Equipment - Mobile	5,087,846	7.30%	371,413	7.30%	371,413
398 Misc Equipment	373,590	20.54%	76,735	20.54%	76,735
Total General Plant	99,461,628		8,661,267		8,995,849
Total Plant in Service	3,917,180,938				
Total Annual Depreciation excluding ARO amounts			111,373,576		129,236,140
Less Amounts not included in Income Statement Depreciation					
Coal Cars			184,298		184,298
Brown Gas Pipeline			208,328		226,161
TC Gas Pipeline			156,659		170,239
Account 139200 Transportation Equip.			3,791,160		3,791,160
Subtotal			4,340,444		4,371,858
Total Annualized Depr. less ARO and Amts not in Inc. St. Depr.			107,033,132		124,864,282
Less ECR Depreciation			12,751,570		13,327,774
Total Annualized Depreciation excluding ECR and ARO			$ 94,281,562		$ 111,536,507

* Represents list of ARO assets. Please note these amounts are not included in the calculation.

Kentucky Utilities Company - ECR April 2008

2001 Plan		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
Project 16 -- NOx Ghent Plant					
Ghent 4	1/1/2002				
Investments	4,551,149	2 79%	126,977 06	2 94%	133,803 78
Retirements, Original Cost	(44,311)		(960 00)		(960 00)
Ghent 2	3/1/2002				
Investments	5,224,392	2 33%	121,728 33	2 45%	127,997 60
Retirements, Original Cost	(41,180)		(756 00)		(756 00)
Project 17 -- SCRs and NOx Modifications					
Tyrone 3 -- Original In-service amount	11/1/2001				
Investments	1,262,166	3 99%	50,360 42	4 30%	54,273 14
Retirements, Original Cost	(216,581)		(4,608 00)		(4,608 00)
Tyrone 3 -- December 2004 Additions	12/1/2004				
Investments	87,293	3 99%	3,482 99	4 30%	3,753 60
Green River 3 Original Investments	7/1/2002				
Investments	1,358,579	3 08%	41,844 23	3 39%	46,055 83
Retirements, Original Cost	(149,233)		(2,892 00)		(2,892 00)
Green River 3 December 2004 Additions	12/1/2004				
Investments	269,265	3 08%	8,293 36	3 39%	9,128 08
Brown 2 Original Investment	12/1/2002				
Investments	1,937,045	3 01%	58,305 05	3 15%	61,016 92
Retirements, Original Cost	(918,431)		(26,448 00)		(26,448 00)
Brown 2 December 2004 Additions	12/1/2004				
Investments	776,167	3 01%	23,362 62	3 15%	24,449 25
Ghent 3 Original Investment	3/1/2004				
Investments	71,476,281	2 63%	1,879,826 19	2 76%	1,972,745 36
Retirements, Original Cost	(172,301)		(3,828 00)		(3,828 00)
Ghent 3 December 2004 Additions	12/1/2004				
Investments	2,958,119	2 63%	77,798 53	2 76%	81,644 08
Ghent 3 April 2005 Additions	3/1/2004				
Investments	2,971,181	2 63%	78,142 07	2 76%	82,004 61
Ghent 4 Original Investment	4/1/2004				
Investments	53,324,763	2 79%	1,487,760 89	2 94%	1,567,748 03
Retirements, Original Cost	(216,248)		(4,668 00)		(4,668 00)
Ghent 4 December 2004 Additions	12/1/2004				
Investments	3,288,376	2 79%	91,745 70	2 94%	96,678 26
Ghent 4 April 2005 Additions	4/1/2004				
Investments	3,518,957	2 79%	98,178 91	2 94%	103,457 34
Brown 3 Original Investment	5/1/2004				
Investments	2,102,228	2 80%	58,862 38	2 95%	62,015 73
Retirements, Original Cost	(848,647)		(33,180 00)		(33,180 00)
Brown 3 December 2004 Additions	12/1/2004				
Investments	364,407	2 80%	10,203 40	2 95%	10,750 01
Brown 3 April 2005 Additions	5/1/2004				
Investments	754	2 80%	21 11	2 95%	22 24
Ghent 1 Original Investment	5/1/2004				
Investments	56,004,868	3 84%	2,150,586 93	4 02%	2,251,395 69
Retirements, Original Cost	(113,614)		(3,540 00)		(3,540 00)
Ghent 1 December 2004 Additions	12/1/2004				
Investments	9,617,570	3 84%	369,314 69	4 02%	386,626 31

Kentucky Utilities Company - ECR April 2008

		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
Ghent 1 April 2005 Additions	5/1/2004				
Investments	3,520,209	3.84%	135,176.02	4.02%	141,512.40
Ghent 2 - December 2004 Addition	12/1/2004				
Investments	13,192	2.33%	307.37	2.45%	323.20
GH1 SCR Catalyst Addition May 2006	5/1/2006				
Investments	2,112,857	3.84%	81,133.70	4.02%	84,936.84
2001 Plan Additions	226,739,818				
2001 Plan Retirements	(2,720,546)				
2003 Plan					
Project 18 -- Ghent Ash Pond					
	12/1/2003				
Investments	16,148,295	2.79%	450,537.43	2.94%	474,759.87
2005 Plan					
Project 19 - Ash Handling at Ghent 1 and Ghent Station					
Ghent Station - Ash Pipe Repl Addition 4/30/06	4/1/2006				
Investments	398,915	2.79%	11,129.74	2.94%	11,728.11
Retirements, Original Cost	(292,425)		(6,312.00)		(6,312.00)
Project 21 - FGDs					
Ghent 3	6/1/2007				
Investments-Total	136,503,019	3.87%	5,282,666.84	4.01%	5,473,771.06
Retirements, Original Cost	(4,047,526)		(89,220.00)		(89,220.00)
Brown Training Bldg/Warehouse	12/1/2007				
Investments-Total	7,334,344	2.80%	205,361.63	2.95%	216,363.14
Retirements -- Original Cost	(74,700)		(2,916.00)		(2,916.00)
2005 Plan Additions	144,236,278				
2005 Plan Retirements	(4,414,651)				
2006 Plan					
Project 25 -- Mercury Monitors					
Tyrone 3	12/31/2006				
Investments	18,149	3.99%	724.13	4.30%	780.39
Brown 3	12/31/2006				
Investments	68,158	2.80%	1,908.42	2.95%	2,010.66
Ghent 4	12/31/2006				
Investments	45,279	2.79%	1,263.29	2.94%	1,331.21
Green River 4	12/31/2006				
Investments	18,164	4.20%	762.87	4.50%	817.36
CEMS Stackvision EDR Upgrade	10/1/2007				
Investments	115,540	20.00%	23,108.00	20.00%	23,108.00
Project 27 -- ESP					
Brown	6/15/2006				
Investments	46,715	2.80%	1,308.03	2.95%	1,378.10
Retirements, Original Cost	(32,691)		(1,284.00)		(1,284.00)
2006 Plan Additions	312,005				
2006 Plan Retirements	(32,691)				
Total Additions	387,436,395.58	Total	12,751,570.32		13,327,774.21
Total Retirements	(7,167,887.87)				
	380,268,507.71				

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 21

Responding Witness: John J. Spanos

Q-21. Refer to KU's response to Staffs Second Request, Item 97. Is John Spanos saying that KU's proposed depreciation rates only recover "non-legal" asset removal costs and do not include recovery of ARO's (legal asset removal costs)? Explain.

A-21. That is correct. Mr. Spanos is saying that KU's proposed depreciation rates do not include recovery of AROs. Depreciation expense for AROs is offset by regulatory credits and therefore is excluded from Mr. Spanos' proposed depreciation rates in this proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 22

Responding Witness: Shannon L. Charnas

Q-22. Refer to KU's response to Staffs Second Request, Item 98.

a. In response to Item 98(b), KU provides information for years 2003-2007. Can the amounts requested for years prior to 2003 be calculated even though they were not recorded? If yes, provide the amounts. If no, explain why.

b. For each year shown in Item 98(b) (2003-2007), the amount of net removal costs included in accumulated depreciation has increased. If not already provided in response to (a) above, provide documentation that net removal costs included in accumulated depreciation have never decreased from one year to the next from the time that KU began recovering asset removal costs through depreciation stated as a percentage of original plant costs.

c. Item 98(c) requested a description of the impact on KU if it was required to reclassify asset removal costs from accumulated depreciation to a regulatory liability account for regulatory reporting purposes as it does for GAAP reporting purposes. KU's response discusses the appropriateness of rate recovery of asset removal costs, but does not directly respond to the question asked. Identify and discuss all favorable and unfavorable consequences to KU if the Commission were to require reclassification of KU's asset removal costs from accumulated depreciation to a regulatory liability account for regulatory reporting purposes.

A-22. a. No, the estimated cost of removal prior to 2003 cannot be calculated. The data needed for this calculation is not available as any computation would be a factor of plant in service and an estimated cost of removal rate. The estimated cost of removal rate was not historically broken out separately until 2003, when SFAS No. 143 was adopted, and was based on a depreciation study completed as of December 31, 2002 which was provided in the Company's most recent base rate case.

b. Documentation detailing cost of removal separate from accumulated depreciation is not available prior to 2003. The depreciation rates have not changed since 1999 and the Company continues to add assets at a rate greater than assets are retired. An increased amount of assets results in increasing cost of removal booked to the reserve. The increase by year varies based on the amount spent on removal costs. See Case No. 2007-00565, Response to the Attorney General's Initial Requests for Information dated February 4, 2008, Question No. 96 for detail of the annual depreciation and cost of removal charges.

c. If the Commission were to require the reclassification of KU's costs of removal from accumulated depreciation to a regulatory liability account for regulatory reporting purposes, a favorable consequence would be that it would create consistency between GAAP reporting and regulatory reporting. An unfavorable consequence would be the inconsistency that would be created with prior years' regulatory reporting. There should be no impact on the ratemaking treatment of the costs of removal, regardless of where they are recorded, since a basic concept behind including cost of removal as a component of deprecation rates is to prevent generational inequities. No other consequences have been identified by KU.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 23

Responding Witness: John J. Spanos

Q-23. Refer to KU's response to Staffs Second Request, Item 85(b).

a. The order of the Pennsylvania Public Utility Commission does not identify that the ELG method was proposed. Provide the relevant section of the testimony of Mr. Spanos in the Pennsylvania case which reflects that the depreciation proposal of the utility was based on the ELG method.

b. In the order of the Indiana Commission, identify whether there is any support for the decision to adopt ELG other than the first full paragraph on page 55 of the order which states that the Commission had "on numerous occasions accepted the use of the ELG methodology."

A-23. a. The order of the Pennsylvania Public Utility Commission did not specifically identify the utilization of the ELG procedure because this procedure is utilized by almost all studies proposed in the state. Nonetheless, the attached section of Mr. Spanos' testimony sets forth his proposal of the ELG procedure.

b. There is support for the decision. The order of the Indiana Commission, accepts Mr. Spanos' proposal of depreciation rates which were developed using the ELG procedure. Attached is the section of Mr. Spanos' testimony which sets forth his proposal of the ELG procedure.

PSW Statement No. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF
JOHN J. SPANOS

ON BEHALF OF
PENNSYLVANIA SUBURBAN WATER COMPANY

CONCERNING DEPRECIATION

DOCKET NO. R-00038805

NOVEMBER 2003

Exhibit No. 6-A, Part II, titled "Depreciation Study - Calculated Annual Depreciation Accruals Related to Utility Plant in Service at June 30, 2004," includes the results of the depreciation study as related to the estimated original cost at June 30, 2004. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations.

Q. What was the purpose of your depreciation study?

A. The purpose of the depreciation study was to estimate the annual depreciation accruals related to utility plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve at June 30, 2004.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent water rate proceeding in Docket No. R-00016750?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used for over fifteen years. For Accounts 340, 341.2, 342, 343, 346 and 347, the claim is based on the straight line remaining life method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. The equal life group procedure is used in the current proceeding for all depreciable accounts and installation years. The equal life group procedure also was used in this same manner in the Company's last rate proceeding.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over seventeen years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserves approved by the Commission at Docket No. R-850174.

Q. How was the book reserve used in the calculation of annual depreciation?

A. The book reserve by account was allocated to vintages to determine original cost less accrued depreciation by vintage. The total annual accrual is the sum of the results of dividing the original costs less accrued depreciation by the vintage composite remaining lives.

Q. How was the book reserve at June 30, 2004 estimated?

A. The book reserve at June 30, 2004, by account, was projected by adding estimated accruals, salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve at June 30, 2003. Annual accruals were estimated using the annual accruals calculated as of June 30, 2003. For most accounts, salvage and cost of removal were estimated by (1) expressing actual salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percents to the projected retirements by account. For mains and services, the historical percents derived in the manner described above

PETITIONER'S EXHIBIT T (JJS)

TESTIMONY OF JOHN J. SPANOS
VICE PRESIDENT OF GANNETT FLEMING
ON BEHALF OF
PSI ENERGY, INC.
CAUSE NO. 42359 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming, Inc.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING, INC.?

A. I have been associated with the firm since college graduation in June, 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am Vice President of its Valuation and Rate Division.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1989 through 2001 and considered estimates for other electric companies. I also used the Demolition Cost Estimates prepared by Sargent & Lundy, Petitioner's Exhibit U-1 (AWW-1) through Petitioner's Exhibit U-6 (AWW-6) for steam production accounts.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the equal life group procedure. The calculation of annual depreciation accrual rates were developed as of September 30, 2002.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE THE EQUAL LIFE GROUP PROCEDURE FOR CALCULATING REMAINING LIFE ACCRUAL RATES.

A. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. This procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

The equal life group procedure allocates the capital cost of a group property to annual expense in accordance with the consumption of the service value of the group. The more timely return of plant investment accomplished by fully accruing each item's cost during its service life not only reduces the risk of incomplete capital recovery, but also results in less investment-related cost over the life span of a depreciable group. Under the equal life group procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. Amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these assets because periodic inventories are required to

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 24

Responding Witness: Valerie L. Scott

Q-24. Refer to KU's response to Staff's Second Request, Item 99. At Item 99, KU identifies test year compensated absences of $10,657,618 included in the test year operating labor charges. Are the $10,657,618 compensated absence expenses included in the operating labor charge of $73,184,131 used to calculate the *pro forma* payroll adjustment shown at Volume 4 of 5 of KU's application at the Rives Testimony, Exhibit 1, Schedule 1 15, page 2 of 4? If no, explain why they are excluded from the determination of the *pro forma* payroll adjustment.

A-24. Yes. The test year compensated absences of $10,657,618 are included in the test year operating labor charge of $73,184,131.

KENTUCKY UTILITIES COMPANY

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CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 25

Responding Witness: Paula H. Pottinger, Ph.D. / Valerie L. Scott

Q-25. Refer to Volume 4 of 5 of KU's application at the Rives Testimony, Exhibit 1, Reference Schedule 1.15, page 2 and KU's response to Staff's Second Request, Item 100.

a. Do the amounts included in the calculation of *pro forma* payroll include a provision for compensated absences? If no, explain the relevance of the schedule labeled as "Estimated Vacation Liability Report" provided by KU at Item 100(b-1), page 2 If yes, provide a schedule separating compensated absences included in the "Grand Total" *pro forma* payroll for each account shown at Item 100(a), page 1.

b. State the amount of leave time an employee is allowed to carry forward.

c. Describe how KU estimates the increase or decrease in employee leave time carry-forward balances when calculating *pro forma* payroll costs.

d. Identify all employee positions included on these schedules that were vacant as of April 30, 2008.

e. For each employee position identified in (d) above, state whether or not the position is currently vacant.

f. For all employee positions identified in (d) above, state when KU expects to fill the position.

g. Identify all employee positions included on these schedules that were vacant as of the date of KU's response to this data request.

h. For each employee position identified in (g) above, state when KU expects to fill the position.

A-25. a. A provision for compensated absences is not included in the calculation of *pro forma* payroll costs. The adjustment at Reference Schedule 1.15, page 2 is to adjust test year labor to reflect annualized base labor at April 30, 2008.

b. Employees are allowed to carry forward one week of vacation time.

c. Carry-forward balances are not considered when calculating the *pro forma* payroll costs. The adjustment at Reference Schedule 1.15, page 2 is to adjust test year labor to reflect annualized base labor at April 30, 2008.

d. No vacant employee positions were included in the labor costs. Labor costs were based on actual employee counts.

e. No vacant employee positions were identified in (d) above.

f. No vacant employee positions were identified in (d) above.

g. No vacant employee positions were included in the labor costs. Labor costs were based on actual employee counts.

h. No vacant employee positions were identified in (d) above.

KENTUCKY UTILITIES COMPANY

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Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 26

Responding Witness: Valerie L. Scott / Shannon L. Charnas

Q-26. Refer to KU's response to Staff's Second Request, Items 100(a) and 106(a).

a. State the amount of the payroll costs included in each account listed in Item 106(a).

b. Identify where each amount identified in (a) above is included in *pro forma* labor as listed in Item 100(a).

c. Explain why it is appropriate to recover labor-related storm damage expenses identified in (a) above through the 9-year amortization as shown in Volume 4 of 5 of KU's application of the Rives Testimony at Exhibit 1, Reference Schedule 1.18 and also through the *pro forma* labor costs shown at Item 100(a).

d. Identify by account number and account title, and provide a description of all amounts included in test year storm repair expenses as shown at Item 106(a) for which there is a separate provision for recovery in the *pro forma* operating expenses totaling $862,196,011 as stated at Volume 3 of 5 of KU's application at Tab 42, e.g., payroll taxes, pensions, transportation costs, depreciation, etc.

A-26. a See attached.

b. See attached.

c. The Company is not recovering the same labor costs in both Reference Schedules 1.18 and 1.15.

Rives Exhibit 1, Reference Schedule 1.18 is the adjustment to "normalize" storm damage expenses through a 9-year historic average adjusted for inflation in a manner consistent with the approach used by the Commission in previous cases. The storm damage normalization adjustment does not reflect a 9-year amortization. The purpose of the storm damage adjustment is to adjust the actual level of the expenses, including labor costs incurred during the test year to an average or normalized amount due to the year-to-year fluctuations associated with this category of expenses.

Rives Exhibit 1, Reference Schedule 1.15 is the adjustment to reflect annualized labor and labor-related costs in a manner consistent with the approach used by the Commission in previous cases. The purpose of the adjustment is to adjust test year operating labor to an annualized level. This adjustment only reflects the additional expense the Company would have incurred had employees been paid throughout the year at the same rate they were paid at test year end.

d. There is not a separate provision for recovery in the *pro forma* operating expenses for storm damage expenses. The $5,708,101 (total Company) expenses listed in The Commission's Second Data Request Question No. 106(a) are the storm damage expenses incurred during the test year as indicated on Rives Exhibit 1, Reference Schedule 1.18, line 2. Pursuant to the *pro forma* adjustment to normalize storm damage expenses (based on a 9-year historical average), the test year amount of $5,708,101 was reduced by $2,902,717 which results in recovery of $2,805,384 (total Company) of storm damage expenses. The KU jurisdictional amount is $2,639,782 which is included in line 8, Adjusted, of Volume 3 of 5 of KU's application at Tab 42.

Kentucky Utilities Company
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a.) Storm Damage Labor Expense by Account; listed in PSC 2-106(a)

Account	Labor Expenses
583001	$ 388,927
584001	2,674
588100	90,583
592100	-
593002	2,046,702
593004	10,648
594001	1,526
595100	1,462
596100	-
925100	-
	$ 2,542,522

b.)

Storm Damage Labor Expenses from PSC-2 Question No. 100(a)

FERC Account	Charged from KU			Charged from Servco			Total Included on Line 6 of PSC-2 Question No. 100(a)	Charged from LG&E[1]			Grand Total
	Straight Time	OT and Premium	Total	Straight Time	OT and Premium	Total		Straight Time	OT and Premium	Total	
583	$ 68,187	$ 233,434	$ 301,621	$ 15,529	$ 7,264	$ 22,793	$ 324,414	$ 7,357	$ 57,156	$ 64,513	$ 388,927
584	475	2,199	2,674	-	-	-	2,674	-	-	-	2,674
588	49,815	39,161	88,976	1,607	-	1,607	90,583	-	-	-	90,583
593	619,358	1,408,249	2,027,607	18,647	703	19,350	2,046,957	6,881	3,512	10,393	2,057,350
594	-	1,526	1,526	-	-	-	1,526	-	-	-	1,526
595	-	1,462	1,462	-	-	-	1,462	-	-	-	1,462
	$ 737,835	$ 1,686,031	$ 2,423,866	$ 35,783	$ 7,967	$ 43,750	$ 2,467,616	$ 14,238	$ 60,668	$ 74,906	$ 2,542,522

[1] LG&E Labor charged to KU is not included in Rives Exhibit 1, Schedule 1.15, page 2 of 4

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 27

Responding Witness: Chris Hermann / Shannon L. Charnas

Q-27. Refer to KU's response to Staffs Second Request, Item 106.

a. Describe the accounting process used to record restoration services provided by KU to other electric providers. This description should discuss how these restoration costs are determined and how reimbursements to KU for these services are recorded.

b. Identify all restoration costs and reimbursements included in KU's test year operations.

A-27. a. When KU is approached to provide restoration services to other electric providers, a project and task are created in Oracle to record the costs. The task number is set up with the mutual assistance receivable GL account number (FERC 143024). All costs of the services KU provides to the other electric provider are recorded on this project and task.

When KU's work is completed and all charges have been posted to the project, a listing of the costs is prepared by expenditure type (labor, materials, etc.). This list is then used to create an invoice to send to the other electric provider.

b. KU provided restoration services to Kentucky Power, a subsidiary of AEP, of Columbus, OH during the test year. The total amount billed and reimbursed was $12,370. Neither the expenses nor offsetting reimbursement are included in net operating income.

There were no restoration services billings to Kentucky Utilities in the test year.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 28

Responding Witness: Paula H. Pottinger, Ph.D.

Q-28. Refer to KU's response to Staffs Second Request, Item 102. Provide a calculation of each test year "other compensation" amount listed for each executive employee and provide an explanation for how the level of compensation was determined.

A-28. The Company is not seeking recovery in rates for the cost associated with "other compensation". Target short-term and long-term awards are communicated as a percent of salary based on respective external market data. Actual short-term and long-term payments are based on performance against pre-determined goals.

An example of a short-term and long-term incentive calculation is attached.

Short-Term Incentive
Per the attached plan, pre-determined goals for the short-term incentive plan include annual financial and individual objectives. Financial and individual objectives are weighted based on job level and responsibilities.

Long-Term Incentive
Per the attached plan, target awards are made annually for a three-year performance cycle. In the case of the LG&E Energy Corp. Performance Unit Plan, performance is based on annual pre-determined Value-Added objectives. At the end of the three-year performance cycle, long-term incentive payments are calculated based on the average Value-Added performance results for the three-year period.

Perquisites
Perquisites were determined in accordance with market practice and vary based on job level. The attached summary provides the perquisites available by job level. Payment varies based on actual usage of the various perquisites offered.

Example of Short-Term and Long-Term Incentive Calculations
Responding Witness – Paula H. Pottinger, Ph.D.

Short-Term Incentive Award Example

Name	Base Salary	Target Incentive %	Total Target	From	To	# of Days	Performance Period Percent	Target Payout		E.ON U.S. Adjusted EBIT	Management Effectiveness
									Measure Weighting %	40%	60%
Employee Name	$ 125,000	25.0%	$ 31,250	1/1/2007	12/31/2007	365	100%	$ 31,250	Target Payout $	12,500.00	18,750.00
									Payout %	105.00%	100.0%
						365		$ 31,250	Earned Payout $	$ 13,125.00	$ 18,750.00
							Total Target	**$ 31,250**		**$ 31,875**	**Payout**

Long-Term Incentive Award Example - LG&E Energy Corp. Performance Unit Plan

2005 Grant $	$37,500	A

Payout Calculation Example		
Year	Sample Performance Payout %	
2005	100.0%	Current Measure for Performance Units is E.ON U.S. Value-Added
2006	104.9%	
2007	108.3%	
Average Performance Payout % 2005 - 2007	104.40%	B

Sample Payout (March 2008)	$39,150	A X B

E.ON Short-Term Incentive System for Top Executive Group
Responding Witness – Paula H. Pottinger, Ph.D.

E.ON Short-Term Incentive System for the Top Executive Group (TEG)

Contents

1. Preliminary Remarks
2. E.ON Compensation Philosophy for the Top Executive Group
3. Overview
4. The New Short-Term Incentive Plan: Details and Application
5. Annex / Forms

1. Preliminary Remarks

E.ON is one of the largest and most successful energy companies.

Our overriding objective is to shift the focus from striving for size to striving for more efficiency in order to achieve continuous improvement and deliver the potential we have in the Group.

In this way, we want to rise to become the undisputed market leader in our industry and create value for our investors.

The goal that guides us in our efforts is to make E.ON the world's leading power and gas company.

The business contribution of the executives who belong to the Top Executive Group (TEG) is the key to our ability to achieve our strategic objectives. The new compensation philosophy for the Top Executive Group is designed to reward this contribution.

The new Short-Term Incentive (STI) System will ensure that the annual variable compensation (referred to as "bonus" below) of all the members of the Top Executive Group will in future be linked even more closely both to the performance of the E.ON Group and to the individual's performance.

2. E.ON Compensation Philosophy for the Top Executive Group

An up-to-date and consistent compensation philosophy helps to position a company as an employer of choice in an international environment. E.ON's compensation systems are based on a Group-wide compensation philosophy and its consistent implementation within the E.ON Group.

The Group-wide harmonization of the compensation systems for the Top Executive Group supports the guiding principles of "OneE.ON". A consistent structure (e.g. short-term and long-term incentives) of executive compensation systems as well as their link to consistent performance indicators guarantee that executives will make the best possible contribution to the implementation of our Group strategy.

3. Overview

Eligibility

The new E.ON STI plan will apply to all members of the Top Executive Group (TEG) from January 1, 2005. Where executives have differing legal or contractual bonus agreements, these will be brought into line with the new bonus system.

Line Manager

The line manager is the executive to whom an individual reports at the next higher hierarchy level or, in the case of board functions, the Chairman of the respective Supervisory Board.

Executive

The term "executive" means the individual eligible to receive a bonus.

Bonus

The term "bonus" means the annual variable compensation that may be paid out under E.ON's Short-Term Incentive Plan (STI).

Target-setting agreement

The target-setting agreement will be used as a key management tool in the framework of the new bonus system. The target-setting agreement is a written agreement in which both the business performance targets that are relevant for a given executive and the personal performance targets agreed between the executive and his or her line manager are recorded for a given financial year (defined as running from 1. Jan – 31. Dec).

The level of the bonus will vary with the degree to which these targets are achieved.

Target bonus

The term "target bonus" means the amount of compensation for a given financial year that will be paid out if all the targets are fully achieved. The amount of the target bonus will be determined in advance.

Targets: Business performance

The planned business performance will be documented in the target-setting agreement and used as one element for the determination of the bonus.

The percentage split between business and personal targets will depend on where the employing company is positioned within the organization (Corporate Center, Market Unit, Business Unit) and on whether, or not, an executive holds a board position.

The business performance targets (usually "adjusted EBIT") are set at the beginning of a financial year in cooperation with the Corporate Controlling Department and the relevant controlling / finance departments in the Market Units.

Targets: Personal targets

The target-setting agreements will also specify personal targets as a criterion to determine the executive's bonus. A minimum of 3 and a maximum of 5 personal targets should be agreed between the executive and his or her line manager and recorded in the target-setting agreement.

Quality of wording of personal targets

The wording of the personal targets must be precise. The targets defined must be ambitious, and the criteria applied to measure the degree of target achievement must be comprehensible. Depending on their importance, personal targets may be weighted differently.

Degree of target achievement: business performance targets

Business performance is usually measured in terms of the company's "adjusted EBIT". Adjusted EBIT will be measured as a percentage of actual versus previously budgeted adjusted EBIT. As a general rule, the degree of target achievement can vary between

- a minimum of 0 % (if 70 % or less of the budgeted adjusted EBIT is achieved) and
- a maximum of 200 % (if 130 % or more of the budgeted adjusted EBIT is achieved).

Degree of target achievement: personal performance targets

There will be five grades to rate the level of personal target achievement:
from "target not achieved" (0 %) up to "target greatly exceeded" (200 %). The review, where appropriate, may also cover values between the specified percentages (e.g. 125 %).

Overall managerial performance

An executive's general managerial performance may, for many reasons, differ from the actual degree of target achievement and the line manager may want to appraise overall performance rather than performance against agreed objectives. Overall management performance may be better or worse than the performance calculated against actual target achievement. The proposed bonuses will be subject to approval by the Board of Management of E.ON AG. This will ensure a consistent application of the system across all Market Units.

Minimum / maximum bonus

Under the STI plan, there is no guaranteed minimum bonus payment. If overall an executive accomplishes less than 50 % (cut-off) of the agreed personal targets, there will be no bonus payment made irrespective of business target achievement.

The maximum payment that an executive can achieve is double (200%) of the target bonus.

Contractual agreements

The new bonus rules will not affect any contractually agreed minimum bonuses.

Performance review with executive

The line manager to whom an executive reports will be responsible for agreeing targets and assessing the degree of their achievement during a personal meeting with the executive. These meetings should take place at the end of each financial year.

Approval by the Board of Management of E.ON AG

The E.ON AG Board will review and approve the bonuses proposed for all executives in the Top Executive Group.

4. The New Short-Term Incentive Plan: Details and Application

The new E.ON STI is an additive plan. This means that performance is split into a number of individual target elements. Actual performance against these targets are then added together to calculate the final bonus achievement.

Financial targets - usually budgeted adjusted EBIT at Corporate Center, Market Unit and Business Unit level - as well as the executive's personal targets will be agreed in advance for one financial year.

Target categories

The business performance targets and personal targets will be weighted in accordance with the matrix below. The matrix below shows the percentage split between personal targets and business performance targets in the overall target bonus.

The weighting of the various parts of the bonus will depend on where the employing company is positioned within the organization (Corporate Center, Market Unit, Business Unit) and on whether, or not, an executive has a board role.

	Group (Adj. EBIT) +	Market Unit (Adj. EBIT) +	Business Unit (Adj. EBIT) +	Personal Targets
CC Executive	40 %			60 %
MU Board	20 %	40 %		40 %
Dual Role *	20 %	20 %	20 %	40 %
MU Executive	20 %	20 %		60 %
BU Board	10 %	10 %	30 %	50 %
BU Executive	10 %	10 %	20 %	60 %
Dual BU Role **	10 %	25 %***	25 %****	40 %

* Functions with board responsibility and business unit responsibility

** Functions with board responsibility at business unit level and operative responsibility at the level below

*** Counts as business unit level in this case

**** Counts as level below business unit in this case

Business performance: Adjusted EBIT

E.ON's key internal earnings figure is adjusted EBIT (Earnings Before Interest and Taxes), which is used as an indicator of the sustainable profitability of a business. The adjusted EBIT is not influenced by any fiscal or financial factors. Certain one-off or rare effects are also eliminated from the adjusted EBIT. This includes in particular book gains and restructuring expenses. The adjusted EBIT therefore covers the company's sustainable performance from the current sales process as well as the sustainable income from investments. For more information, please consult the E.ON *Planning and Controlling Handbook*.

The adjusted EBIT targets are identical to the budget targets set as a result of the annual planning process. These targets are adjusted in the event that the capital employed differs from the budget targets and if there are major unplanned portfolio changes.

Personal targets

An executive's personal targets will invariably be derived from Group, Market Unit and Business Unit targets, and at the same time, they must be related to the executive's functional area and scope of responsibilities.

Both strategic and operational targets can be specified in the target-setting agreement. Personal targets may be linked to key business performance figures or they may be aimed at personal managerial objectives. It is also possible to define team targets, which may be appropriate when there are projects to modify or improve joint processes and operations.

A minimum of 3 and a maximum of 5 personal targets should be agreed between the executive and his or her line manager in the target-setting process and recorded in the target-setting agreement. Depending on their importance, personal targets can be weighted differently.

At least one personal target may be derived from the "OneE.ON Performance Measurement" work. Targets can be chosen from the following categories:

- Customer satisfaction
- Brand value
- Commitment of employees and attractiveness as an employer
- Safety
- Sustainable development
- Security of supply

In addition, it is recommended that one of the personal targets, for executives with corporate roles (Corporate Center and Market Unit levels), should be a budget target.

Quality of Personal Targets

Targets must meet high standards in terms of the way they are worded because:

- the clearer the target, the stronger its effect as a management tool
- the clearer and the more comprehensible the criteria applied to assess the target achievement, the simpler the appraisal of the target achievement and the greater the acceptance of the process and its results

It is particularly important to agree on suitable measures for the assessment of the target achievement because the degree of target achievement ultimately determines the amount of the bonus paid out to an executive.

When describing a target, attention should be paid to the following points:

- Completeness: target content (what?), scope of the target (how much?) and time horizon (by when?)
- Consistency
- Result orientation: "The target will be achieved if ...."
- Where the achievement of targets can be measured quantitatively: it may be necessary to define target corridors (from .... to)
- Agreement on suitable assessment criteria to determine the degree of target achievement; it must also be possible to rate the degree of target achievement of executives who surpass their targets.

The availability of the data needed to determine the degree of target achievement must be guaranteed. The method to be used to measure the degree of target achievement must be agreed at the time when the target-setting agreement is concluded. Targets whose measurement or appraisal involves uncertainties should be avoided.

After the conclusion of a target-setting agreement with an executive's line manager, the agreement must be transmitted to the E.ON Corporate Executive HR Department in E.ON's Corporate Center via the relevant department in the Market Unit with responsibility for executives.

Examples of personal targets

- Execution of the "best-practice" program through implementation of the project "xy" by .... (month / year)
- Presentation of a retail strategy capable of being implemented with the objective of sustainably increasing the number of customers by .... % by .... (month / year)
- Completion of the integration of new company X into the controlling system of the E.ON Group by ....
- Identifying and implementing measures designed to reduce the budgeted administrative expenses by X % by .... (month / year) relative to the actual budget for the year ....

Target adjustments in the course of a year

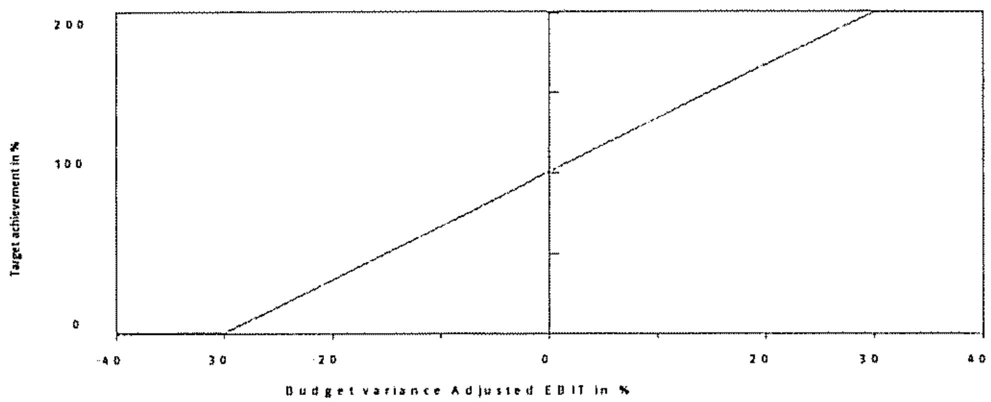
It is recognised that personal targets may change in the course of a year (additions, modifications, deletions). Such changes must be agreed with the line manager. The Corporate Executive HR Department in E.ON's Corporate Center must be informed about such changes at the time when they are agreed.

Measurement / Appraisal of target achievement: business performance targets

The degree of achievement of the business performance target is usually rated as follows in terms of the adjusted EBIT:

Degree of target achievement: Actual relative to budgeted adjusted EBIT	**%age of variable target bonus achieved based on corporate performance**
70%	0%
85%	50%
100%	100%
115%	150%
130%	200%

The diagram below shows the linear bonus payout range which is used for each element of the STI Plan:



A target achievement of 100 % means that the business target has been fully achieved based upon the adjusted EBIT budgeted for a given financial year and relative to a agreed amount of capital employed.

For target achievement levels ranging between 70 and 130 %, the target bonus achieved will be determined on a straight line basis (linear interpolation).

The overall target achievement based on the business performance is calculated by adding all weighted target achievements (Group, Market Unit and Business Unit levels; see matrix on page 6).
The degree of target achievement at Market Unit or Business Unit levels will be agreed between E.ON's Corporate Center (Corporate Controlling, Corporate Executive HR) and the relevant departments (Controlling, Executive HR) in the Market Units.

Evaluation of target achievement: personal targets

The evaluation of personal target achievement will be broken down into five categories:

Degree of target achievement	%age of variable target bonus achieved based on personal performance
Target not achieved	0%
Target partially achieved (50%)	50%
Target achieved (100%)	100%
Target exceeded by a wide margin (150%)	150%
Target greatly exceeded (200%)	200%

A target achievement of 100 % means that the target has been fully achieved. Any variation from this level must be explained and documented. An executive's performance will be evaluated for each personal target. The degree of achievement of all personal targets will be calculated by adding up the (possibly weighted) degrees of achievement of each specific target.

It is not acceptable to compensate for a missed target by giving excessively positive achievement levels for other targets.

The performance achievement may also cover values between the specified percentages (e.g. 125 %).

Overall target achievement

An executive's overall target achievement will be calculated by adding both corporate performance achievement and personal performance achievement. The results documented will be rounded to two decimal places in accordance with commercial custom.

Example illustrating the calculation of the Short-Term Incentive

The ratio of business targets to personal targets will be fixed in advance, depending on where a given position is located within the organizational structure (Corporate Center, Market Unit, Business Unit) and on the level of responsibility (eg board responsibility, see matrix on page 6).

Depending on their relative importance, the percentage weight of personal targets may either be identical or different.

This can be illustrated by means of the following example:

In the case of a Market Unit executive, for instance, the predetermined weighting between corporate targets and personal targets would be as follows in accordance with the matrix on page 6:

20% : 20% : 60%
(adj. Group EBIT : adj. Market Unit EBIT : Personal)

The 60% share of the agreed personal targets would be divided up between the number of targets (from minimum of three to a maximum of five), with the weighting being either different or identical for each target. In this example, there are three personal targets, which are weighted 0.5 : 0.25 : 0.25.

The degree of achievement (between 0 and 200 %) of each of the corporate and personal targets will be determined and weighted in accordance with the predetermined %age weights.

In this example, the targets have been accomplished as follows:

Achievement of the corporate performance target for the E.ON Group:
7.5 % above budgeted adjusted EBIT ➡ Target achievement: **125 %**

Achievement of the corporate performance target for the Market Unit:
10 % above budgeted adjusted EBIT ➡ Target achievement: **133.3%**

Achievement of personal targets:

Target 1	120 %	(weighted at 0.5)
Target 2	80 %	(weighted at 0.25)
Target 3	150 %	(weighted at 0.25)

The sum total for the personal targets amounts to:
(120% x 0.5)+ (80% x 0.25) + (150 x 0.25) = 60 % + 20% + 37.5% = **117.5%**

The executive's overall target achievement can now be calculated as follows:

(adj. Group EBIT) x 20% + (adj. Market Unit EBIT) x 20% + (Personal) x 60%

= (125%) x 20% + (133.3%) x 20% + (117.5%) x 60%
= 25% + 26.7% + 70.5%
= **122.2%**

5. Annex / Forms

Bonus and target-setting process

The conclusion of the target-setting agreement is the start of the annual bonus process and the final calculation of the target achievement completes the process.

Timetable

December	Preliminary meeting between the executive and his or her line manager to define targets for the following fiscal year (Y2)
January	For the personal targets: The executive's target achievement will be determined and his or her performance will be appraised by the line manager for the previous fiscal year (Y1), based on the executive's self-assessment
February	Personal meetings between executives and their line managers to discuss • the target achievement in terms of the *corporate performance* and the *executive's personal performance* during the past fiscal year (Y1) • the finalization of the *personal* targets agreed for the current year (Y2) *Corporate performance* targets will be defined for the current year (Y2) at Group, Market Unit and Business Unit levels and approved by the Board of Management of E.ON AG. The targets will be agreed in advance among Corporate Controlling, Corporate Executive HR and the relevant departments of the Market Units. Results of the Top Executive Group's target-setting and target achievement appraisal meetings will be transmitted to the HR department in charge of an executive's contract or the Executive HR unit of the Market Unit concerned and to Corporate Executive HR in E.ON's Corporate Center.
March	The proposed bonuses will be examined and approved by the Board of Management of E.ON AG.
April	As a rule, bonuses will be paid out after the Annual Shareholders Meeting of E.ON AG.

LG&E Energy Corp. Long-Term Performance Unit Plan
Responding Witness – Paula H. Pottinger, Ph.D.

LG&E ENERGY CORP. LONG-TERM PERFORMANCE UNIT PLAN

Effective January 1, 2003

ARTICLE 1. ESTABLISHMENT, PURPOSE, AND DURATION

1.1. Establishment of the Plan.

LG&E Energy Corp, (hereinafter referred to as the "Company") establishes as of the date set forth above the "LG&E Energy Corp. Long-Term Performance Unit Plan" (hereinafter referred to as the "Plan"), which permits the grant of Performance Units, as hereinafter defined, to employees of LG&E Energy Corp. and its Subsidiaries. The Plan was approved by the Board of Directors of the Company in a consent resolution dated April 25, 2003.

1.2. Purpose of the Plan.

The purpose of the Plan is to promote the success of the Company and its Subsidiaries by providing incentives to Key Employees that will link their personal interests to the long-term financial success of the Company and its Subsidiaries and to growth in Parent shareholder value. The Plan is designed to provide flexibility to the Company and its Subsidiaries in their ability to motivate, attract, and retain the services of Key Employees upon whose judgment, interest, and special effort the successful conduct of their operations is largely dependent. Grants under the Plan may be made in conjunction with grants of phantom options under the E.ON Phantom Option Plan in the case of certain Key Employees.

1.3. Duration of the Plan.

The Plan is effective as of January 1, 2003. The Plan shall remain in effect, subject to the right of the Board of Directors to terminate the Plan at any time pursuant to Article 9 herein.

ARTICLE 2. DEFINITIONS AND CONSTRUCTION

2.1. Definitions.

Whenever used in the Plan, the following terms shall have the meanings set forth below and, when the meaning is intended, the initial letter of the word is capitalized:

(a) "Award" means a grant under this Plan of Performance Units.

(b) "Beneficial Ownership" shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Exchange Act.

(c) "Board" or "Board of Directors" means the Board of Directors of the Company.

(d) "Cause" shall mean the occurrence of any one of the following:

   (i) The willful and continued failure by a Participant to substantially perform his/her duties (other than any such failure resulting from the Participant's disability), after a written demand for substantial performance is delivered to the Participant that specifically identifies the manner in which the Company or any of its Subsidiaries, as the case may be, believes that the Participant has not substantially performed his/her duties, and the Participant has failed to remedy the situation within ten (10) business days of receiving such notice; or

   (ii) the Participant's conviction for committing a felony in connection with the employment relationship; or

   (iii) the willful engaging by the Participant in gross misconduct materially and demonstrably injurious to the Company or any of its Subsidiaries. However, no act, or failure to act, on the Participant's part shall be considered "willful" unless done, or omitted to be done, by the Participant not in good faith and without reasonable belief that his/her action or omission was in the best interest of the Company or any of its Subsidiaries.

(e) "Change in Control" shall be deemed to have occurred if the conditions set forth in any one of the following paragraphs shall have been satisfied:

   (i) Parent is notified by a third party that it has acquired 25 percent or more of the voting rights of Parent in accordance with § 21 of the German Securities Trading Act (WpHG), or

   (ii) a third party on its own or together with voting rights attributable to him in accordance with § 22 German Securities Trading Act (WpHG) has acquired a share in voting rights which, at Parent's Annual Shareholders' Meeting, would represent or which, at Parent's last Annual Shareholders' Meeting, would have represented the majority of the voting rights present at such a Meeting, or

   (iii) an affiliation agreement is concluded with Parent as controlled company in accordance with §§ 291 ff. of the German Stock

Corporation Act (AktG), or

(iv) Parent is being integrated in accordance with §§ 319 ff. of the German Stock Corporation Act (AktG), or

(v) Parent changes its legal status in accordance with §§ 190 ff. of the German Conversion Law (UmwG), or

(vi) Parent is being merged with another legal entity, provided that the enterprise value of such legal entity is more than 20 percent of the enterprise value of Parent at the time of adopting the resolution by Parent. The methods of valuation acknowledged by the professional association of qualified auditors (Stellungnahme des Hauptfachausschusses des Instituts der Wirtschaftsprüfer HF 2/1983 = Grundsätze zur Durchführung von Untemehmensbewertungen sowie die neueren Verlautbarungen des Berufsstandes) shall be used to determine the value of both entities, to the extent that both enterprise values will be determined according to said methods in connection with the merger. Otherwise, the market capitalization of both legal entities at the time the resolution is adopted by Parent will be deemed as their respective enterprise values. If a market capitalization cannot be determined, the enterprise values agreed upon by both legal entities will be deemed as their respective values.

(vii) Company ceases to be an affiliated company of Parent as defined in § 15 of the German Stock Corporation Act or where the following apply:

(a) A complete liquidation or dissolution of the Company unless, the Parent continues to own directly or indirectly all or substantially all of the Company's assets;

(b) An agreement for the sale or other disposition of all or substantially all of the assets of the Company to any person or entity (other than a subsidiary of the Parent);

(c) A merger or other combination involving the Company as a result of which Parent ceases to beneficially own more that 50% of the outstanding Voting Stock, of the successor to the Company, unless the Parent or its subsidiary continues to own directly or indirectly all or substantially all of the Company's assets; or

(d) Any person or entity acquires Beneficial Ownership of a greater percentage of the Voting Stock of the Company than the percentage or such Voting Stock then held, directly or indirectly by Parent.

(f) "Committee" means the Senior Vice President, Group Corporate Officer Resources - of the Parent and any other person, if any, designated by the Chairman and Chief Executive Officer of the Parent to administer the Plan pursuant to Article 3 herein.

(g) "Company" means LG&E Energy Corp., a Kentucky corporation, or any successor thereto as provided in Article 11 herein.

(h) "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time.

(i) "Key Employee" means (i) an employee of the Company or any of its Subsidiaries, including an employee who is an officer or a director of the Company or any of its Subsidiaries, who, in the opinion of the Committee, can contribute significantly to the growth and profitability of the Company and its Subsidiaries, (ii) may include employees who are members of the Board who are employees, or (iii) any other employee, identified by the Committee, in special situations involving extraordinary performance, promotion, retention, or recruitment. The granting of an Award under this Plan shall be deemed a determination by the Committee that such employee is a Key Employee, but shall not create a right to remain a Key Employee.

(j) "Parent" means E.ON AG, an anktiengesellschaft formed under the Federal Republic of Germany, or any successor thereto as provided in Article 11 herein.

(k) "Participant" means a Key Employee who has been granted an Award under the Plan.

(l) "Performance Unit" means an Award, designated as a performance unit, granted to a Participant pursuant to Article 5 herein.

(m) "Person" shall have the meaning ascribed to such term in Section 3(a) (9) of the Exchange Act and used in Sections 13(d) and 14(d) thereof, including a "group" as defined in Section 13(d) thereof.

(n) "Plan" means this LG&E Energy Corp. Long-Term Performance Unit Plan, as herein described and as hereafter from time to time amended.

(o) "Subsidiary" shall mean any corporation of which more than 50% (by number of votes) of the Voting Stock at the time outstanding is owned, directly or indirectly, by the Company.

(p) "Voting Stock" shall mean securities of any class or classes of stock of a corporation, the holders of which are ordinarily, in the absence of contingencies, entitled to elect a majority of the corporate directors.

2.2. Gender and Number.

Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine, the plural shall include the singular, and the singular shall include the plural.

2.3. Severability.

In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

ARTICLE 3. ADMINISTRATION

3.1. The Committee.

The Plan shall be administered by the Committee as permitted by law and Article 3.5.

3.2. Authority of the Committee.

Subject to the provisions of the Plan, the Committee shall have full power to construe and interpret the Plan; to establish, amend or waive rules and regulations for its administration; to accelerate the end of a performance period or the termination of any award agreement; and (subject to the provisions of Article 9 herein) to amend the terms and conditions of any outstanding Award to the extent such terms and conditions are within the discretion of the Committee as provided in the Plan. The Committee shall not have authority to resolve disputed claims under the Plan.

3.3. Selection of Participants.

The Committee shall have the authority to grant Awards under the Plan, from time to time, to such Key Employees (including officers and directors who are employees) as may be selected by it. The Committee shall select Participants from among those whom they have identified as being Key Employees.

3.4. Decisions and Appeals.

All determinations and decisions made by Committee pursuant to the provisions of the Plan may be reviewed by the Chairman and Chief Executive Officer of the Parent, upon the written request of either the Committee or a Participant. Any determination made by the

Chairman and Chief Executive Officer of the Parent, pursuant to this section shall be final, conclusive and binding on all persons, including the Company and its Subsidiaries, its shareholders, employees, and Participants and their estates and beneficiaries, and such determinations and decisions shall not be subject to review.

3.5. Delegation of Certain Responsibilities.

The Committee may delegate to an appropriate party any of its responsibilities under the Plan.

3.6. Procedures of the Committee.

To the extent the Committee is comprised of more than one member, all determinations of the Committee or any delegates shall be made by not less than a majority of members present at any meeting (in person or otherwise) at which a quorum is present. A majority of the entire Committee or the number of delegates at a given time shall constitute a quorum for the transaction of business. Any action required or permitted to be taken at a meeting of the Committee or the delegates may be taken without a meeting if a unanimous written consent, which sets forth the action, is signed by each member of the Committee and filed with the minutes for proceedings of the Committee or delegates.

3.7. Award Agreements.

Each Award under the Plan shall be evidenced by an award agreement which shall be signed by an authorized officer of the Company and by the Participant, and shall contain such terms and conditions as may be approved by the Committee. Such terms and conditions need not be the same in all cases.

ARTICLE 4. ELIGIBILITY AND PARTICIPATION

4.1. Eligibility.

Persons eligible to participate in this Plan include all employees of the Company and its Subsidiaries who, in the opinion of the Committee, are Key Employees.

4.2. Actual Participation.

Subject to the provisions of the Plan, the Committee may from time to time select those Key Employees to whom Awards shall be granted and determine the nature and amount of each Award. No employee shall have any right to be granted an Award under this Plan even if previously granted an Award.

ARTICLE 5. PERFORMANCE UNITS

5.1. Grant of Performance Units.

Subject to the terms and provisions of the Plan, Performance Units may be granted to Participants at any time and from time to time as shall be determined by the Committee or any delegate who shall have complete discretion in determining the number of Performance Units granted to each Key Employee.

5.2. Value of Performance Units .

The Committee shall set performance goals over certain periods to be determined in advance by the Committee ("Performance Periods"). The initial value for each Performance Unit shall be one dollar. With regard to each grant of Performance Units, the Committee in consultation with the Senior Vice President Controlling of the Parent shall set the performance goals that will be used to determine the extent to which the Participant receives a payment of the value of the Performance Units awarded for such Performance Period. These goals will be based on the attainment, by the Parent, Company, or its Subsidiaries, of certain objective performance measures. With respect to each such performance measure utilized during a Performance Period, the Committee shall assign percentages to various levels of performance which shall be applied to determine the extent to which the Participant shall receive a payout of the value of Performance Units.

5.3. Payment of Performance Units.

After a Performance Period has ended, the holder of a Performance Unit shall be entitled to receive the value thereof as determined by the Committee. The Committee shall make this determination by first determining the extent to which the performance goals set pursuant to Section 5.2 have been met. It will then determine the applicable percentage (which may be greater or lesser than 100%) to be applied to, and will apply such percentage to, the value of Performance Units to determine the payout to be received by the Participant. In addition, with respect to Performance Units granted to any Key Employee, no payout shall be made hereunder except upon written certification by the Committee that the applicable performance goal or goals have been satisfied to a particular extent.

5.4. Discretion to Adjust Awards.

The Committee shall have the authority to modify, amend, or adjust the terms and conditions of any Performance Unit award, at any time or from time to time, including but not limited to the performance goals.

5.5. Form and Timing of Payment.

The payment described in Section 5.3 herein shall be made in a cash lump sum as soon as administratively practical upon the determination by the Committee provided for in Section 5.3, unless the Participant has previously elected to defer such payment in a manner prescribed by the Committee. If any payment is permitted by the Committee to be made on a deferred basis, the Committee may provide for earnings to be credited on such amount in a manner they determine.

5.6. Termination of Employment Due to Death, Disability, or Retirement.

In the case of death, disability, or retirement (each of disability and retirement as defined under the established rules of the Company or any of its Subsidiaries, as the case may be), the holder of a Performance Unit shall receive a prorated payment based on the Participant's number of full months of service during the Performance Period, further adjusted based on the achievement of the performance goals during the entire Performance Period, as computed by the Committee. Payment shall be made at the time payments are made to Participants who did not terminate service during the Performance Period.

5.7. Termination of Employment for Other Reasons.

In the event that a Participant terminates employment with the Company or any of its Subsidiaries for any reason other than death, disability, or retirement, prior to the end of the Performance Period all Performance Units shall be forfeited; provided however, in the case of any termination not for Cause, the Committee in its sole discretion may waive the automatic forfeiture provisions and make a prorated payment to the holder of a Performance Unit. Payment made pursuant to this Section shall be made at the time payments are made to Participants who did not terminate service during the Performance Period. In the event of a Participant's termination of employment pursuant to this Section after completion of the respective Performance Period of a Performance Unit, but prior to payment pursuant to Section 5.5, the Participant shall be entitled to payment without proration.

5.8. Nontransferability.

No Performance Units granted under the Plan may be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution until the termination of the applicable performance period. All rights with respect to Performance Units granted to a Participant under the Plan shall be exercisable during his lifetime only by such Participant.

ARTICLE 6. BENEFICIARY DESIGNATION

Each Participant under the Plan may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively and who may include a trustee under a will or living trust) to whom any benefit under the Plan is to be paid in case of his death before he receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Committee, and will be effective only when filed by the Participant in writing with the Committee during his lifetime. In the absence of any such designation or if all designated beneficiaries predecease the Participant, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

ARTICLE 7. RIGHTS OF EMPLOYEES

7.1. Employment.

Nothing in the Plan shall interfere with or limit in any way the right of the Company or any of its Subsidiaries to terminate any Participant's employment at any time, nor confer upon any Participant any right to continue in the employ of the Company or any of its Subsidiaries.

7.2. Participation.

No employee shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant.

7.3. No Implied Rights; Rights on Termination of Service.

Neither the establishment of the Plan nor any amendment thereof shall be construed as giving any Participant, beneficiary, or any other person any legal or equitable right unless such right shall be specifically provided for in the Plan or conferred by specific action of the Committee in accordance with the terms and provisions of the Plan. Except as expressly provided in this Plan, neither the Company nor any of its Subsidiaries shall be required or be liable to make any payment under the Plan.

7.4. No Right to Company Assets.

Neither the Participant nor any other person shall acquire, by reason of the Plan, any right in or title to any assets, funds or property of the Parent, Company or any of its Subsidiaries whatsoever including, without limiting the generality of the foregoing, any specific funds, assets, or other property which the Parent, Company or any of its Subsidiaries, in its sole discretion, may set aside in anticipation of a liability hereunder. Any benefits which become payable hereunder shall be paid from the general assets of the Parent, Company or the applicable subsidiary. The Participant shall have only a contractual right to the amounts, if any, payable hereunder unsecured by any asset of the Company or any of its Subsidiaries. Nothing contained in the Plan constitutes a guarantee by the Company or any of its Subsidiaries that the assets of the Company or the applicable subsidiary shall be sufficient to pay any benefit to any person.

ARTICLE 8. CHANGE IN CONTROL

Notwithstanding any other provisions of the Plan, in the event of a Change in Control, all Performance Unit awards granted under this Plan shall be immediately paid out in cash. The amount of the payout shall be based on the higher of:

(i) the extent, as determined by the Committee, to which performance goals, established for the Performance Period then in progress have been met up through and including the effective date of the Change in Control or

(ii) 100% of the value on the date of grant of the Performance Units.

ARTICLE 9. AMENDMENT, MODIFICATION, AND TERMINATION

9.1. Amendment, Modification, and Termination.

At any time and from time to time, the Board, upon recommendation by the Committee, may terminate, amend, or modify the Plan.

9.2. Awards Previously Granted.

No termination, amendment, or modification of the Plan shall in any manner adversely affect any Award theretofore granted under the Plan, without the written consent of the Participant.

ARTICLE 10. TAX WITHHOLDING

The Company and any of its Subsidiaries shall have the power and the right to deduct or withhold, or require a Participant to remit to the Company or any of its Subsidiaries, an amount sufficient to satisfy taxes (including the Participant's FICA obligation) required by law to be withheld with respect to any grant, exercise, or payment made under or as a result of this Plan.

ARTICLE 11. PARENT AND SUCCESSORS

All obligations of the Company under the Plan, with respect to Awards granted hereunder, shall be binding on the Parent and any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation or otherwise, of all or substantially all of the business and/or assets of the Company.

ARTICLE 12. REQUIREMENTS AND GOVERNING LAW

12.1. Requirements of Law.

The granting of Awards under this Plan shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

12.2. <u>Governing Law</u>.

The Plan, and all agreements hereunder, shall be construed in accordance with and governed by the laws of the Commonwealth of Kentucky.

Perquisites
Responding Witness – Paula H. Pottinger, Ph.D.

Officer Perquisites

Description	CEO	EVP	SVP	VP	VP - Senior Manager
Automobile	Y	Y	Y	Y	N
Country Club	Y	N	N	N	N
Financial Planning and Tax Preparation	Y	Y	Y	Y	N
Life Insurance - Group Term (1)	Y	Y	Y	Y	Y
Life Insurance - Supplemental Executive	Y	Y	Y	Y	N
Luncheon Club	Y	Y	Y	Y	N
Nonqualified Savings Plan	Y	Y	Y	Y	Y
Spousal Air Travel	Y	Y	Y	Y	N
Supplemental Executive Retirement Plan (SERP)	Y	Y	Y	Y	N
Vacation Sellback (2)	Y	Y	Y	Y	Y
Wellfit and Choose Well Health Incentives (1)	Y	Y	Y	Y	Y

(1) Officers are eligible for the same level of benefit as non-officer employees.

(2) Officers may choose to receive pay in lieu of 1 week of vacation. This policy is available to non-officer employees as well.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 29

Responding Witness: Chris Hermann / Shannon L. Charnas / Robert M. Conroy

Q-29. Refer to KU's response to Staffs Second Request, Item 108(a). The level of conservation advertising expensed by KU over the previous 5 years fluctuates from a high of $536,623 in 2007 to a low of $95,783 in 2004.

a. Explain how KU determines the amount of conservation advertising it will incur in any given year.

b. State the amount of conservation advertising that was originally included in KU's monthly 2008 operating budgets for Kentucky jurisdictional operations and the actual amount of monthly Kentucky jurisdictional conservation advertising expensed by KU.

A-29. a. The method for determining the level of conservation advertising incurred annually is not formulaic. The Company considers numerous factors, including the recommendations of third-party agencies, availability of funds, prioritization of important topics, surveys or other customer feedback, relevance of other related announcements, and other externalities. This is a dynamic process that changes throughout the year as other energy-efficiency-related topics, news coverage, announcements, or initiatives take place locally or nationally.

b. Items included in Account 909 are not limited to conservation advertising. The annual operating budgets are consistent with the accounting practices and are not developed in a way that permits distinction of conservation advertising.

Actual monthly advertising expenses charged to Account 909 for 2008 is as follows:

	KU Total Company	Allocator	KU Jurisdictionalized
Jan-08	$ (7,378.55)	0.94412	$ (6,966.24)
Feb-08	26,168.06	0.94412	24,705.79
Mar-08	(7,670.02)	0.94412	(7,241.42)
Apr-08	15.09	0.94412	14.25
May-08	38,549.98	0.94412	36,395.81
Jun-08	(16,055.46)	0.94412	(15,158.28)
Jul-08	2,831.38	0.94412	2,673.16
Aug-08	20,605.00	0.94412	19,453.59
Total	$ 57,065.48		$ 53,876.66

Approximately 65% of the total above is for expenses related to encouraging environmental protection and conserving electric energy. The $6,966.24 credit in January 2008, is due to the reversal of an accrual from December 2007, of which the invoices were actually paid in February 2008. The $7,241.42 credit in March 2008 is due to reclassifications of customer newsletter expenses for direct mailings incurred in February 2008, whch were appropriately reclassified to Account 930.1. The $15,158.28 credit in June 2008, is due to reclassifications of customer newsletter expenses for direct mailings incurred in May 2008, that were appropriately reclassified to Account 930.1. All amounts noted above are jurisdictional amounts.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 30

Responding Witness: Robert M. Conroy

Q-30. Refer to KU's response to Staffs Second Request, Item 112 and Volume 4 of 4 of KU's response to Staffs First Data Request, Item 57(b). At Item 112, KU states that actual publication costs from its previous rate application were $537,784. At Item 57(b), KU estimates that publication costs for the current case will be $828,000. Explain why the publication costs for this case are estimated to be 54 percent higher than the publication costs of the previous case.

A-30. The estimated publication costs included in the initial response to Staff's First Data Request, Item 57 were based on Kentucky Press Association estimates for publication of the required notices in this proceeding. As reported in KU's monthly update to Item 57 filed on September 26, 2008, the actual publication costs to-date in this case are $861,963.40. As directed in Item 57, KU provided copies of the invoices to support the actual publication costs.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 31

Responding Witness: Valerie L. Scott

Q-31. Refer to KU's response to Staffs Second Request, Item 109. Provide the amount of revenues related to KU Schedule 10 expenses realized by KU since the end of the test year through the most recent month available.

A-31. The amount of revenue related to MISO Schedule 10 expenses realized by KU from the end of the test year through August 2008 is $1,310,387 ($327,597 per month as ordered in Case No. 2003-00266 and corrected in Case No. 2005-00471).

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 32

Responding Witness: Shannon L. Charnas

Q-32. Refer to KU's response to Staffs Second Request, Items 113(a) and (c) and Volume 4 of 5 of KU's application at Rives Testimony, Exhibit 1, Schedule Reference 1.29. At Item 113(a), KU states that the test year IT contract expense was $2,051,795. At Item 113(c), KU states that the annual expense would have been $3,149,518, an increase of $1,097,532 or 54 percent, had prepayments been properly accounted for during the test year. To correct the accounting error, an adjustment was made at Schedule Reference 1.29 increasing test year expenses for Kentucky's jurisdictional portion in the amount of $978,329.

a. Explain how the change in accounting for the IT contracts resulted in a 54 percent increase to the annual expense.

b. Does KU's proposed adjustment result in more than 12 months of IT contract expense being accounted for in the *pro forma*? Explain.

A-32. a. The expense that should have been included in the test year was $3,149,518. The change in accounting for the IT contracts was to remove expenses from the test year that properly related to a future year and record the amounts paid related to a future year as a prepaid expense. Expenses that properly related to the test year were recorded as expenses in the year prior to the test year resulting in an understatement of expenses in the test year, thus, the *pro forma* adjustment in Reference Schedule 1.29 was made. There is not a 54% increase in the cost of IT maintenance contracts, but rather a reallocation of the cost to the year to which the costs properly apply.

b. No, as explained in part (a) above, the proposed adjustment correctly reflects KU's expense related to IT contracts for the 12 months ended April 30, 2008.

KENTUCKY UTILITIES COMPANY

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CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 33

Responding Witness: Shannon L. Charnas

Q-33. Refer to KU's response to Staffs Second Request, Item 114. Provide the monthly average per-gallon cost of fuel for September 2008. Also provide the monthly average per-gallon cost for October and November 2008 as those costs become available.

A-33. The September 2008 cost of fuel is not available at this time. The Company will provide the requested data through the monthly updates.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 34

Responding Witness: S. Bradford Rives

Q-34. Refer to KU's response to Staffs Second Request, Item 115.

a. Provide the date on which KU began to solicit proposals for the new credit facilities.

b. What is the specific date by which KU must make a decision as to the bank with whom it will enter into a credit agreement for the new credit facility?

A-34. a. KU has been having discussions with banks for several months about the possibility of providing letter of credit facilities. Since the response to PSC-2 Question No. 115, the Company has received three additional verbal quotes. KU is in the process of preparing documents for the bank that has provided the lowest bid. The pricing of the lowest bid (50 bps) is significantly lower than the amount included in the proposed adjustment (110 bps). In addition, the amount of bonds KU expects to enhance with letters of credit has changed slightly. The proposed adjustment was based on bonds totaling $200 million whereas the Company is now planning to enhance bonds totaling $194,847,405.

b. There is no deadline for KU to make the decision. However, the Company is expecting to complete all of the debt restructuring approved in Case No. 2008-00132 by the end of 2008.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 35

Responding Witness: Valerie L. Scott

Q-35. Refer to KU's response to Staff's Second Request, Items 116, 118, and 119, all of which pertain to the coal tax credit which is the subject of the adjustment at Volume 4 of 5 of KU's application at the Rives Testimony, Reference Schedules 1.33 and 1.41. The coal tax credit expires at the end of 2009, meaning the application for 2009 must be submitted by March 15, 2010, for use on either KU's 2009 state income tax return or its 2010 property tax return.

a. The years in which KU did not qualify for the credit were 2000, 2001, and 2002, the first three years the credit was available. Given that KU has qualified for the credit for five consecutive calendar years, explain why KU is concerned about the "contingent nature" of the credit.

b. In KU's response to Staffs Second Request, Item 31, Mr. Seelye refers to the "likelihood that the Companies will need to file rate cases in the near future (i.e., due to the need to recover the costs associated with Trimble County Unit 2)," With the anticipation of filing another rate case in conjunction with Trimble County Unit 2 going into service, which is scheduled for the summer of 2010, explain why KU is concerned about the expiration of the credit, the financial impact of which would not be realized until sometime in 2010.

A-35. a. KU has received the coal tax credit in the past five years, but each year is independent of the others. To receive the credit, KU must purchase enough Kentucky coal to exceed the 1999 base period. Since the credit is contingent on the amount of Kentucky coal purchases over the 1999 base period, it is not known if KU will receive the credit in one or both of the last two years of the statute. Also, if KU does exceed the base amount of purchases to receive a coal tax credit, the amount of the credit is not known. The coal tax credit has varied over the years from $0 to $2,500,000.

b. KU believes inclusion of this credit in the determination of future rates is not appropriate as the credit is not known or measureable. In addition, the statute is due to expire as explained in response to PSC-2 Question No. 116(d).

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 36

Responding Witness: Valerie L. Scott / Counsel

Q-36. Refer to KU's response to Staffs Second Request, Items 128 and 129.

a. Is KU aware that the Commission has previously approved "effective tax rate adjustments" where operating losses reported on consolidated tax returns by non-regulated entities are included in the calculation of recoverable income taxes for the regulated utilities that are a part of the consolidated returns? (See Commission's final Order of Case No. 2004-00103 dated February 28, 2005, pages 63- 66).

b. State KU's position on a consolidated tax adjustment in this case that follows the method established by previous Commission Order where a five-year average of non-regulated operating results (as provided in KU's response to Staffs Second Request at Items 128 and 129) would be included as a reduction to taxable income when calculating income taxes subject to rate recovery by KU.

A-36. a. The Company is aware that the Commission has previously approved "effective tax rate adjustments" where operating losses reported on consolidated tax returns by non-regulated entities are included in the calculation of recoverable income taxes for the regulated utilities. The Commission first addressed the issue in its January 31, 2002 Order in *In the Matter of: Adjustment of Gas Rates of the Union Light, Heat and Power Company.*[1] In that case, the applicant filed its tax returns as part of a consolidated group and calculated its *effective* Kentucky income tax rate at 3.03% and sought recovery at that rate rather than the statutory rate of 7%. The Commission allowed ULH&P to use the 3.03% effective rate, but stated that it had "some concerns about using this approach, especially since the effective rate changed from 5.15 to 3.03 percent between two tax years."[2] Because of that concern, the Commission stated that use of the effective rate would only be on a "trial basis." It then directed ULH&P to provide an

[1] Case No. 2001-00092
[2] Case No. 2001-00092, January 31, 2002 Order, p. 59.

analysis in its next rate case showing the effective Kentucky income tax rate for the years between 2000 and the tax year applicable to the next rate case.[3]

The Commission next addressed the issue in its February 28, 2005 Order in *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company*.[4] In that case, KAW sought recovery of its income tax expense based on the federal statutory rate of 35% of its taxable income. The AG retained Andrea Crane as an expert witness and she proposed a Consolidated Income Tax Adjustment ("CTA") based on the fact that KAW files its federal taxes as part of a consolidated group. The Commission held that the CTA should be approved and reduced KAW's federal income tax expense. However, the Order is clear that it did so *not* because it generally favors or agrees with the CTA concept. Instead, the lynchpin of the holding was that the PSC believed that KAW had committed in an earlier case that it would realize tax savings by virtue of being a member of a consolidated tax filing group.[5]

The Commission most recently addressed the issue in the rehearing phase of KU's 2003 rate case. In its March 31, 2006 Order on Rehearing in *In the Matter of: An Adjustment of the Rates, Terms and Conditions of Kentucky Utilities Company*,[6] the Commission rejected the use of a consolidated group driven "effective" tax rate in computing Kentucky income tax expense.[7]

In the case, KU argued that Kentucky's statutory rate should be used to calculate Kentucky income tax expense. The AG argued in favor of using an effective tax rate that resulted from KU's participation in a consolidated tax filing group. The AG cited the ULH&P and KAW cases discussed above as "precedent" for use of an effective tax rate. The Commission rejected the AG's argument. It stated that the ULH&P decision allowed use of an effective rate only on a trial basis until ULH&P's next rate case which had been filed[8] by the time the Commission addressed the issue in KU's case. In ULH&P's next rate case, ULH&P took the position that an effective tax rate should not be used because of the substantial variance in the rate from year to year. Instead, ULH&P argued that the statutory rate is "known, easily verifiable and not distorted by non-recurring items or apportionment adjustments attributable to other entities participating in the filing of a

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[3] *Id.*, p. 60.
[4] Case No. 2004-00103.
[5] Case No. 2004-00103, February 28, 2005 Order, p. 66 ("Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object now if we act upon their representation.")
[6] Case No. 2003-00434.
[7] The Commission reached a similar result in its Final Order issued March 31, 2006 in Case No. 2003-00433, In the Matter of, *An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*.
[8] Case No. 2005-00042.

consolidated tax return."[9] The Commission noted that the AG did not object to ULH&P's use of the statutory rate. As for the KAW case, the Commission again noted that Commission accepted the AG's federal consolidated tax adjustment based on a voluntary commitment, previously made by KAW in conjunction with its acquisition by RWE, that it would be able to file consolidated tax returns and achieve tax savings by doing so.[10]

The Commission reached the correct decision in the KU case in rejecting use of an effective tax rate. It held:

> By having to recognize tax losses and other tax credits related to these non-regulated activities to derive an effective Kentucky income tax rate could well be viewed as forcing the utility to use these non-regulated activities to subsidize the regulated utility operations.[11]

b. KU agrees with this determination of the Commission in Case No. 2003-00434.

The Commission's decision in the 2003 KU Rate Case is also consistent with the Commission's approval of the *Corporate Policies and Guidelines for LG&E and KU* in Case No. 97-300 and the Commission's approval of similar guidelines in connection with the establishment of LG&E's and KU's respective holding companies in Case Nos. 98-374 and 10296. Those guidelines contain a section on "stand alone" method for allocating the income tax liabilities for each entity. KU's Tax Allocation agreement also specifically states how tax payments and benefits will be handled. This agreement was provided to the Commission. The stand alone method is required by subsection four, third paragraph of the attached *Corporate Policies and Guidelines for Intercompany Transactions* and has been used by KU for many years.

KU is opposed to the use of the effective consolidated income tax rate in determining revenue rate requirements in this case. KU has not charged its customers for expenses incurred at its affiliated companies and has no plans to do so in the future. Because KU's customers have not paid for the losses of affiliated companies, or assumed any of the risks associated with the non-regulated companies, the customers should not bear the risk or receive the benefits of affiliates' taxable income or losses. As the Commission correctly stated in KU's last rate case, "By having to recognize tax losses and other tax credits related to these non-regulated activities to derive an effective Kentucky

[9] Case No 2003-00434, March 31, 2006 Order, p. 6. (quoting Case No 2005-00042, *An Adjustment of the Gas Rates of the Union Light Heat and Power Company*, Direct Testimony of Alexander J. Torok, at 7)
[10] *Id*, p. 7. (citing Case No. 2004-00103, February 28, 2005 Order at 65-66)
[11] *Id*, p. 8

income tax rate could well be viewed as forcing the utility to use these non-regulated activities to subsidize the regulated utility operations."[12]

[12] *Id*, p 8

Corporate Policies and Guidelines for Intercompany Transactions
Responding Witness – Valerie L. Scott

Corporate Policies and Guidelines for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), their Holding Company, LG&E Energy Corp. ("LG&E Energy") and any non-utility subsidiary created by LG&E Energy. As nonutility subsidiaries are created by LG&E Energy, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's or KU's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E, KU and LG&E Energy, to the extent practicable, each subsidiary of LG&E Energy will acquire and maintain its own facilities, equipment, staff and financing.

2. <u>Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility</u>.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utilities or their customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E or KU to LG&E Energy or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E or KU from LG&E Energy or any of LG&E Energy's non-utility subsidiaries. Transfers or sales of assets between LG&E and KU will be priced at cost. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utilities will receive the full benefit from intercompany transfers or sales.

LG&E or KU shall furnish a report to the PSC annually of each transfer of utility assets between themselves or between LG&E or KU and LG&E Energy or any of its non-utility subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All goods or services provided by LG&E or KU to LG&E Energy or any of its non-utility subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E and KU will utilize their automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are

accounted for in accordance with management's policies and guidelines.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities. Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

LG&E Energy and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E and KU shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

LG&E Energy will file consolidated Federal and State income tax returns which will include LG&E's, KU's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

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KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
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Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 37

Responding Witness: Shannon L. Charnas

Q-37. Refer to KU's response to Staffs Second Request, Item 122. Explain why maintenance contracts by vendor increased from $9 million to $16.2 million during the years 2006 to 2007.

A-37. Maintenance contracts by vendor primarily increased from $9 million to $16.2 million during the years 2006 to 2007 due to the following:

- Bray Electric Services Inc – increased $0.1 million, new consolidated agreement for Transmission project inspection.
- C E Power Solutions LLC – increased $0.4 million, new consolidated contract for sub-station maintenance services.
- Charah Inc – increased $0.5 million, landfill management work at Brown and Green River stations.
- Evans Construction Co Inc – increased $0.8 million, incorporation of light maintenance work at Operations Centers and Business Offices statewide.
- Mechanical Construction Services Inc – increased $0.8 million, scheduled boiler outage repair work.
- Mechanical Dynamics and Analysis LLC – increased $0.6 million, consolidated fleet wide turbine-generator overhaul agreement and scheduled outages.
- PIC Energy Services Inc – increased $0.6 million, scheduled boiler outage repair work and consolidated agreement.
- Siemens Power Generation Inc – increased $3.1 million, scheduled Ghent Station turbine-generator overhaul work.
- Various other maintenance agreements for new systems.

As all the costs listed above relate to on-going inspection and maintenance, the costs are considered recurring.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
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Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 38

Responding Witness: Paul W. Thompson / Shannon L. Charnas

Q-38. Refer to KU's response to Staffs Second Request, Item 132(c).

a. For the 12-month periods ended April 30, 2004, 2005, and 2006, provide the amount of expense recorded to Account 512, Maintenance of Boiler Plant.

b. For each of the 12-month periods ended April 30, 2004, 2005, and 2006, identify the generating units which had a scheduled maintenance outage similar to the one that occurred during the test year at Brown Steam Unit 1.

c. For each of the calendar years 2009, 2010, and 2011, identify which KU generating units are planned to have a scheduled maintenance outage similar to the one that occurred during the test year at the Brown Steam Unit 1.

A-38. a. Expense recorded in Account 512, Maintenance of Boiler Plant for the 12-month periods ended April 30, 2004, 2005, and 2006 were:

2004	$16,455,257
2005	$21,632,969
2006	$18,282,990

b. The Brown 1 outage in the test year was a major overhaul. The list below contains all of the major overhauls in the 12-month periods requested. In general, each KU coal-fired unit has a scheduled annual maintenance outage.

May 1, 2003 – April 30, 2004:	Tyrone 3*	Major Turbine Overhaul
	Brown 3**	Major Boiler Overhaul

May 1, 2004 – April 30, 2005:	Brown 3*	Major Boiler Overhaul
	Green River 4	Major Boiler Overhaul
	Ghent 2**	Major Turbine Overhaul
	Brown 3**	Major Turbine Overhaul

May 1, 2005 – April 30, 2006:	Ghent 2*	Major Turbine Overhaul
	Brown 3*	Major Turbine Overhaul

* - continued from previous 12-month period

** - continues into next 12-month period

c. The Brown 1 outage in the test year was a major overhaul. The list below contains all of the planned major overhauls in the years requested.

January 1, 2009 – December 31, 2009:	Brown 2	Major Overhaul
	Green River 3	Major Overhaul

January 1, 2010 – December 31, 2010:	Ghent 3	Major Overhaul
	Tyrone 3	Major Overhaul

January 1, 2011 – December 31, 2011:	None	

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Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 39

Responding Witness: Paul W. Thompson / Shannon L. Charnas

Q-39. Refer to KU's response to Staffs Second Request, Item 132(d).

a. For the 12-month periods ended April 30, 2004, 2005, and 2006, provide the amount of expense recorded to Account 513, Maintenance of Electric Plant.

b. For each of the 12-month periods ended April 30, 2004, 2005, and 2006, identify the generating units which had a scheduled major boiler/turbine outage similar to the one that occurred during the test year at Ghent Unit 1.

c. For each of the calendar years 2009, 2010, and 2011, identify which KU generating units are planned to have a scheduled major boiler/turbine outage similar to the one that occurred during the test year at Ghent Unit 1.

A-39. a. Expense recorded in Account 513, Maintenance of Electric Plant for the 12-month periods ended April 30, 2004, 2005, and 2006 were:

2004	$5,365,242
2005	$6,165,247
2006	$9,492,089

b. The Ghent 1 outage in the test year was a major overhaul. Please see response to Question No. 38(b).

c. The Ghent 1 outage in the test year was a major overhaul. Please see response to Question No. 38(c).

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Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 40

Responding Witness: Paul W. Thompson

Q-40. Refer to KU's response to Staff's Second Request, Item 132(e). Clarify the meaning of Trimble County Combustion Turbine outage work.

A-40. The increase in cost that was referenced in Item 132(e) for FERC Account 548 was for the combustion inspection outage work performed on Trimble County Combustion turbine units 7 and 10 in accordance with Original Equipment Manufacturer (OEM) standards. Combustion inspections generally take place after 450 factored starts on the General Electric type units that are in place at Trimble County. At April 30, 2008, Trimble County Unit 7 had 482 factored starts, and Trimble County Unit 10 had 396 factored starts. The Unit 10 compressor needed repair, and to minimize total outage time on the unit, the combustion inspection was conducted during the outage rather than waiting until the unit had reached 450 factored starts.

A factored start is a fired start on a given unit, adjusted upward on a sliding scale for any situations in which the unit trips (stops generating power), and what the operating parameters were at the time of that trip, such as the load on the unit and the exhaust temperature.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
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Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 41

Responding Witness: Lonnie E. Bellar

Q-41. In various data responses, KU has noted errors and amendments necessary to correct or update its original application. Provide a summary which identifies all such errors and amendments and which shows their overall impact on the amount of KU's proposed rate increase.

A-41. In order to incorporate other changes identified through the Third Data Request of Commission Staff and Supplemental Data Request of the Intervenors, the Company will prepare the requested information and file it with the Commission no later than October 10, 2008.