KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 88

Responding Witness: William E. Avera

Q-88. With reference to pages 39-41 and Schedule WEA-7, please (1) list all regulatory cases (by name, docket number, and filing date) in which Dr. Avera has provided rate of return testimony and employed his Expected Earnings Approach to estimating the cost of equity capital, (2) indicate all cases (by name, docket number, and date) other than those cited, in which a regulatory commission has explicitly adopted Dr. Avera's Expected Earnings Approach to estimating the cost of equity capital in arriving at an overall rate of return, and (3) provide copies of the 'Rate of Return' section of the Commission's decisions for all cases in which a regulatory commission has adopted the Dr. Avera's Expected Earnings Approach.

A-88. Dr. Avera has submitted testimony in 270 proceedings and does not maintain a database to identify the specific approaches and methods applied in each case involving rate of return on equity. Nevertheless, Dr. Avera has consistently noted that the opportunity to earn returns comparable with those offered by firms of similar risk is a fundamental economic and regulatory principle underlying a fair rate of return on equity. In those instances where Dr. Avera has not presented the expected earnings approach applied directly to the proxy companies used to estimate the cost of equity, he has nevertheless considered earned returns on equity as a check of reasonableness in his evaluation and recommendations.

Dr. Avera does not have in his possession copies of all Commission orders in each proceeding in which he has testified. Regulators have customarily considered the results of alternative approaches in determining allowed returns and it is widely recognized that no single method can be regarded as a panacea; all approaches having their own advantages and shortcomings. For example, "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996), reported that 19 U.S. regulatory jurisdictions specifically consider earned rates of return, while 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. Similarly, "The Cost of Capital – A Practitioner's Guide," prepared for the Society of Utility and Regulatory Financial Analysts, noted that reference to comparable earned rates of return was "the granddaddy of cost of equity methods" and concluded that the method "is easily understood and is firmly anchored in regulatory tradition (i.e., Bluefield and Hope).

Dr. Avera's testimony, and the Commission decisions in each of the cases in which he has testified is publicly available from the respective regulatory jurisdictions. A listing of Dr. Avera's regulatory testimony, including the utility, jurisdiction, case number, and date is also attached, along with copies of the source materials referenced above.

WILLIAM E. AVERA

SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	El Paso Electric Company	Texas PUC	522	Mar-78	Residential Rate Structure
2.	Texas Power & Light Company	Texas PUC	1517	Mar-78	Rate Design
3.	Lower Colorado River Authority	Texas PUC	1521	Mar-78	Rate Design
4.	Dallas Power & Light Company	Texas PUC	1526	Mar-78	Rate Design
5.	Gulf States Utilities	Texas PUC	1528	Apr-78	Rate of Return
6.	Continental Telephone	Texas PUC	1529	Mar-78	Rate of Return
7.	Southwestern Bell Telephone Company	Texas PUC	1704	May-78	Rate of Return
8.	Texas Electric Service Co., Texas Power & Light Co., Dallas Power & Light Co.	Texas PUC	1517, 1813, 1903	Feb-79	Fuel Cost Refunds and Fuel Adjustment Clauses
9.	Houston Lighting & Power Company	Texas PUC	2001	Sep-78	Rate of Return
10.	Kimble Electric Cooperative	Texas PUC	2380	Mar-79	Rate of Return
11.	Lower Colorado River Authority	Texas PUC	2503	Jun-79	Rate of Return
12.	Southwestern Bell Telephone Company	Texas PUC	3340	Sep-80	Rate of Return
13.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Rate of Return
14.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
15.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	None	Sep-81	Equity Contributions
16.	Connecticut Light & Power Company, Hartford Electric Light Company	Connecticut DPUC	810602 & 810604	Sep-81	Rate Structure
17.	Delmarva Power & Light Company	Delaware PSC	81-12	Oct-81	Relative Customer Class Risk
18.	Chemical Express Carriers	Texas RRC	024777ZZT	Dec-81	Rate Design
19.	Owentown Gas Company	Texas RRC	2720	Jan-82	Historical Transactions and Regulatory Policy
20.	Guadalupe Valley Electric Cooperative	Texas PUC	4516	Aug-82	Relative Customer Class Risk
21.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Rate of Return

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Summary of Testimony Before Regulatory Agencies
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
22.	Cinncinati Gas & Electric Company	Ohio PUC	82-485-EL-AIR	Jan-83	CWIP Inclusion in Rate Base
23.	Gencom Inc.	FCC	Various	Dec-83	Rate Comparisons
24.	Public Service of Oklahoma	Oklahoma CC	28665	Jan-84	Avoided Costs for QFs
25.	Public Service of Oklahoma	Oklahoma CC	28754	Apr-84	Avoided Costs for QFs
26.	Texas-New Mexico Power Company	Texas PUC	5568	Apr-84	Relative Customer Class Risk
27.	Kansas Gas & Electric Company	Kansas CC	84-KG&E-197-R; 142098-U	Oct-84 Jun-85	Rate of Return and Effects of Regulation on Securities
28.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Risk Premium Cost of Equity Formula
29.	Southwestern Public Service Company	Texas PUC	6055	Mar-85	PURA NOI Regulatory Policy
30.	Kansas City Power & Light Company	Missouri PSC	ER-85-128; ER-85-185	Aug-85	Comparative Costs of Nuclear Plants
31.	Southwestern Electric Power Company	Texas PUC	6242	Oct-85	Avoided Energy Costs
32.	Westar Transmission Company	Texas RRC	5787	Nov-85	Rate Design
33.	City of Austin Electric Department	Texas PUC	6560	Jan-86	Cost-Based Rates and Relative Customer Class Risk
34.	Southwestern Bell Telephone Company	Missouri PSC	TR-86-84	Mar-86	Risk Premium Cost of Equity
35.	Enstar Natural Gas Company	Alaska PUC	U-68-8	Apr-86	Regulatory Treatment of Settlement Payments
36.	Kansas Gas & Electric Company	FERC	ER-85-461-001, et al.	Apr-86	Regulatory Policy Surrounding Nuclear Plant Cost
37.	Houston Lighting & Power Company	Texas PUC	5994	May-86 Jun-86 Jul-86	Avoided Energy Costs and Capacity Value of Non-firm QF Energy
38.	Southwestern Electric Power Company	Texas PUC	6611	Aug-86	Avoided Energy Costs
39.	Celanese Chemical Company, Inc.	Texas RRC	5848 et al.	Aug-86 Nov-86	Regulatory Policy Re: BTU Refunds

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Summary of Testimony Before Regulatory Agencies
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
40.	Houston Lighting & Power Company	Texas PUC	7044	Nov-86 Jan-87 Feb-87 Mar-87	Interim Rate Relief and Pricing of Firm and Non-firm Energy
41.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Regulatory Policy Re: Contracts
42.	El Paso Electric Company	Texas PUC	7460	Jul-87	Nuclear Plant Capacity Treatment
43.	West Texas Utilities Company	Texas PUC	7510	Aug-87	Customer Class Risk
44.	Lower Colorado River Authority	Texas PUC	8032	Jun-88	Revenue Requirements
45.	City of Austin Electric Department	Austin City Council	--	Jun-88	Cost-Based Rates and Relative Customer Class Risk
46.	Southwestern Bell Telephone Company	Missouri PSC	TC-89-14	Nov-88	Risk Premium Cost of Equity and Divisional Cost of Capital
47.	Houston Lighting & Power Company	Texas PUC	8046	Jan-89 Oct-89 Mar-90	Limitation of Liability
48.	Southwestern Bell Telephone Company	Texas PUC	8585	May-89 Nov-89 Mar-90	FIT, Risk Premium Cost of Equity, and Stipulation
49.	Kansas Gas & Electric Company	Kansas CC	84-KG&E-197-R; 142098-U	Oct-89	Financial Impacts of Intervenor Proposals
50.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
51.	North Carolina Power	N. Carolina Util. Comm.	E-22, Sub 314	May-90 Nov-90	Rate of Return on Equity
52.	Burlington Northern Railroad	ICC	40224	Jun-90	Coal Transportation Rates
53.	Lower Colorado River Authority	Texas PUC	9427	Aug-90 Sep-90	Debt Service Coverage
54.	Brazos River Authority	Texas Water Commission	8169-M	Aug-90 Dec-90	Contract Rates
55.	Texas-New Mexico Power Company	Texas PUC	9491	Sep-90	Avoided Cost Policy and History

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Summary of Testimony Before Regulatory Agencies
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
56.	Southern Bell Telephone Company	S. Carolina PSC	90-626-C	Dec-90	Rate of Return on Equity
57.	Public Service Co. of Colorado	Colorado PUC	91S-091EG	Jan-91	Rate of Return on Equity
58.	Southwestern Bell Telephone Company	Oklahoma CC	PUD 00662 000837	Mar-91 Sep-91 Sep-91 Sep-91	Rate of Return and Incentive Regulation Plans
59.	Cincinnati Gas & Electric Company	Ohio PUC	91-410-EL-AIR	Apr-91	Rate of Return on Equity
60.	City of Fort Worth Water Department	Texas Water Commission	8291-A; 8748-A	Apr-91	Regulatory Policy
61.	El Paso Electric Company	Texas PUC	9945	May-91	Regulatory History
62.	Public Service Co. of Colorado	Colorado PUC	90F-226E	May-91	Rate of Return on Equity
63.	Southwestern Bell Telephone Company	Texas PUC	10382; 10381	Sep-91 Oct-91	Incentive Regulation Plan
64.	Virginia Electric and Power Company	Virginia Corp. Comm.	PUE-910047	Oct-91 Jan-92	Rate of Return on Equity
65.	State Farm Fire and Casualty, and Automobile Insurance Company	Texas Board of Insurance	1845 1846	Nov-91 Dec-91 Dec-91 Dec-91	Regulatory Policy
66.	Texas-New Mexico Power Company	Texas PUC	10200	Dec-91	Avoided Cost Policy and History
67.	Allegheny Generating Company	FERC	ER92-242-000	Apr-92 May-92	Rate of Return on Equity
68.	Southwestern Bell Telephone Company	Arkansas PSC	91-204-U	Apr-92	Incentive Regulation Plans
69.	Virginia Electric and Power Company	Virginia Corp. Comm.	PUE-920041	May-92 Mar-93	Rate of Return on Equity
70.	The Potomac Edison Company	Maryland PSC	8469	Jul-92 Dec-92	Rate of Return on Equity
71.	North Carolina Power	N. Carolina Util. Comm.	E-22, Sub 333	Jul-92 Jan-93	Rate of Return on Equity
72.	West Penn Power Company	Pennsylvania PUC	R-0092-2378	Aug-92 Dec-92	Rate of Return on Equity

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
73.	U.S. Telephone Association	FCC	92-133	Sep-92	Rate of Return Represcription Policy
74.	Cincinnati Gas & Electric Company	Ohio PUC	92-1463-GA-AIR; 92-1464-EL-AIR	Sep-92	Rate of Return on Equity
75.	Southwestern Electric Power Company	Texas PUC	9655	Sep-92	Settlement – Avoided Costs
76.	Texas Automobile Insurance Plan	Texas Board of Insurance	1932	Jan-93 Feb-93	Cost-based Rates
77.	Public Service Co. of Colorado	Colorado PUC	93S-001EG	Jan-93 Jun-93	Rate of Return on Equity
78.	Southwestern Bell Telephone Company	Missouri PSC	T0-93-192; TC-93-224	Feb-93 May-93 Jun-93	Incentive Regulation and Rate of Return on Equity
79.	Entergy/Gulf States Utilities	Texas PUC	11292	Feb-93	Reasonableness of Purchase Price
80.	AGT Limited	Canadian Radio-Tel. & Tel. Comm.		Apr-93 Aug-93	Rate of Return on Equity
81.	The Potomac Edison Company	Virginia Corp. Comm.	PUE-930033	Apr-93	Rate of Return on Equity
82.	Southwestern Bell Telephone Company	Arkansas PSC	92-260-U	Jun-93 Sep-93	Incentive Regulation and Rate of Return on Equity
83.	Pond Branch Telephone Company	S. Carolina PSC	93-750-C	Feb-94	Rate of Return
84.	West Penn Power Company	Pennsylvania PUC	R-0094-2986	Mar-94 Aug-94	Rate of Return on Equity
85.	The Potomac Edison Company	West Virginia PSC	94-0027-E-T	Apr-94 Aug-94	Rate of Return on Equity
86.	Monongahela Power Company	West Virginia PSC	94-0035-E-42T	Apr-94 Aug-94	Rate of Return on Equity
87.	The Potomac Edison Company	Maryland PSC	8652	Apr-94	Rate of Return on Equity
88.	Texas Utilities Electric Company	Texas PUC	13100	Jun-94 Aug-94	Competitive and Developmental Rates

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
89.	El Paso Electric Company	Texas PUC	12700	Jun-94	Interruptible Rates
90.	The Potomac Edison Company	Virginia CC	PUE-94005	Jun-94 Nov-94	Rate of Return on Equity
91.	Idaho Power Company	Idaho PUC	IPC-E-94-5	Jun-94 Dec-94	Rate of Return on Equity
92.	Chevron Pipe Line Company	ICC	40131	Jun-94	Rate of Return
93.	Houston Lighting and Power Company	Texas PUC	12065	Jul-94	Federal Income Tax and Regulatory Policy
94.	Allegheny Generating Company	FERC	EL94-24-000	Sep-94	Rate of Return on Equity
95.	The Potomac Edison Company	FERC	EL95-39-000	Oct-94	Rate of Return on Equity
96.	AGT Limited	Canadian Radio-Tel. & Tel. Comm.	94-58	Jan-95	Rate of Return on Equity Policy
97.	Southwestern Bell Telephone Company	Texas PUC	13282	Feb-95	CCN Policy
98.	Monongahela Power Company	Ohio PUC	94-1918-EL-AIR	Feb-95	Rate of Return on Equity
99.	Duke Power Company	FERC	EL95-0	Feb-95	Rate of Return on Equity
100.	Farmers Telephone Cooperative, Inc.	South Carolina PSC	94-024-C	Mar-95	Rate of Return
101.	Southern Company Services, Inc.	FERC	EL94-85-0	Mar-95	Rate of Return on Equity
102.	Burlington Northern Railroad	ICC	41191 (SEALED)	May-95 Aug-95	Market Dominance
103.	Burlington Northern and Santa Fe Railroads	ICC	Finance 32549	Jun-95	Merger Impact on Competition
104.	Southern New England Telephone	Connecticut DPUC	95-03-01	Jun-95	Rate of Return on Equity
105.	West Texas Utilities Company	Texas PUC	13369	Jul-95	Regulatory Policy
106.	Calaveras Telephone Company	California PUC	95-12-075	Dec-95 Sep-96	Rate of Return
107.	California-Oregon Telephone Co.	California PUC	95-12-073	Dec-95 Sep-96	Rate of Return

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
108.	Ducor Telephone Company	California PUC	95-12-076	Dec-95 Sep-96	Rate of Return
109.	Foresthill Telephone Co.	California PUC	95-12-078	Dec-95 Sep-96	Rate of Return
110.	Sierra Telephone Company, Inc.	California PUC	95-12-077	Dec-95 Sep-96	Rate of Return
111.	Southwestern Bell Telephone Company	Texas PUC	14659	Jan-96	Rate of Return
112.	Southern Company Services, Inc.	FERC	ER95-1468-000	Jan-96	Rate of Return on Equity
113.	Duke Power Company	FERC	ER95-760-000	Feb-96	Rate of Return on Equity
114.	Allegheny Power Service Corp.	FERC	ER96-58-000	Feb-96	Rate of Return on Equity
115.	Duke Power Company	FERC	EL95-31-000	Mar-96 May-96	Rate of Return on Equity
116.	Allegheny Generating Company	FERC	EL96-33-000	Apr-96	Rate of Return on Equity
117.	Southern Company Services, Inc.	FERC	ER95-1468-000	Jul-96	Rate of Return on Equity
118.	Southwestern Bell Telephone Company	Texas PUC	16189, et al.	Sep-96	Rate of Return
119.	Southwestern Bell Telephone Company	Missouri PSC	TO-97-40 TO-07-67	Sep-96 Sep-96	Rate of Return
120.	Southwestern Bell Telephone Company	Arkansas PSC	96-257-U	Sep-96	Rate of Return
121.	Southwestern Bell Telephone Company	Oklahoma CC	PUD 960 000 218	Sep-96 Sep-96	Rate of Return
122.	General Telephone of the Southwest	Texas PUC	16300 16335	Oct-96	Rate of Return
123.	Southwestern Bell Telephone Company	Kansas CC	97-SCCC-167-ARB	Nov-96	Rate of Return
124.	Southern Company Services, Inc.	FERC	ER96-1794-000	Nov-96	Rate of Return on Equity

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
125.	General Telephone of the Southwest	Texas PUC	16402	Nov-96	Rate of Return
126.	General Telephone of the Southwest	Texas PUC	16473 16476	Nov-96	Rate of Return
127.	Southwestern Bell Telephone Company	Arkansas PSC	96-395-U	Dec-96 Jan-97	Rate of Return
128.	Southwestern Bell Telephone Company	Kansas CC	97-AT&T-290-ARB	Dec-96 Jan-97	Rate of Return
129.	El Paso Electric Company	New Mexico PUC	2722	Mar-97 Jun-98	Rate of Return
130.	Telus Communications, Inc.	Canadian Radio-Tel. & Tel. Comm.	PN 97-11	Jun-97	Rate of Return on Equity
131.	West Penn Power Company	Pennsylvania PUC	R-0097-3981	Aug-97	Rate of Return on Equity and Competition
132.	Southwestern Bell Telephone Company	Oklahoma CC	PUD 970 000 213	Aug-97	Rate of Return
133.	Connecticut Light and Power Company	Connecticut DPUC	97-05-12	Sep-97 Oct-97	Rate of Return on Equity
134.	Southwestern Bell Telephone Company	Texas PUC	16189, et al.	Sep-97	Rate of Return
135.	DQE, APS, and AYP Sub, Inc.	Pennsylvania PUC	A-1101; 50F-0015	Sep-97	Rate of Return on Equity
136.	FirstEnergy Corporation	FERC	ER97-412-000; ER97-413-000	Oct-97 Jun-98	Rate of Return on Equity
137.	Southwestern Bell Telephone Company	Oklahoma CC	PUD 970 000 442	Nov-97	Rate of Return
138.	Maui Electric Company	Hawaii PUC	97-0346	Dec-97	Diversification and Cost of Capital
139.	Hawaii Electric Light Company	Hawaii PUC	97-0420	Mar-98	Diversification and Cost of Capital
140.	Duke Energy Moss Landing, LLC	FERC	ER98-2668-000	Apr-98	Rate of Return on Equity
141.	Duke Energy Oakland, LLC	FERC	ER98-2669-000	Apr-98	Rate of Return on Equity

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
142.	Southwestern Bell Telephone Company	Kansas CC	97-SCCC-149-GIT	Jun-98	Rate of Return
143.	The Potomac Edison Company	Maryland PSC	8738	Jun-98 Mar-99	Rate of Return on Equity
144.	Allegheny Power Service Corp.	FERC	ER98-2048-000	Jun-98	Rate of Return on Equity
145.	Union Pacific Railroad	STB	32760	Jul-98	Regulatory Policy
146.	The Washington Water Power Company	Idaho PUC	WWP-E-98-11	Dec-98 May-99	Rate of Return
147.	Interstate Access Carriers	FCC	CC Docket 98-166	Jan-99 Mar-99 Apr-99	Rate of Return Policy
148.	FirstEnergy Corporation	FERC	ER99-2609-000	Apr-99	Rate of Return on Equity
149.	Union Pacific Railroad	STB	Fin Doc. No. 33726	May-99 Jun-99	Regulatory Policy
150.	Nevada Bell Telephone Company	Nevada PUC	98-6004	May-99 Jan-00	Cost of Capital Study
151.	Monongahela Power Company & Potomac Edison Company	West Virginia PSC	98-0453-E-GI	Jul-99	Rate of Return on Equity
152.	Avista Corp.	Washington UTC	UE-99-1606; UG-99-1706	Oct-99 May-00	Cost of Capital
153.	Hawaii Electric Light Company	Hawaii PUC	99-0207	Oct-99 Jun-99	Diversification and Cost of Capital
154.	Dayton Power & Light Company	Ohio PUC	99-1687-EL-ETP	Dec-99	Rate of Return on Equity
155.	Southern New England Bell	Connecticut DPUC	00-01-02	Apr-00	Cost of Capital
156.	El Paso Electric Company	New Mexico PUC	3170	Jun-00	Rate of Return on Equity
157.	Wisconsin Bell Telephone Co.	Wisconsin PSC	6720-T1-161	Jun-00 Feb-01	Cost of Capital
158.	Ameritech-Illinois	Illinois CC	98-0252	Jul-00 Dec-00 Jan-01	Economy and Risk

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
159.	American Transmission Co., LLC	FERC	ER00-3316-000	Jul-00	Cost of Capital
160.	Ameritech-Indiana	Indiana URC	40849, 40785-51 & 41058	Sep-00	Cost of Capital
161.	Burlington Northern Santa Fe, Inc.	STB	42054	Mar-01	Implications of Deregulation & Coal Plant Utilization
162.	Avista Corp.	Washington UTC	UE-010395	Mar-01	Power Cost Deferral and Cost of Equity
163.	Rural Telephone Co.	Kansas CC	01-RRLT-083-AUD	Apr-01	Cost of Capital
164.	El Paso Electric Co.	New Mexico PRC	3606	Apr-01	Rate of Return on Equity
165.	Southwestern Bell Telephone Co.	Missouri PSC	TO-2001-455	Apr-01	Cost of Capital
166.	Southwestern Bell Telephone Co.	Missouri PSC	TO-2001-438	Jun-01 Nov-01	Cost of Capital
167.	Commonwealth Edison Co.	FERC	ER01-2992-000	Aug-01	Rate of Return on Equity
168.	Craw-Kan Telephone Cooperative	Kansas CC	01-CRKT-713-AUD	Oct-01	Cost of Capital
169.	TransConnect, LLC	FERC	RT01-15-0000	Nov-01	Rate of Return on Equity
170.	Midwest ISO	FERC	ER02-485-000	Nov-01 Mar-02	Rate of Return on Equity
171.	Avista Corp.	Washington UTC	UE-011595	Dec-01	Cost of Capital
172.	Southwestern Bell Telephone Co.	Missouri PSC	TO-2002-222	Dec-01	Cost of Capital
173.	Kerman Telephone Company	California PUC	0201004	Jan-02 Feb-03	Cost of Capital
174.	Florida Power & Light Co.	Florida PSC	001148-EI	Jan-02	Rate of Return on Equity
175.	Ameritech Indiana	Indiana URC	40611-S1	Feb-02	Cost of Capital
176.	Southwestern Bell Telephone Co.	Texas PUC	25188	Mar-02	Cost of Capital

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
177.	Citizens Communications Co.	Arizona CC	E-01032C-00-0751	Mar-02 Mar-02	Power Cost Deferral and Regulatory Policy
178.	Blue Valley Telephone Company	Kansas CC	02-BLVT-377-AUD	Jul-02	Cost of Capital
179.	Florida Power & Light Co.	Florida PSC	020262-EI, 020263-EI	Jul-02 Sep-02	Financial Impact of Purchased Power
180.	S&T Telephone Cooperative.	Kansas CC	02-S&TT-390-AUD	Jul-02	Cost of Capital
181.	SBC Pacific Bell	California PUC	01-02-024, et al.	Oct-02 Feb-03 Mar-03	Cost of Capital
182.	Southwestern Bell Telephone	Texas PUC	25834	Nov-02	Cost of Capital
183.	SBC Illinois	Illinois CC	02-0864	Dec-02 Jan-04 Mar-04	Cost of Capital
184.	International Transmission Co.	FERC	EC03-40-000	Dec-02	Rate of Return on Equity
185.	Kansas Gas Service	Kansas CC	03-KGSG-602-RTS	Jan-03 Aug-03	Cost of Capital
186.	Westar Energy, Inc.	Kansas CC	01-WSRE-949-GIE	Feb-03	Impact of Restructuring Plan on Financial Integrity
187.	Avista Corporation	Oregon PUC	UG-153	Apr-03	Rate of Return on Equity
188.	SBC Michigan	Michigan PSC	U-13531	May-03 Mar-04	Cost of Capital
189.	Humboldt Telephone Co.	Nevada PUC	03-7011	Jul-03 Oct-03	Cost of Capital
190.	SBC Indiana	Indiana URC	42393	Jul-03 Sep-03	Cost of Capital
191.	El Paso Electric Co.	New Mexico PRC	03-___UT	Jul-03	Rate of Return on Equity
192.	Northeast Utilities Service Co.	FERC	ER03-1247-000	Aug-03	Rate of Return on Equity
193.	Sierra Pacific Resources Operating Cos.	FERC	ER03-1328-000	Sep-03	Rate of Return on Equity

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
194.	Idaho Power Company	Idaho PUC	IPC-E-03-13	Oct-03 Mar-04	Rate of Return on Equity
195.	Nevada Power Co.	Nevada PUC	03-10002	Oct-03 Jan-04	Rate of Return on Equity
196.	Sierra Pacific Power Co.	Nevada PUC	03-12002	Oct-03 Mar-04	Rate of Return on Equity
197.	The Allegheny Power System Operating Companies, *et al.* (PJM Interconnection Transmission Owners)	FERC	ER04-156-000	Oct-03	Rate of Return on Equity and Cost/Benefit of Incentives
198.	Bangor Hydro-Electric Company, *et al.* (New England Transmission Owners)	FERC	ER04-157-000	Nov-03 Oct-04 Dec-04 Jan-05 Dec-06	Rate of Return on Equity
199.	SBC Texas	Texas PUC	28600	Dec-03 Jan-04	Cost of Capital
200.	SBC Communications, Inc.	FCC	WC 03-173	Jan-04	Cost of Capital Methodology
201.	Avista Corp.	Idaho PUC	AVU-E-04-01; AVU-G-04-01	Feb-04 Jul-04	Rate of Return on Equity
202.	Florida Power & Light Co.	Florida PSC	040206-EU	Mar-04	Financial Impact of Purchased Power
203.	SBC Wisconsin	Wisconsin PSC	6720-TI-187	Mar-04 Jul-04	Cost of Capital
204.	SBC Ohio	Ohio PSC	02-1280-TP-UNC	Mar-04	Cost of Capital
205.	Avista Corp.	Washington UTC	UG-041515	Aug-04	Rate of Return on Equity
206.	Sierra Pacific Resource Operating Cos.	FERC	ER05-14-000	Sep-04	Rate of Return on Equity
207.	PACIFICORP	Utah PSC	04-035-30	Oct-04	Financial Impacts of Purchased Power
208.	Hawaii Electric Company	Hawaii PUC	04-0113	Nov-04	Diversification and Cost of Capital
209.	SBC Arkansas	Arkansas PSC	04-109-U	Nov-04 May-05	Cost of Capital

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
210.	KanOkla Telephone Association, Inc.	Kansas CC	05-KOKT-060-AUD	Nov-04	Cost of Capital
211.	Oklahoma Natural Gas Co.	Oklahoma CC	PUD 200400610	Jan-05 Jun-05	Cost of Capital
212.	Baltimore Gas and Electric Co., *et al.*	FERC	ER-05-515-000	Jan-05	Rate of Return on Equity
213.	Florida Power & Light Co.	Florida PSC	041291-EI	Mar-05	Storm Cost Recovery and Rate of Return on Equity
214.	Avista Corp.	Washington UTC	UE-050482 UG-050483	Mar-05 Sep-05	Rate of Return on Equity
215.	Florida Power & Light Co.	Florida PSC	050045-EI	Mar-05 Jul-05	Rate of Return on Equity
216.	Baltimore Gas and Electric Co.	Maryland PSC	9036	May-05 Sep-05 Sep-05	Rate of Return on Equity
217.	Westar Energy, Inc.	FERC	ER05-925-000	May-05	Rate of Return on Equity
218.	Westar Energy, Inc.	Kansas CC	05-WSE-981-RTS	May-05 Oct-05 Oct-05	Rate of Return on Equity
219.	The United Illuminating Co.	Connecticut DPUC	05-06-04	Jul-05	Rate of Return on Equity
220.	Idaho Power Co.	Idaho PUC	IPC-E-05-28	Oct-05	Rate of Return on Equity
221.	PACIFICORP	Utah PSC	03-035-14	Sep-05	Financial Impacts of Purchased Power
222.	Arizona Public Service Co.	Arizona CC	E-01345A-05-0816	Nov-05 Jan-06 Sep-06	Rate of Return on Equity
223.	Idaho Power Co.	FERC	ER06-787	Mar-06 Apr-07	Rate of Return on Equity
224.	CenturyTel	Missouri PSC	TO-2006-0299	Mar-06 Mar-06	UNE Cost Studies & Regulatory Policy
225.	MidAmerican Energy Co.	FERC	ER-96-719 ER05-59	Apr-06	Rate of Return on Equity
226.	Kansas Gas Service	Kansas CC	06-KGSG-1209-RTS	May-06 Oct-06	Cost of Capital

William E. Avera
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
227.	Hawaii Electric Light Company, Inc.	Hawaii PUC	05-0315	May-06	Diversification and Cost of Capital
228.	Duke Power Company LLC	FERC	ER06-1040	May-06	Rate of Return on Equity
229.	Black Hills Power, Inc.	South Dakota PUC	EL06-019	Jun-06	Rate of Return on Equity
230.	Pacific Gas & Electric Company	FERC	ER06-1325	Jul-06	Rate of Return on Equity
231.	CPL Retail Energy, LP	Texas PUC	32758	Aug-06	Customer Credits and Regulatory Policy
232.	Monongahela Power Co. & Potomac Edison Co.	West Virginia PSC	06-0960-E-42T	Sep-06 Feb-07	Rate of Return on Equity
233.	Hawaii Electric Company, Inc.	Hawaii PUC	2006-0386	Dec-06	Diversification and Cost of Capital
234.	State Farm Lloyds	Texas Dept. of Insurance	454-06-3176.F	Jan-07 Mar-07	Cost of Capital and Financial Integrity
235.	Maui Electric Company, Ltd.	Hawaii PUC	2006-0387	Feb-07	Diversification and Cost of Capital
236.	Trans-Allegheny Interstate Line Co.	FERC	ER07-562	Feb-07 Nov-07	Rate of Return on Equity
237.	Baltimore Gas and Electric Co.	FERC	ER07-576	Feb-07	Rate of Return on Equity
238.	Cheyenne Light, Fuel and Power Co.	Wyoming PSC	20003-90-ER-7 30005-112-GR-7	Feb-07	Rate of Return on Equity
239.	Commonwealth Edison Co.	FERC	ER07-583	Mar-07	Rate of Return on Equity
240.	Oncor Electric Delivery Company	Texas PUC	34077	Apr-07 Sep-07 Oct-07 Dec-07	Public Interest Determination for Merger
241.	Avista Corp.	Washington UTC	UE-070804 UG-070805	Apr-07	Rate of Return on Equity
242.	Idaho Power Co.	Idaho PUC	IPC-E-07-8	May-07 Jan-08	Rate of Return on Equity
243.	Pacific Gas & Electric Co.	California PUC	07-05-008	May-07 Sep-07	Rate of Return on Equity
244.	American Electric Power Cos.	FERC	ER07-1069	June-07	Rate of Return on Equity
245.	Arizona Public Service Co.	FERC	ER07-1142	Jul-07	Rate of Return on Equity

William E. Avera
Summary of Testimony Before Regulatory Agencies

(Continued)

246. Pacific Gas & Electric Co.	FERC	ER07-1213	Jul-07	Rate of Return on Equity
247. Georgia Power Company	Georgia PSC	24506U	Jul-07	AFUDC and Rate of Return on Internal Funds
248. Pepco Holdings, Inc. *et al.*	FERC	ER08-10	Sep-07	Rate of Return on Equity
249. Avista Corp.	Oregon PUC	UG-181	Oct-07	Rate of Return on Equity
250. Florida Power & Light Co.	Florida PSC	070001-EI	Oct-07	Replacement Power Costs from Nuclear Outage
251. Oklahoma Gas and Electric Co.	FERC	ER08-281	Nov-07	Rate of Return on Equity
252. Pacific Gas & Electric Co.	FERC	ER08-267	Nov-07	Rate of Return on Equity
253. Xcel Energy Services, Inc.	FERC	ER08-313	Dec-07	Rate of Return on Equity
254. Potomac-Appalachian Transmission Highline, LLC	FERC	ER08-386	Dec-07	Rate of Return on Equity
255. Westar Energy, Inc.	FERC	EL08-31	Dec-07	Rate of Return on Equity
256. Indiana Michigan Power Co.	IURC	43306	Jan-08	Rate of Return on Equity
257. Public Service Co. of Colorado	FERC	ER08-527	Feb-08	Rate of Return on Equity
258. Niagara Mohawk Power Company	FERC	ER08-552	Feb-08	Rate of Return on Equity
259. Avista Corp.	Washington UTC	UE-080416 UG-080417	Mar-08	Rate of Return on Equity
260. Arizona Public Service Co.	Arizona CC	E-01345A-08-0172	Mar-08 May-08	Rate of Return on Equity
261. Avista Corp.	Idaho PUC	E-08-01 G-08-01	Mar-08	Rate of Return on Equity
262. Southwestern Public Service Co.	FERC	ER08-749	Mar-08	Rate of Return on Equity
263. Pepco Holdings, Inc. *et al.*	FERC	ER08-686	Mar-08	Rate of Return on Equity
264. Florida Power & Light Co.	Florida PSC	080001-EI	May-08	Replacement Power Costs from Nuclear Outage
265. Aquila, Inc.	Iowa UB	RPU-08-03	May-08	Rate of Return on Equity
266. Idaho Power Co.	Idaho PUC	IPC-E-08-10	Jun-08	Rate of Return on Equity
267. American Electric Power Cos.	FERC	ER08-1329	Jul-08	Rate of Return on Equity
268. Black Hills/Colorado Gas Utility Company, LP	Colorado PUC	08S-290G	Jul-08	Rate of Return on Equity
269. Pacific Gas & Electric Co.	FERC	ER08-1318	Jul-08	Rate of Return on Equity

William E. Avera
Summary of Testimony Before Regulatory Agencies

(Continued)

270. The United Illuminating Co.	Connecticut DPUC	08-07-04	Aug-08	Rate of Return on Equity

AGENCY AUTHORITY OVER RATE OF RETURN

Agency	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return: No ONE method ALL are considered	Discounted cash flow	Comparable earnings test	Earnings-price ratio	Mid point approach	Capital asset pricing model	Risk premium	Other	Duration of wall protection provision influences judgement in determining rate of return
FERC	x	x	x	x							
ALABAMA PSC 12/	x	x		x							Possible
ALASKA PUC	x	x			x						
ARIZONA CC	x	x	x 2/	x 7/							
ARKANSAS PSC	x		x	x 11/							
CALIFORNIA PUC	x	x 1/	x 2/	x	x			x	x	x	Possible
COLORADO PUC	x	x		x 9/	x						
CONNECTICUT DPUC	x	x		x							
DELEWARE PSC	x		x 2/	x	x					x	
D.C. PSC	x	x		x							
FLORIDA PSC	x	x 1/	x 2/								
GEORGIA PSC	x	x	x 2/	x					x	x 8/	
HAWAII PUC	x	x	x 2/							x	
IDAHO PUC	x	x		x 9/	x	x					
ILLINOIS CC	x	x	x 2/				x			x	
INDIANA URC	x		x								
IOWA UB	x	x 1/	x	x					x	x 6/	
KANSAS SCC	x	x		x							
KENTUCKY PSC	x	x	x 2/	x	x	x	x			x	
LOUISANA PSC	x			x							
MAINE PUC	x	10/	x 9/	x							
MARYLAND PSC	x	x		x						x 6/	
MASSACHESETTS DPU	x	x		x 5/						x 5/	
MICHIGAN PSC	x	x	2/	x	x		x	x	x	x	
MINNESOTA PUC	x	x		x							
MISSISSIPPI PSC	x	x		x	x						
MISSOURI PSC 13/	x	x		x							
MONTANA PSC	x	x		x	x						
NEBRASKA PSC 4/											
NEVADA PSC	x	x		x	x	x					Yes
NEW HAMPSHIRE PUC	x	x		x							
NEW JERSEY BPU 12/	x	x	x					x	x	x	
NEW MEXICO PUC	x	x	x 2/	x	x					x	
NEW YORK PSC	x	x	x	x 7/						x	
NORTH CAROLINA UC	x	x	x 2/	x	x			x	x	x	
NORTH DAKOTA PSC	x			x							
OHIO PUC	x	x	x	x 7/						x 7/	No decision
OKLAHOMA CC	x	x		x	x				x	x	
OREGON PUC	x	x 1/		x				x			
PENNSYLVANIA PUC	x	x	x 2/	x	x	x	x			x	Maybe if soon
RHODE ISLAND PUC	x	x	x	x	x	x	x			x 3/	
SOUTH CAROLINA PSC	x	x	x	x				x	x		
SOUTH DAKOTA PUC	x	x			x						
TEXAS RC	x	x	x 2/						x		
UTAH PSC	x	x									
VERMONT PSB	x	x		x	x					x	
VIRGINIA SCC	x	x	x 2/								
WASHINGTON UTC	x	x									
WEST VIRGINIA PSC	x	x	x 2/	x	x			x	x	x	
WISCONSIN PSC	x	x	x 2/	x				x		x	
WYOMING PSC	x		x 2/	x	x			x	x	x	
PUERTO RICO PSC 12/	x	x			x						
VIRGIN ISLAND PSC	x	10/	x 2/	x	x					x	
NATL ENERGY BOARD	x	x	x 14/	x	x			x	x	x	
ALBERTA PUB	x	x	x 2/	x	x					x	
ONTARIO EB	x	x	x 2/		x					x	
QUEBEC NGB	x	x	x 2/							x	

Footnote explanations on following page
ICB = Case-by-Case Basis

AGENCY AUTHORITY OVER RATE OF RETURN
FOOTNOTES

1/ Non-utility investment dollars are always excluded from rate base Where non-utility investment is comparatively small capital ratios are not adjusted When non-utility investment is large we usually remove non-utility investment from equity

2/ Commission favors no single method but rather that which produces the most reasonable results

3/ It may use any method it desires especially in the case of a small company

4/ No Commission regulation of electric or gas utilities

5/ DCF is preferred but the Department approves other methods which check the DCF result risk spread analysis preferred by a slight margin Financial condition of utility also give consideration

6/ DCF is preferred; other methods are considered

7/ No single method, however discounted cash flow is frequently used

8/ Discounted cash flow is used most often but risk premium method used also Determined case by case

9/ DCF has been the preferred method but its results should be checked with other methods

10/ Never an issue before this agency

11/ Agency prefers DCF but any method presented is considered

12/ Commission did not respond to request for update information this data may not be current

13/ DCF has been the preferred method but its results are generally checked with other methods such as risk premium and CAPM

14/ Commission favors no single method but rather that which produces tolls that are just and reasonable

THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

DAVID C. PARCELL

PREPARED FOR THE SOCIETY OF UTILITY
AND REGULATORY FINANCIAL ANALYSTS

1997 EDITION

Author's Note: This manual has been prepared as an educational reference on cost of capital concepts. Its purpose is to describe a broad array of cost of capital models and techniques. No cost of equity model or other concept is recommended or emphasized, nor is any procedure for employing any model recommended. Furthermore, no opinions or preferences are expressed by either the author or the Society of Utility And Regulatory Financial Analysts.

CHAPTER 7

COMPARABLE EARNINGS

The comparable earnings method is the "grandaddy" of cost of equity methods, as it is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is based upon the economic concept of "opportunity cost". As noted previously the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. If, in the opinion of those who save and commit capital, the propective return from a given investment is not equal to that available from other investments of similar risk, the available capital will tend to be shifted to the alternative investments. Through this mechanism, opportunity-cost-driven pricing signals direct capital to its most productive uses; thus, a free enterprise system promotes an efficient allocation of scarce resources.

The established legal standards are consistent with the opportunity cost principle. The two Supreme Court cases most frequently cited (Bluefield and Hope) hold that the return to the equity owners be sufficient to maintain the credit of the enterprise and confidence in its financial integrity; to permit the enterprise to attract required additional capital on reasonable terms; and to provide the enterprise and its investors an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

These three interrelated criteria constitute a succinct statement of the opportunity cost principle. An expected return on equity equal to that which can be realized on alternative investments of corresponding risk will, in turn, be sufficient to assure conidence in the financial integrity of the enterprise, to maintain its credit, and to permit it to attract new capital on reasonable terms.

The comparable earnings method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The comparable earnings method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

It is maintained that the comparable earnings standard is easy to calculate and the amount of subjective judgment required is minimal The method avoids several of the subjective factors involved in other cost of capital methodologies. For example, the DCF method requires the determination of the growth rate contemplated by investors, which is a subjective factor The CAPM requires the specification of several expectational variables, such as market return and beta. In contrast, the comparable earnings approach makes use of simple readily available accounting data.

In addition, this method is easily understood and is firmly anchored in regulatory tradition (i e., Bluefield and Hope). The method is not influenced by the regulatory process to the same extent as market-based methods such as DCF and CAPM. The base to which the comparable earnings standard is applicable is the utility's book common equity, which is much less vulnerable to regulatory influences than stock price which is the base to which the market-based standards are applied. Stock price can be influenced by the actions of regulators.

The rationale for the comparable earnings technique is aptly stated by Morin (1994, 406):

> "Although the Comparable Earnings test does not square well with economic theory, the approach is nevertheless meritorious. If the basic purpose of comparable earnings is to set a fair return rather than determine the true economic return, then the argument is

> academic. If regulators consider a fair return as one that equals the book rates or return earned by comparable risk firms rather than one that is equal to the cost of capital of such firms, the Comparable Earnings test is relevant. This notion of fairness, rooted in the traditional legalistic interpretation of the Hope language, validates the Comparable Earnings test."

Use of Book Returns

The ratio return on common equity is computed as follows:

$$(7.1)\quad ROE = \frac{NIAC}{CE}$$

where: ROE = return on equity

NIAC = net income available for common equity (after preferred dividends)

CE = common stockholders equity.

The return on equity ratio is often regarded as the primary summary measure in traditional ratio analysis (Penman, 1991, 233). Furthermore, a study by Block (1964, 116) notes:

> "Return on equity appears as a direct influence on the price-earnings ratio, re-emerges as a major cause of growth and is seen as a consistent pattern with earnings stability. Even payout is controlled by expectations of profitability."

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 89

Responding Witness: William E. Avera

Q-89. Please provide copies of all empirical studies performed that compare the business, financial, and investment risk of KU to the companies in the (1) Utility Proxy Group, and (2) the Non-Utility Proxy Group.

A-89. Dr. Avera's evaluation of the relative investment risks of KU and the firms in his respective proxy group is fully articulated in his testimony. Dr. Avera did not perform independent empirical studies to evaluate the risks of the above referenced companies; rather, he referenced objective, published benchmarks relied on by investors in evaluating their risk perceptions, which form the basis of their required rate of return. Please also refer to the responses to Question No. 83, Question No. 84, and Question No. 86.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 90

Responding Witness: William E. Avera

Q-90. Please provide copies of the source documents, work papers, and underlying data used in the development of Schedules WEA-1, WEA-2, WEA-3, WEA-4, WEA-5, WEA-6, WEA-7, and WEA-8. Please provide the data and work papers in both hard copy and electronic formats (Microsoft Excel), with all data and formulas intact.

A-90. Please refer to the response to Question No. 81. Electronic copies of Dr. Avera's analyses are included in the attached Excel workbook. Hard copies are not being provided due to the volume of data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 91

Responding Witness: William E. Avera

Q-91. Please provide electronic copies (Microsoft Excel) of Schedules WEA-1, WEA-2, WEA-3, WEA-4, WEA-5, WEA-6, WEA-7, and WEA-8. Please leave all data and formulas intact.

A-91. Please refer to the response to Question No. 90.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 92

Responding Witness: S. Bradford Rives

Q-92. With reference to page 19, line 15, please provide a copy of the S&P document.

A-92. See response to PSC-2 Question No. 136(a).

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 93

Responding Witness: S. Bradford Rives

Q-93. With reference to pages 19-20, please provide copies of the data, source documents, and work papers used to develop the imputed debt from long-term purchased power agreements and the associated capital structure with a common equity ratio of 51.06%. Please provide copies of the source documents, work papers, and data in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-93. The amount of imputed debt is calculated by S&P and the Company does not have access to the calculation. The amount of the imputed debt is shown in the E.ON U.S. report of S&P dated August 30, 2007 which was provided in response to Question No. 77. The reconciliation of the capital structure from Exhibit 2 to the 51.06% ratio is shown below.

KU	Exhibit 2 Column 8	%	Proforma including imputed debt	%
Short-term debt	$ 75,773,623	2.70%	$ 75,773,623	2.62%
Long-term debt	1,252,591,453	44.67%	1,252,591,453	43.34%
Imputed debt	-	0.00%	86,100,000	2.98%
Total Debt	1,328,365,076	47.37%	1,414,465,076	48.94%
Common Equity	1,475,886,011	52.63%	1,475,886,011	51.06%
Total Capitalization	$2,804,251,087		$2,890,351,087	

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 94

Responding Witness: S. Bradford Rives

Q-94. With reference to pages 20-23 and Exhibit 2, please (1) provide copies of the data, source documents, and work papers used to develop the capital structure for the electric and gas operations of the company in Exhibit 2; (2) show the details and magnitude of all adjustments that were made to the capitalization as of April 30, 2008; (3) provide the monthly amounts of short-term debt used in arriving at the short-term debt in the capital structure; (4) provide the monthly cash flow and capitalization amounts, including all actual and pro forma financings. Please provide copies of the source documents, work papers, and data in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-94. The requested information is also provided on CD.

(1) See attached.

(2) See attached adjustments to capitalization:

a) Reacquired Bonds (item (3) on Exhibit 2) were reacquired during April 2008. Short term debt was used to finance the repurchases. The adjustment is to reduce the short term debt and increase the long term debt to "true-up" the actual long term debt amount. See attachment (1), page 2 within.
b) Undistributed Subsidiary Earnings (item (4) on Exhibit) is the undistributed earnings of the investment in EEI (see the Unappropriated Undistributed Subsidiary Earnings provided in attachment (1), page 1 within). See response to Question No. 34.
c) The Investment in EEI (item (5) on Exhibit 2) is the 20% investment in EEI (see Investments in Subsidiary Companies provided in attachment (1) page 1 within). See response to Question No. 34.
d) Investment in OVEC and Other (item (6) on Exhibit 2) is the 2.5% investment in OVEC of $250,000 and Other Investments of $411,140, which consists of community economic development agencies (see Ohio Valley Electric Corporation and Other provided in attachment (1), page 1 within). See response to Question No. 34.

(3) See attachment to response to item (4) within.

(4) See attached for actual financings. There are no pro-forma financings.

Kentucky Utilities Company
Comparative Balance Sheets as of April 30, 2008 and 2007

Assets and Other Debits	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	5,151,234,451.43	4,380,737,063.36
Less Reserves for Depreciation and Amortization	1,972,362,644.75	1,876,367,654.84
Total	3,178,871,806.68	2,504,369,408.52
Investments - at Cost		
Ohio Valley Electric Corporation	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	969,025.81
Investments in Subsidiary Companies	24,880,478.80	19,807,940.00
Special Funds	6,046,655.99	8,140,713.10
Other	411,140.00	426,140.00
Total	31,767,395.73	29,593,818.91
Current and Accrued Assets		
Cash	2,125,603.26	6,086,367.97
Special Deposits	4,334,948.68	20,304,946.92
Temporary Cash Investments	17,681.67	16,924.95
Accounts Receivable-Less Reserve	142,596,743.77	122,698,210.48
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	49,694.17	6,252,255.78
Materials and Supplies-At Average Cost		
Fuel	46,647,686.54	62,663,137.35
Plant Materials and Operating Supplies	28,045,637.93	25,633,096.13
Stores Expense	6,524,614.19	6,079,526.76
Allowance Inventory	223,085.27	1,134,949.48
Prepayments	3,405,611.11	3,563,125.42
Miscellaneous Current and Accrued Assets	-	1,992,267.65
Total	233,971,306.59	256,424,808.89
Deferred Debits and Other		
Unamortized Debt Expense	6,790,525.03	6,494,563.75
Unamortized Loss on Bonds	10,611,577.64	10,473,928.85
Accumulated Deferred Income Taxes	50,537,997.37	45,723,507.74
Deferred Regulatory Assets	82,545,197.75	115,638,664.82
Other Deferred Debits	58,995,218.47	78,979,983.83
Total	209,480,516.26	257,310,648.99
Total Assets and Other Debits	3,654,091,025.26	3,047,698,685.31

Liabilities and Other Credits	This Year	Last Year
Capitalization		
Common Stock	308,139,977.56	308,139,977.56
Common Stock Expense	(321,288.87)	(321,288.87)
Paid-In Capital	115,000,000.00	15,000,000.00
Other Comprehensive Income	-	-
Retained Earnings	1,066,612,042.33	910,723,554.25
Unappropriated Undistributed Subsidiary Earnings	23,584,678.80	18,512,140.00
Total Common Equity	1,513,015,409.82	1,252,054,382.94
Preferred Stock	-	-
Pollution Control Bonds - Net of Reacquired Bonds	316,059,520.00	305,951,140.00
LT Notes Payable to Associated Companies	931,000,000.00	611,000,000.00
Total Long-term Debt	1,247,059,520.00	916,951,140.00
Total Capitalization	2,760,074,929.82	2,169,005,522.94
Current and Accrued Liabilities		
Long-term Debt Due in 1 Year	-	-
ST Notes Payable to Associated Companies	93,302,454.00	62,745,054.00
Notes Payable	-	-
Notes Payable to Associated Companies	-	-
Accounts Payable	134,916,555.69	125,790,911.56
Accounts Payable to Associated Companies	36,181,072.10	102,807,708.17
Customer Deposits	19,792,751.88	18,841,017.05
Taxes Accrued	12,576,638.88	245,947.81
Interest Accrued	11,397,765.18	7,366,575.04
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	13,363,943.14	11,213,750.34
Total	321,531,180.87	329,010,963.97
Deferred Credits and Other		
Accumulated Deferred Income Taxes	331,434,967.30	328,775,200.23
Investment Tax Credit	58,094,343.32	22,701,671.32
Regulatory Liabilities	38,152,787.49	36,654,293.96
Customer Advances for Construction	2,420,052.26	1,984,291.81
Asset Retirement Obligations	30,975,691.02	29,101,856.78
Other Deferred Credits	21,296,038.92	8,355,655.58
Miscellaneous Long-term Liabilities	3,256,903.03	46,913,039.58
Accum Provision for Postretirement Benefits	86,854,131.23	75,196,189.14
Total	572,484,914.57	549,682,198.40
Total Liabilities and Other Credits	3,654,091,025.26	3,047,698,685.31

KENTUCKY UTILITIES COMPANY
ANALYSIS OF THE EMBEDDED COST OF CAPITAL AT
April 30, 2008

LONG-TERM DEBT

	Due	Rate	Principal	Annualized Cost: Interest(Income)	Annualized Cost: Amortized Debt Issuance Expense	Annualized Cost: Premium	Annualized Cost: Amortized Loss-Reaquired Debt	Annualized Cost: Total	Embedded Cost
Pollution Control Bonds -									
Series 11 - Series A	05/01/23	7 87500% *	12 900 000	1.015,875	17.292	-	16,788	1.049.955	8 14
Series 12	02/01/32	1 65000% *	20 930 000	345.345	4.104	-	36,300	385.749	1 84
Series 13	02/01/32	1 65000% *	2.400.000	39 600	2 856	-	4,164	46,620	1 94
Series 14	02/01/32	1 65000% *	7,400.000	122 100	3.180	-	15.660	140.940	1 90
Series 15	02/01/32	1 65000% *	2.400.000	39.600	1.140	-	12.744	53,484	2 23
Series 16	10/01/32	4 31600% *	96,000,000	4.143,360	72 708		186,036	4,402.104	4.59
Series 17	10/01/34	6.00000% *	50.000,000	3.000.000	40.068		53,940	3.094,008	6 19
Series 18	06/01/35	3.89000% *	13.266.950	516.084	17.700		-	533.784	4.02
Series 19	06/01/35	3 89000% *	13.266,950	516.084	17.988		-	534.072	4.03
Series 20	06/01/36	4 07400% *	16,693,620	680.098	20.688		-	700.786	4.20
Series 21	06/01/36	2 43000% *	16.693.620 2	405,655	-		20.774.64	426,430	2.55
Series 22	10/01/34	4 32000% *	54.000.000	2.332.800	37.343		-	2.370.143	4 39
CC 2007A $17.8M	02/01/26	5 75000% *	17 875.000	1.027.813	29.048		-	1.056,861	5.91
TC 2007A $8 9M	03/01/37	6 00000% *	8 927 000	535.620	12.957		-	548,577	6.15
Called Bonds			-	-	-	-	110,904 1	110,905	-
Total External Debt			332,753,140	14,720,034	277,072		457,311	15,454,418	1.22%
Notes Payable to Fidelia Corp	04/30/13	4 550%	100.000.000	4.550.000	-	-	-	4.550.000	4 55
Notes Payable to Fidelia Corp	08/15/13	5 310%	75,000,000	3.982 500	-	-	-	3.982.500	5.31
Notes Payable to Fidelia Corp	11/24/10	4 240%	33,000.000	1.399.200	-	-	-	1.399,200	4 24
Notes Payable to Fidelia Corp	01/16/12	4 390%	50.000.000	2.195,000	-	-	-	2.195.000	4.39
Notes Payable to Fidelia Corp	07/08/15	4 735%	50.000.000	2 367.500	-	-	-	2,367,500	4.74
Notes Payable to Fidelia Corp	12/21/15	5 360%	75.000.000	4.020.000	-	-	-	4,020,000	5.36
Notes Payable to Fidelia Corp.	06/23/36	6 330%	50.000.000	3.165,000	-	-	-	3.165,000	6 33
Notes Payable to Fidelia Corp.	10/25/16	5 675%	50.000.000	2.837.500	-	-	-	2.837,500	5.68
Notes Payable to Fidelia Corp.	02/07/22	5 690%	53,000.000	3.015.700	-	-	-	3,015.700	5 69
Notes Payable to Fidelia Corp.	03/30/37	5.860%	75.000 000	4.395.000	-	-	-	4.395,000	5 86
Notes Payable to Fidelia Corp.	06/20/17	5 980%	50.000 000	2.990.000	-	-	-	2.990.000	5.98
Notes Payable to Fidelia Corp	09/14/28	5 960%	100.000.000	5.960.000	-	-	-	5.960,000	5.96
Notes Payable to Fidelia Corp	10/25/19	5 710%	70.000.000	3 997 000	-	-	-	3.997.000	5.71
Notes Payable to Fidelia Corp	12/19/14	5 450%	100,000,000	5,450,000	-	-	-	5,450,000	5.45
Total Internal Debt			931,000,000	50,324,400	-	-	-	50,324,400	3.98%
		Total	1,263,753,140	65,044,434	277,072	0	457,311	65,778,818	5.21%

SHORT TERM DEBT

	Rate	Principal	Annualized Cost: Interest	Annualized Cost: Expense	Annualized Cost: Premium	Annualized Cost: Loss	Annualized Cost: Total	Embedded Cost
Notes Payable to Associated Company	2 630% *	93 302.454	2,453.855	-	-	-	2,453.855	2 63
Reacquired Bonds	2 630% *	(16,693,620) 2	(439,042)	-	-	-	(439,042)	2.63
	Total	76,608,834	2,014,813	-	-	-	2,014,813	2.63%

Embedded Cost of Total Debt	67.793,631	5.06%

* Composite rate at end of current month.

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

2 Reacquired bonds

KENTUCKY UTILITIES COMPANY
Common Equity Cash Flow
Test Year

	Total Common Equity Cash Flow
Dividends Received - 6/2007	5,350,000
Equity Contributions - 9/2007	55,000,000
Dividends Received - 9/2007	5,350,000
Dividends Received - 11/2007	5,350,000
Equity Contributions - 12/2007	20,000,000
Dividends Received - 2/2008	7,500,000
Total	$ 98,550,000

KENTUCKY UTILITIES CO
ELECTRONIC FUNDS TRANSFER SYSTEM
MONTHLY CASH RECEIPTS LEDGER
REPORT NO. CA2965A

RUN DATE: 6/29/07
RUN TIME: 22.34.06

IONTH OF: JUNE , 2007

)ATE OF ENTRY	BANK NUMBER	ADJ CODE	CODE NAME	ADJUSTMENT DESCRIPTION	ADJ AMOUNT
)6/15/07	00008	OR	OTHER RECEIPTS	AT&T INV#8007661 CK#100128426 DH	2,900.92
)6/15/07	00008	OR	OTHER RECEIPTS	CERADYNE INV#8007681 CK#59017 DH	31,920.29
)6/15/07	00008	OR	OTHER RECEIPTS	D WILDER NBRD7660H 1071944 1071944101 0675 DH	351.36
)6/15/07	00008	OR	OTHER RECEIPTS	SPO#438810-015110-PARKING-0670-015110 3CKS DH	30.00
)6/15/07	00008	OR	OTHER RECEIPTS	W CLARK RCST766 1005424 1005424101 0675 DH	18.00
)6/15/07	00008	OR	OTHER RECEIPTS	W CLARK RCST766 1085974 108594101 0675 DH	976.78
)6/15/07	00008	OR	OTHER RECEIPTS	LEE WEST LITTLE LEAGUE NBCD760H I 0428 DH	1,832.36
)6/15/07	00008	OR	OTHER RECEIPTS	CINGULAR 8007861 0699 006250 C#11471559 DH	4,196.74
)6/15/07	00008	OR	OTHER RECEIPTS	BAKER IRON 119961 UTILRELO 0675 015870 DH	20,746.44
)6/15/07	00008	OR	OTHER RECEIPTS	WILLIS NEAL RCST426 911216101 0675 014260 DH	828.05
)6/15/07	00008	OR	OTHER RECEIPTS	RIVER VIEW MINE K5 10840.RVCOAL 675 015870 DH	17,390.00
)6/20/07	00008	OR	OTHER RECEIPTS	RIVERVIEW COAL INV#8008121 CK#175000303 FAB	6,292.75
)6/20/07	00008	OR	OTHER RECEIPTS	WEBSTER CO BRD OF ED INV#8008321 CK#46046 FAB	1,588.25
)6/20/07	00008	OR	OTHER RECEIPTS	CHAD JESSUP INV#8008322 CK#2773 FAB	456.61
)6/20/07	00008	OR	OTHER RECEIPTS	KY DEPT OF REVENUE INV#106909 CK#11013389 FAB	420.59
)6/20/07	00008	OR	OTHER RECEIPTS	BPB MANUFACTURING INV#8008101 CK#19638 FAB	30,336.21
				BANK TOTAL	~~120,295.35~~
)6/21/07	00018	OR	OTHER RECEIPTS	WIRE 6/20/7 LNG TRM I/C LOAN FR FIDELIA TO KU	50,000,000.00
)6/21/07	00018	OR	OTHER RECEIPTS	EX INTEREST FRM US BNK DEFEASANCE $53MM BOND	696,032.13
				BANK TOTAL	~~50,696,032.13~~
)6/22/07	00003	OR	OTHER RECEIPTS	TVA INV #8008161-WIRED PYMT 6-20-07 FAB	38,287.15
				BANK TOTAL	~~38,287.15~~
)6/22/07	00008	OR	OTHER RECEIPTS	ALSTOM POWER INV#8008021 CK#252156 FAB	500.00
)6/22/07	00008	OR	OTHER RECEIPTS	EAST KY POWER INV#8008201 CK#118937 FAB	243,607.80
				BANK TOTAL	~~244,107.80~~
)6/25/07	00018	OR	OTHER RECEIPTS	0110.303.015450.015450.232001.000.0699.0000DH	14,379.74
)6/27/07	00018	OR	OTHER RECEIPTS	110.105.015590.015590.419200.0000.0699.0000DH	2,131.96
)6/28/07	00018	OR	OTHER RECEIPTS	110.301.015590.015590.171003.000.0699.0000DH	5,350,000.00
				BANK TOTAL	~~5,366,511.70~~
)6/29/07	00008	OR	OTHER RECEIPTS	WINDSTREAM INV#8008062 CK#74233 DH	995.76
)6/29/07	00008	OR	OTHER RECEIPTS	CUMBERLAND CELLULAR INV#8008341 CK#2679 DH	1,769.63
)6/29/07	00008	OR	OTHER RECEIPTS	BRADY JARVIS INV#8008365 CK#07 DH	224.18
)6/29/07	00008	OR	OTHER RECEIPTS	TRANSFORMER DECOM 113305 TR-B 0206 013010 DH	23,166.08
)6/29/07	00008	OR	OTHER RECEIPTS	U OF K 015110 REIMBURSEMENT 0620 015110 DH	24,513.00
)6/29/07	00008	OR	OTHER RECEIPTS	COMWLTH OF KY 122858 SALE 0427 015990 DH	16,000.00
)6/29/07	00008	OR	OTHER RECEIPTS	COMWLTH OF KY 122858 GATE 0427 015990 DH	450.00
)6/29/07	00008	OR	OTHER RECEIPTS	GEORGE FLYNN RDDD4260H M 0675 014260 DH	100.00
)6/29/07	00008	OR	OTHER RECEIPTS	CLOSE MNGR/FND PARIS OFF 8001246 699 15590 DH	300.00
)6/29/07	00008	OR	OTHER RECEIPTS	0110.105.015590.015590.456008.0000.0699. DH	5,149.40
)6/29/07	00008	OR	OTHER RECEIPTS	BIG RIVERS ELE CORP INV#8008181 CK#268530 DH	99.22
)6/29/07	00008	OR	OTHER RECEIPTS	KY DATA LINK INV#8008221 CK#2016575 DH	24,361.92
)6/29/07	00008	OR	OTHER RECEIPTS	C ENGLAND/STEALING RNTPD416 0 0321 014160 DH	97.88
)6/29/07	00008	OR	OTHER RECEIPTS	NEI GLOBAL REFUND 016220 BTL 0645 016220 DH	1,227.39

Gloria Booker

Bank of America

E.ON U.S. LLC

Previous Day All Data Summary and Detail with Text Report

	4,395,000.00	0000000000	00370122234	4,395,000.00	0.00	0.00

WIRE TYPE:WIRE IN DATE: 070627 TIME 1041 ET
TRN:2007062700122234 SEQ:0309100178ZO/002946
ORIG KENTUCKY UTILITIES SND BK:JPMORGAN CHASE BANK
NA ID:021000021 PMT DET:WRE OF 07/06/27 IHBCODE-
KUU-KUU

	202,500.00	0000000000	00370102148	202,500.00	0.00	0.00

WIRE TYPE:WIRE IN DATE: 070627 TIME:0940 ET
TRN:2007062700102148 SEQ:070627004267/000319
ORIG:KENTUCKY UTILITIES ID:000153910087961 SND BK:
U.S. BANK N.A. ID:123000848 PMT DET:070627004267 I
HBCODE KUU KUU

TOTAL	4,597,500.00	# of Items:	2	4,597,500.00

INCOMING INTERNL MONEY TRNSFR

	5,350,000.00	0000000000	00370115275	5,350,000.00	0.00	0.00

WIRE TYPE:BOOK IN DATE:070627 TIME:1041 ET
TRN:2007062700115275 SNDR REF:15508693
ORIG:ELECTRIC ENERGY INC ID:003750933741 PMT DET:2
ND QUARTER 2007 DIVIDENDS - ELECTRIC ENERGY INC.
KENTUCKY UTILITIES COMPANY

TOTAL	5,350,000.00	# of Items:	1	5,350,000.00

TOTAL CREDITS

	9,947,500.00	# of Items	3	9,947,500.00

Detail Debits

	Amount	Customer Reference	Bank Reference	Immediate Availability	1 Day Float	2+ Day Float

0110.301.015590.015590.171003.0000.0699.0180 YD

PREAUTHORIZED ACH DEBIT

	48,939.05	0000000000	00250015698

KENTUCKY UTILITI;DES=CCD ;ID=FL# 20071770739
EFF DATE: 070627;INDN:KUCOMPAN4

TOTAL	48,939.05	# of Items:	1

OUTGOING INTERNL MONEY TRNSFR

	3,182,000.00	0000000000	00370131872

WIRE TYPE:BOOK OUT DATE:070627 TIME:1113 ET
TRN:2007062700131872 RELATED REF:15509501
BNF:E.ON U.S. LLC ID:003752102075 PMT DET:IHBCODE-
KUU-UTP

JUN 28 2007

TOTAL	3,182,000.00	# of Items:	1

DEP+ TRANSFER DEBIT

	1,370,262.63	0000000000	00722000405

CUR TO 3299027583

	7.51	0000000000	00722000407

CUR TO 3299027591

TOTAL	1,370,270.14	# of Items	2

Henley, Deena Quarterly-E.E.I pymts

To: Schmidt, Sandy
Subject: RE EEI glaff

-----Original Message-----
From: Schmidt, Sandy
Sent: Thursday, March 29, 2007 9:36 AM
To: Henley, Deena
Subject: EEI glaff

Deena,
Please charge the EEI to the following account: ELECTRIC ENERGY INC. QUARTERLY PYMTS

0110.0301.015590.015590.171003.0000.0699.0000 No Project/No Task will be associated with it.
Thanks.

Sandy Schmidt
E.ON U.S
Financial Reporting
502-627-2682 office
502-217-2766 fax

Newton, Gretchen

From:	Kelly. Mimi
Sent:	Friday, August 24, 2007 4:19 PM
To:	Harris, Donald
Cc:	Scott, Valerie; Lovekamp, Rick; Newton, Gretchen; Dickson, Gloria
Subject:	FW: E.ON Merger Commitment No 26
Attachments:	KPSC Filing Letter for Equity Contribution 2007-09 KU (Revised-2).doc

Don -
My "old" group - Financial Accounting & Reporting will make the journal entry. Do you just need a copy or something more formal?

From:	Harris, Donald
Sent:	Friday, August 24, 2007 2:10 PM
To:	Kelly, Mimi
Cc:	Scott, Valerie; Lovekamp, Rick
Subject:	E.ON Merger Commitment No. 26

Mimi,

Today we filed with the KPSC the attached letter. Per the E ON Order, the KPSC requires the following:

"E ON, PowerGen, LG&E Energy, LG&E, and KU commit to notifying the Commission 30 days prior to making any capital contribution to LG&E or KU and to provide the accounting entries reflecting the capital contribution within 60 days after the close of the month in which the contribution was made."

When the accounting entries are made. I will need to file the information with the KPSC In speaking with Valerie Scott, and in terms of the accounting entries, would this fall under your old role or current role?
Thanks.

KPSC Filing Letter for Equity ...

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

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602-0615

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

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

August 24, 2007

Re: ***E.ON AG, E.ON U.K. LTD (formerly Powergen LTD), E.ON U.S. LLC (formerly LG&E Energy LLC), Louisville Gas and Electric Company, and Kentucky Utilities Company* - Case No. 2001-104**

Dear Ms. O'Donnell:

Pursuant to the Commission's Order in the aforementioned case, Kentucky Utilities Company ("KU") hereby notifies the Commission that E.ON U.S. LLC is planning to contribute approximately $55 million of additional paid in capital on or about September 24, 2007. As noted in the CCN applications, Case No 2004-00507[1], Case No 2005-00142[2], and Case No 2004-00426[3], KU's significant capital expenditure program would require equity contributions from E.ON U.S. LLC to maintain a balanced capital structure. This contribution represents the first installment of such contributions.

This information is submitted in response to the filing requirements contained within the aforementioned order specifically, Appendix A Reporting Item Nos. 25 and 26 in Case No. 2001-104, dated August 6, 2001.

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[1] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate for the Expansion of the Trimble County Generating Station*, filed December 17, 2004

[2] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade and Hardin Counties, Kentucky*, filed May 11, 2005

[3] *The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of its 2004 Compliance Plan for Recovery by Environmental Surcharge*, filed December 20, 2004

Ms Elizabeth O'Donnell
August 24, 2007

Please confirm your receipt of this filing by placing the stamp of your Office with date received on the extra copy and returning to me in the enclosed envelope Should you have any questions regarding this information, please contact me or Don Harris at 502-627-2021

Sincerely,

Rick E Lovekamp

cc: Daniel K Arbough. E ON U.S. Services, Inc.
Kendrick Riggs – Stoll Keenon Ogden

Bank of America
E.ON U.S. LLC
Previous Day All Data Summary and Detail with Text Report

CASH LETTER PRE-ENCODED DEP CR

	853,779 78	0000000000	00722183205	2,427 24	790,593 62	60,758 92
	CUR FR 4426403300					
	252,750 51	0000000000	00722183204	485 06	234,434.84	17,830 61
	CUR FR 4426403300					
	6,827.89	0000000000	00722183203	0 00	6,327 99	499.90
	CUR FR 4426403300					
TOTAL	1,113,358.18	# of Items:	3	2,912.30	1,031,356 45	79,089.43

INCOMING MONEY TRANSFER CREDIT

	1,490,000.00	0000000000	00370136345	1,490,000.00	0.00	0 00
	WIRE TYPE:WIRE IN DATE: 070925 TIME:1144 ET TRN:2007092500136345 SEQ:0497200268ZO/002696 ORIG:KENTUCKY UTILITIES SND BK:JPMORGAN CHASE BANK NA ID:021000021 PMT DET:WRE OF 07/09/25 IHBCODE- KUU-KUU					
	908,000 00	0000000000	00370135195	908.000.00	0 00	0.00
	WIRE TYPE:WIRE IN DATE: 070925 TIME:1141 ET TRN:2007092500135195 SEQ:070925012031/001337 ORIG:KENTUCKY UTILITIES ID:000153910087981 SND BK: U.S BANK N.A. ID:123000848 PMT DET:070925012031 I HBCODE KUU KUU					
TOTAL	2,398,000.00	# of Items:	2	2,398,000.00		

INCOMING INTERNL MONEY TRNSFR

	55,000,000 00	0000000000	00370116653	55,000,000 00 p.2	0.00	0.00
	WIRE TYPE:BOOK IN DATE:070925 TIME:1038 ET TRN:2007092500116653 SNDR REF:807650027 ORIG:E.ON U.S. SERVICES INC.					
TOTAL	55,000,000 00	# of Items:	1	55,000,000.00		

CREDIT ADJUSTMENT

	333.93	0000000000	00722183207	333 93	0 00	0 00
	CUR FR 4426403300 7687100751 V4 CR BK ADJUSTMENT					
TOTAL	333.93	# of Items:	1	333.93		

INDIVIDUAL ACH RETURN ITEM CR

	517 96	0000000000	68009918372	517 96	0.00	0.00
	KY UTILITIES DES:RETURN ID: INDN:SETT-ACH DETAIL RETURN CO ID:2610247570 CCD					
TOTAL	517.96	# of Items:	1	517.96		
TOTAL CREDITS						
	58,512,763.64	# of Items:	9	57,402,317.76	1,031,356.45	79,089 43

Detail Debits

Amount	Customer Reference	Bank Reference	Immediate Availability	1 Day Float	2+ Day Float

4.

MONTH OF: SEPTEMBER, 2007

DATE OF ENTRY	BANK NUMBER	ADJ CODE	CODE NAME	ADJUSTMENT DESCRIPTION	ADJ AMOUNT
					~~56,000,000.00~~
				BANK TOTAL	
09/26/07	02312	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.07
09/26/07	02312	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.01-
				BANK TOTAL	~~0.06~~
09/26/07	02417	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	1.50
				BANK TOTAL	~~1.50~~
09/26/07	03119	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	3.03
				BANK TOTAL	~~3.03~~
09/26/07	03411	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.74-
				BANK TOTAL	~~0.74-~~
09/26/07	03422	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.20-
				BANK TOTAL	~~0.20-~~
09/26/07	03513	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.01
				BANK TOTAL	~~0.01~~
09/26/07	03852	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.04-
				BANK TOTAL	~~0.04-~~
09/26/07	04412	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.20
				BANK TOTAL	~~0.20~~
09/26/07	07512	OR	OTHER RECEIPTS	W/O DIFF IN DEPOSIT - SKS	0.60-
				BANK TOTAL	~~0.60-~~
				110.0703.015590.015590.131092.0000.0699.0000	
09/27/07	00015	OR	OTHER RECEIPTS	110.0301.015590.015590.171003.0000.699.00000H	5,350,000.00
				BANK TOTAL	~~5,350,000.00~~
09/27/07	03119	OR	OTHER RECEIPTS	KY DATA LINK DTS#2018484 CK#2018484	2,103.70
09/27/07	03119	OR	OTHER RECEIPTS	ROCKCATLE CABLEVISION INV#8008613 C#1501 DH	331.98
09/27/07	03119	OR	OTHER RECEIPTS	IBEW LOCAL 2100 INV#8009021 CK#4642 DH	3,369.57
09/27/07	03119	OR	OTHER RECEIPTS	SUDDENLIK COM INV#8009261 CK#77784 DH	1,821.02
09/27/07	03119	OR	OTHER RECEIPTS	EAST KY POWER INV#8009341 CK#122035 DH	203,299.95
09/27/07	03119	OR	OTHER RECEIPTS	GEO FLYNN RD004260H I 0675 014260 DH	100.00
09/27/07	03119	OR	OTHER RECEIPTS	JOHN DOE MNGR FUND INV#8001202 0699 015990 DH	450.00
09/27/07	03119	OR	OTHER RECEIPTS	DAVID COZZOLINA RD007608G 1175624 0675 DH	521.99
09/28/07	03119	OR	OTHER RECEIPTS	CWS SPECIAL 104584 5657 0677 CK#261543 DH	777.94
					213,256.15

AR
Misc
3.14

Jolo-096-8009
6 Dickson

Clerk

2

Electric Energy, Inc.
Statement Of Retained Earnings
For The Month Ended July 31, 2007

		This Month		Year To Date
Balance at Beginning of Period	$	91,140,554	$	80,534,431
Dividends		(26,750,000)		(80,250,000)
Net Income		10,479,852		74,585,975
Balance at End of Period	$	74,870,406	$	74,870,406

X.2 5,350,000 p.2

Schmidt, Sandy

To: Henley, Deena

Subject: FW: EEI 4th quarter dividend payment to Kentucky Utilities Company

Something to watch for. I think you have the numbers for this, if not, give me a shout.

From: Janet Nennstiel [mailto:janetnennstiel@electricenergyinc.com]
Sent: Monday, December 10, 2007 5:08 PM
To: Dickson, Gloria
Cc: Schmidt, Sandy; Jim Helm
Subject: EEI 4th quarter dividend payment to Kentucky Utilities Company

Hi Gloria, I just wanted to confirm with you that I should use the same wiring instructions I've previously used when I wire Kentucky Utilities $5,350,000 4th Quarter Dividend payment on Wednesday, December 26:

Bank of America
Dallas, TX
ABA: 026009593
Account: 3752099120
Account Name: Kentucky Utilities Company

If this information is not correct, then please let me know Thank you Janet

Janet L. Nennstiel, CPA
Accounting Services
Electric Energy, Inc
(618) 543-7531 ext 609

KENTUCKY UTILITIES CO
ELECTRONIC FUNDS TRANSFER SYSTEM
MONTHLY CASH RECEIPTS LEDGER
REPORT NO. CA2965A

ONTH OF: DECEMBER , 2007

RUN DATE: 12/31/07
RUN TIME: 23.26.37

ATE OF ENTRY	BANK NUMBER	ADJ CODE	CODE NAME	ADJUSTMENT DESCRIPTION	ADJ AMOUNT
					~~2.29~~
				BANK TOTAL	
2/21/07	03712	OR	OTHER RECEIPTS	DIFF IN DEPOSIT - SKS	0.01
					~~0.01~~
				BANK TOTAL	
2/21/07	03852	OR	OTHER RECEIPTS	DIFF IN DEPOSIT - SKS	3.26-
					~~3.26-~~
				BANK TOTAL	
2/21/07	04212	OR	OTHER RECEIPTS	DIFF IN DEPOSIT - SKS	0.70-
					~~0.70-~~
				BANK TOTAL	
2/27/07	00018	OR	OTHER RECEIPTS	110.0301.015590.015590.171003.0000.699.0000DH	✓5,350,000.00✓
					~~5,350,000.00~~
				BANK TOTAL	
2/28/07	03119	OR	OTHER RECEIPTS	ALSTOM POWER INV#8009924 CK#256858 DH	500.00 CJ
2/28/07	03119	OR	OTHER RECEIPTS	ALSTOM POWER 120603 5425410 0677 CK#537689 DH	✓9,293.37✓
2/28/07	03119	OR	OTHER RECEIPTS	LASRENCE CONST 123369 108901 0677 C#6922 DH	✓20,000.00✓
2/28/07	03119	OR	OTHER RECEIPTS	YOUNGBLOOD CNST 119844 4992814 0677 C#18911DH	✓35,000.00✓
2/28/07	03119	OR	OTHER RECEIPTS	TRNSFMER DCM 121888 JUNKEQUIPE 0206 015740 DH	✓989.40✓
2/28/07	03119	OR	OTHER RECEIPTS	TRNSFMER DCM 121888 JUNKEQUIPE 0206 015740 DH	✓2,385.00✓
2/28/07	03119	OR	OTHER RECEIPTS	JIM HAMILTON 114128 10840-T6676 0675 003070DH	✓10,000.00✓
2/28/07	03119	OR	OTHER RECEIPTS	LEXTRAN 123597 LEXTRAN 0632 015590 C#11022 DH	✓950.00✓
2/28/07	03119	OR	OTHER RECEIPTS	GEN AMER MUTUAL 105132 VEMUTUAL 0699 015590DH	✓207,226.09✓
2/28/07	03119	OR	OTHER RECEIPTS	0110.105.015590.015590.421001.0000.0699 DH	✓6,342.79✓
2/28/07	03119	OR	OTHER RECEIPTS	EAST KY POWER INV#8010141 CK#125346 DH	130,436.67 CJ
2/28/07	03119	OR	OTHER RECEIPTS	WINDSTREAM INV#8009961 CK#104965 DH	7,513.71 CJ
2/28/07	03119	OR	OTHER RECEIPTS	CARGILL POWER INV#8010143 CK#301368132 DH	90.90 CJ
2/28/07	03119	OR	OTHER RECEIPTS	HARLAN CUMBERLAND COAL INV#8010222 C#149000DH	136.00 CJ
2/28/07	03119	OR	OTHER RECEIPTS	DANVILLE IND SCHOOL INV#8010223 CK#43217 DH	396.00 CJ
2/28/07	03119	OR	OTHER RECEIPTS	STAMLER CORP INV#8010224 C#171482 DH	48.00 CJ
2/28/07	03119	OR	OTHER RECEIPTS	BIG RIVER ELEC INV#8010142 CK#270024 DH	144.21 CJ
2/28/07	03119	OR	OTHER RECEIPTS	CENTRE COLLEGE INV#8010081 CK#132517 DH	2,322.33 CJ
2/28/07	03119	OR	OTHER RECEIPTS	#438810-015100-PARKING-0670-015110 2 CKS DH	✓170.00✓
2/28/07	03119	OR	OTHER RECEIPTS	#438810-015110-PARKING-0670-015110 5 CKS DH	✓70.00✓
2/28/07	03119	OR	OTHER RECEIPTS	ODP RCST766 129877S101 0281 CK#301797 DH	✓42,586.73✓
2/28/07	03119	OR	OTHER RECEIPTS	FLATWOODS RDDD7660H M 0675 CK#7124 DH	✓100.00✓
2/28/07	03119	OR	OTHER RECEIPTS	W CLARK RCST766 1193136 1193136R02 0675 DH	✓805.32✓
					~~477,506.52~~
				BANK TOTAL	
2/31/07	00018	OR	OTHER RECEIPTS	TVA INV#8010144 12/31 WIRED PYMT DH	40,375.03 CJ
2/31/07	00018	OR	OTHER RECEIPTS	110.105.015590.015590.419205.0000.0699.0000DH	✓2,907.05✓
					~~43,282.08~~
				BANK TOTAL	
					118,450,660.41 (A)
				CODE TOTAL	
~~2/03/07~~	~~00003~~	~~TI~~	~~TRANSFERS IN~~	~~CASH CONCENTRATION~~	~~593,648.38~~

Misc SKS

Bank of America
E.ON U.S. LLC
WIRES IN -- KU

As of 12/21/2007
Bank of America Accounts

Bank of America, Customer Connection ABA: 111000012, US Dollar (USD) Accounts

3752099120 Kentucky Utilities Funding — Last Updated: 12 21 2007 11:51 CST

Detail Credits

	Amount	Customer Reference	Bank Reference	Immediate Availability	1 Day Float	2+ Day Float
INCOMING INTERNL MONEY TRNSFR						
	20,000,000.00	1221160774	071221160774	20,000,000.00	0.00	0.00

WIRE TYPE:BOOK IN DATE:122107 TIME:1131 ET
TRN:2007122100160774 SNDR REF:807850042
SERVICE REF:
RELATED REF:
ORIG:E ON U S SERVICES INC 220 W MAIN STREET LOUISVILLE
KY 40202 USA ID:
ORG BK: ID
INS BK:ECS-ELECTRONIC COMMERCE SYST ID:ECSA
SND BK: ID:
BNF:KENTUCKY UTILITIES COMPANY ATTN: FINANCIAL
ACCTNG&REPORTING 220 WEST MAIN STREET 9TH FLOOR LOUISVILLE
KY 40202 ID:003752099120
BNF BK: ID
PAYMENT DETAILS

Equity Contribution

TOTAL	20,000,000.00	# of Items	1	20,000,000.00

TOTAL CREDITS

	20,000,000.00	# of Items:	1	20,000,000.00

TOTAL Bank of America, Customer Connection ABA: 111000012 — ***US Dollar (USD)***

Description	Amount	# of Items	Immediate Availability	1 Day Float	2+ Day Float
TOTAL CREDITS					
	20,000,000.00	1	20,000,000.00		
TOTAL DEBITS					
	0.00				

TOTAL US Dollar (USD) Accounts as of 12/21/2007

Description	Amount	# of Items	Immediate Availability	1 Day Float	2+ Day Float
TOTAL CREDITS					
	20,000,000.00	1	20,000,000.00		
TOTAL DEBITS					
	0.00				

DISBURSEMENT REQUEST

(Corporate Policy & Procedures are on Intranet)

Ixc Karen Callahan
Ixc Sandy Schmidt

Specify Company:
XX E ON U.S. LLC

SUPPLIER NAME. Kentucky Utilities
REMITTANCE ADDRESS. Bank of America
ABA 026009593
Account #3752099170

DUE DATE 12/21/2007

SPECIAL INSTRUCTIONS: **WIRE FUNDS**

ACCOUNTING DISTRIBUTION				
PROJECT	TASK	EXP TYPE	EXP ORG	AMOUNT
LEC0800	CAP CONTR KU	00699	000800	$20,000,000.00
			TOTAL	$20,000,000.00

PREPARER SIGNATURE.		DATE: 12-11-07
APPROVER SIGNATURE		DATE: 12-11-07
APPROVER TITLE.	Treasurer	
APPROVER SIGNATURE		DATE: 12/13/07
APPROVER TITLE	CFO	

REASON FOR EXPENDITURE
Equity Contribution from EUS to KU

Form SD 71 A
Rev. 9/98

S:\CASH MANAGEMENT\2007\DAILY CASH\Disbursement Request Equity Contrib EUS to KU_LGE xls

Wiedmar, John

From: Arbough, Dan
Sent: Tuesday, December 11, 2007 12:45 PM
To: Wiedmar, John
Subject: RE Equity Contributions - 12-21-07
Signed By: dan.arbough@eon-us com

$20 million to each of KU and LG&E is correct

Dan

From: Wiedmar, John
Sent: Tuesday, December 11, 2007 12:20 PM
To: Arbough, Dan
Subject: Equity Contributions - 12-21-07

Dan,

For supporting documentation to the disbursement request we are preparing, please confirm that we need to make equity contributions from E.ON U.S of $20 million to LG&E and $20 million to KU

Thanks

EQUITY CONTRIBUTIONS TO LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

WHEREAS, the Company is the sole shareholder of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") and deems it advisable and in the best interests of the Company, LG&E and KU that it contribute up to approximately $20 million and $155 million as equity to LG&E and KU, respectively, in connection with the capital, financial or operating needs of LG&E and KU during 2007 (the "Contributions")

NOW, THEREFORE, BE IT RESOLVED, that the Board of Directors hereby authorizes the Contributions, which contributions may be made in the amounts and at the times determined by appropriate officers of the Company consistent with these resolutions and may be in such forms as determined by the officers of the Company, consistent with sound business practice; and

FURTHER RESOLVED, that the appropriate officers be, and each of them hereby is, authorized in the name and on behalf of the Company and under its seal or otherwise, to take or cause to be taken all such actions and to execute and deliver or cause to be executed and delivered all such documents, certificates and agreements as such officers may deem necessary, advisable or appropriate in connection with the Contributions and the transactions contemplated hereby, and to incur all such fees and expenses as shall be necessary, advisable or appropriate in their judgment in order the carry into effect the purpose and intent of any and all of the foregoing resolutions; and

FURTHER RESOLVED, that any acts of the officers of this Company and of any person or persons designated and authorized to so act by an officer of this Company, which acts would have been authorized by the foregoing resolutions except that such acts were taken prior to the adoption of such resolutions, are hereby severally ratified, confirmed, approved and adopted as acts in the name of and on behalf of this Company.

PENSION PLAN CONTRIBUTIONS

WHEREAS, the Company, LG&E and KU propose to make up to approximately $112 million in contributions to pension plans relating to employees of the Company or its subsidiaries during 2007, in the following approximate amounts respectively: the Company $43 million; LG&E $56 million and KU $13 million (collectively, the "Pension Contributions"), and

WHEREAS, the Pension Contributions may take the form of cash, notes, securities or other assets and will increase the funding status of the various pension plans to levels which promote certain actuarial, legal, regulatory and tax

WITNESS the signatures of the undersigned who are all of the directors of E ON U S LLC as of the date first written above

Victor A. Staffieri

Chris Hermann

John R. McCall

S. Bradford Rives

Paul W. Thompson

ELECTRONIC FUNDS TRANSFER SYSTEM
MONTHLY CASH RECEIPTS LEDGER
REPORT NO. CA2965A

ITH OF: MARCH , 2008

RUN DATE: 3/31/08
RUN TIME: 23.18.10

E OF ITRY	BANK NUMBER	ADJ CODE	CODE NAME	ADJUSTMENT DESCRIPTION	ADJ AMOUNT
11/08	00018	CR	OTHER RECEIPTS	BAKER IRON JNK#216 CC108901 0206 012160 DH	2,110.26
11/08	00018	CR	OTHER RECEIPTS	BAKER IRON JNK#766 CC108901 0206 017660 DH	6,933.66
20/08	00018	CR	OTHER RECEIPTS	110.105.015590.015590.419205.0000.0699.0000DH	2,522.97
				BANK TOTAL	~~45,524.82~~
20/08	00020	CR	OTHER RECEIPTS	CUMBERLAND CELLULAR INV#8010967 CC 3/8 OR DH	1,769.63 CJ
				BANK TOTAL	~~1,767.63~~
20/08	03119	CR	OTHER RECEIPTS	SUBRO 109345 V 0699 013150 DH	1,726.78
20/08	03119	CR	OTHER RECEIPTS	BAKER IRON 121076 10701.T035 0675 015870 DH	3,430.89
20/08	03119	CR	OTHER RECEIPTS	SUNTRUST X00002593 REBATE 0414 015930 DH	553.75
20/08	03119	CR	OTHER RECEIPTS	SUNTRUST X00002593 REBATE 0417 015930 DH	620.67
20/08	03119	CR	OTHER RECEIPTS	SOLOMON 123122 JUNKEQUIPL 0303 015740 DH	52,674.40
20/08	03119	CR	OTHER RECEIPTS	SOLOMON 123122 JUNKEQUIPD 0303 015740 DH	1,956.00
20/08	03119	CR	OTHER RECEIPTS	ISA RECYCLING 104584 5657 0677 C#129234 DH	834.19
20/08	03119	CR	OTHER RECEIPTS	DOMINION RCST766 1421957I01 0675 C#310386 DH	1,236.43
20/08	03119	CR	OTHER RECEIPTS	DOMINION RCST766 1324274I01 0301 C#310632 DH	132,291.58 — 41,732.77 + 90,558.81
20/08	03119	CR	OTHER RECEIPTS	S CENTRAL RTC OH REFUNDABLE ADVANCE AGRMNT DH	2,260.45
20/08	03119	CR	OTHER RECEIPTS	453080-015110-PARKING-0670-015110 10 CKS DH	118.50
20/08	03119	OR	OTHER RECEIPTS	OVERAGE NBRD2560H 12560 0667 012560 CASH DH	8.00
20/08	03119	OR	OTHER RECEIPTS	LL COMM INV#8010942 CK#17024 DH	137.76 CJ
20/08	03119	CR	OTHER RECEIPTS	GGD CO INV#8011162 CK#164037 DH	1,840.09 CJ
20/08	03119	CR	OTHER RECEIPTS	COMCAST INV#8011121 CK#279894929 DH	5,944.39 CJ
20/08	03119	CR	OTHER RECEIPTS	COMCAST INV#8011141 CK#279894929 DH	12,681.46 CJ
20/08	03119	CR	OTHER RECEIPTS	ARMSTRONG COAL INV#8011482 CK#2552 DH	7,143.79 CJ
20/08	03119	CR	OTHER RECEIPTS	WILCOP CABLE INV#8010966 CK#10868 DH	715.45 CJ
20/08	03119	CR	OTHER RECEIPTS	SCD/DJI JOINT INV#8011546 CK#220358 DH	13,412.61 CJ
20/08	03119	CR	OTHER RECEIPTS	GATES NISSAN INV#8011485 CK#1393 DH	1,178.00 CJ
20/08	03119	CR	OTHER RECEIPTS	IRVINE COMM TV INV#8010964 CK#35744 DH	1,287.25 CJ
20/08	03119	CR	OTHER RECEIPTS	LL COMM INV#8011001 CK#17024 DH	229.00 CJ
20/08	03119	CR	OTHER RECEIPTS	FRANKFORT ELEC INV#8011181 CK#36504 DH	1,126.01 CJ
20/08	03119	CR	OTHER RECEIPTS	HORIZON COMM INV#8011461 CK#1086 DH	188.35 CJ
20/08	03119	CR	OTHER RECEIPTS	HARLAN COMM TV INV#8010946 CK#25659 DH	1,647.68 CJ
20/08	03119	CR	OTHER RECEIPTS	CITY OF BARDSTOWN INV#8011361 CK#83C45 DH	192,615.00 CJ
20/08	03119	CR	OTHER RECEIPTS	BIG RIVERS INV#8009861 CK#270623 DH	259.62 CJ
20/08	03119	CR	OTHER RECEIPTS	AT&T 8010722 0699 006250 CK#12414902 DH	4,415.08 CJ — ?
20/08	03119	CR	OTHER RECEIPTS	LEXTRAN 123597 LEXTRAN2 0632 015590 DH	950.00
20/08	03119	CR	OTHER RECEIPTS	DOMINION V POWER 123770 I 0675 017660 DH	100,000.00
20/08	03119	CR	OTHER RECEIPTS	SUBRO 109345 V 0699 013150 DH	1,399.73
20/08	03119	CR	OTHER RECEIPTS	SUBRO 109345 V 0699 012460 DH	23,813.84
				BANK TOTAL	~~608,698.95~~
25/08	00018	CR	OTHER RECEIPTS	TVA INV#8011501 3/20 WIRE SHEET DH	55,371.35 CJ
25/08	00018	CR	OTHER RECEIPTS	110.303.015450.015450.232001.0000.0699.0000DH	4,074.69
27/08	00018	CR	OTHER RECEIPTS	110.301.015590.015590.171003.0000.0699.0000DH	7,500,000.00
				BANK TOTAL	~~7,559,446.04~~
27/08	03119	CR	OTHER RECEIPTS	TIME WARNER INV#8011021 CK#2155897 DH	6,024.35 CJ

Henley, Deena Quarterly - EEI pymt.

To: Schmidt, Sandy
Subject: RE: EEI glaff

-----Original Message-----
From: Schmidt, Sandy
Sent: Thursday, March 29, 2007 9:36 AM
To: Henley, Deena
Subject: EEI glaff

Deena,
Please charge the EEI to the following account: ELECTRIC ENERGY INC. QUARTERLY PYMTS

0110.0301.015590.015590.171003 0000.0699.0000 No Project/No Task will be associated with it.
Thanks.

Sandy Schmidt
E.ON U.S.
Financial Reporting
502-627-2682 office
502-217-2766 fax

Bank of America
E.ON U.S. LLC
Previous Day Detail with Text Report

18,064,000.00	0000000000	00370171298	18,064,000.00	0.00	0.00
	WIRE TYPE:BOOK IN DATE:080326 TIME:1304 ET TRN 2008032600171298 SNDR REF:19331817 ORIG:E ON U S LLC ID:003752102075 PMT DET:IHBCODE -UTP-KUU				
7,500,000.00	0000000000	00370117930	7,500,000.00	0.00	0.00
	WIRE TYPE:BOOK IN DATE:080326 TIME:1022 ET TRN 2008032600117930 SNDR REF:19325425 ORIG:ELECTRIC ENERGY INC ID:003750933741 PMT DET 1 ST QUARTER 2008 DIVIDENDS - ELECTRIC ENERGY INC KENTUCKY UTILITIES COMPANY				
TOTAL 25,564,000.00	# of Items:	2	25,564,000.00		
TOTAL CREDITS					
30,627,730.99	# of Items:	19	27,989,185.58	2,010,612.79	627,932.62

OK
MAR 27 2008

KENTUCKY UTILITIES COMPANY
Short-Term Debt
Test Year

	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08
Money Pool Investments												
Beg Balance	$ 62,745,054	$ 127,047,054	$ 140,309,054	$ 191,360,054	$ 256,044,054	$ 105,303,054	$ 51,345,054	$ 116,692,054	$ 23,219,454	$ 59,036,454	$ 48,000,454	$ 50,063,454
Borrowings	$ 117,252,000	$ 121,692,000	$ 106,005,000	$ 128,468,000	$ 77,828,000	$ 96,406,000	$ 121,422,000	$ 51,903,000	$ 115,396,000	$ 78,612,000	$ 97,201,000	$ 117,728,000
Repayments	$ (52,950,000)	$ (108,430,000)	$ (54,954,000)	$ (63,784,000)	$ (228,569,000)	$ (150,364,000)	$ (56,075,000)	$ (145,375,600)	$ (79,579,000)	$ (89,648,000)	$ (95,138,000)	$ (74,489,000)
Ending Balance	$ 127,047,054	$ 140,309,054	$ 191,360,054	$ 256,044,054	$ 105,303,054	$ 51,345,054	$ 116,692,054	$ 23,219,454	$ 59,036,454	$ 48,000,454	$ 50,063,454	$ 93,302,454

Total Borrowings	$ 1,229,913,000
Total Repayments	$ (1,199,355,600)

Money Pool Statements - May 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($62,745,054.00)		
05/01/07		2,200,000.00	($60,545,054.00)	5.2600%	($8,846.31)
05/02/07		2,950,000.00	($57,595,054.00)	5.2600%	($8,415.28)
05/03/07		2,480,000.00	($55,115,054.00)	5.2600%	($8,052.92)
05/04/07		3,125,000.00	($51,990,054.00)	5.2600%	($7,596.32)
05/05/07			($51,990,054.00)	5.2600%	($7,596.32)
05/06/07			($51,990,054.00)	5.2600%	($7,596.32)
05/07/07	11,580,000.00		($63,570,054.00)	5.2600%	($9,288.29)
05/08/07		5,215,000.00	($58,355,054.00)	5.2600%	($8,526.32)
05/09/07		3,025,000.00	($55,330,054.00)	5.2600%	($8,084.34)
05/10/07		3,360,000.00	($51,970,054.00)	5.2600%	($7,593.40)
05/11/07		2,890,000.00	($49,080,054.00)	5.2600%	($7,171.14)
05/12/07			($49,080,054.00)	5.2600%	($7,171.14)
05/13/07			($49,080,054.00)	5.2600%	($7,171.14)
05/14/07		3,825,000.00	($45,255,054.00)	5.2600%	($6,612.27)
05/15/07		2,775,000.00	($42,480,054.00)	5.2600%	($6,206.81)
05/16/07		4,035,000.00	($38,445,054.00)	5.2600%	($5,617.25)
05/17/07	93,655,000.00		($132,100,054.00)	5.2600%	($19,301.29)
05/18/07		5,145,000.00	($126,955,054.00)	5.2600%	($18,549.54)
05/19/07			($126,955,054.00)	5.2600%	($18,549.54)
05/20/07			($126,955,054.00)	5.2600%	($18,549.54)
05/21/07		950,000.00	($126,005,054.00)	5.2600%	($18,410.74)
05/22/07	8,030,000.00		($134,035,054.00)	5.2600%	($19,584.01)
05/23/07		1,750,000.00	($132,285,054.00)	5.2600%	($19,328.32)
05/24/07	3,027,000.00		($135,312,054.00)	5.2600%	($19,770.59)
05/25/07	960,000.00		($136,272,054.00)	5.2600%	($19,910.86)
05/26/07			($136,272,054.00)	5.2600%	($19,910.86)
05/27/07			($136,272,054.00)	5.2600%	($19,910.86)
05/28/07			($136,272,054.00)	5.2600%	($19,910.86)
05/29/07		1,485,000.00	($134,787,054.00)	5.2600%	($19,693.89)
05/30/07		4,520,000.00	($130,267,054.00)	5.2600%	($19,033.46)
05/31/07		3,220,000.00	($127,047,054.00)	5.2600%	($18,562.99)
	117,252,000.00	**52,950,000.00**		**5.2600%**	**(410,522.92)**

Money Pool Statements - June 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($127,047,054.00)		
06/01/07	530,000.00		($127,577,054.00)	5.2600%	($18,640.43)
06/02/07			($127,577,054.00)	5.2600%	($18,640.43)
06/03/07			($127,577,054.00)	5.2600%	($18,640.43)
06/04/07	16,440,000.00		($144,017,054.00)	5.2600%	($21,042.49)
06/05/07		3,990,000.00	($140,027,054.00)	5.2600%	($20,459.51)
06/06/07		3,500,000.00	($136,527,054.00)	5.2600%	($19,948.12)
06/07/07		6,800,000.00	($129,727,054.00)	5.2600%	($18,954.56)
06/08/07		3,085,000.00	($126,642,054.00)	5.2600%	($18,503.81)
06/09/07			($126,642,054.00)	5.2600%	($18,503.81)
06/10/07			($126,642,054.00)	5.2600%	($18,503.81)
06/11/07		4,230,000.00	($122,412,054.00)	5.2600%	($17,885.76)
06/12/07		6,265,000.00	($116,147,054.00)	5.2600%	($16,970.38)
06/13/07		5,410,000.00	($110,737,054.00)	5.2600%	($16,179.91)
06/14/07		3,342,000.00	($107,395,054.00)	5.2600%	($15,691.61)
06/15/07		1,874,000.00	($105,521,054.00)	5.2600%	($15,417.80)
06/16/07			($105,521,054.00)	5.2600%	($15,417.80)
06/17/07			($105,521,054.00)	5.2600%	($15,417.80)
06/18/07	9,710,000.00		($115,231,054.00)	5.2600%	($16,836.54)
06/19/07	63,130,000.00		($178,361,054.00)	5.2600%	($26,060.53)
06/20/07		51,548,000.00	($126,813,054.00)	5.2600%	($18,528.80)
06/21/07		7,021,000.00	($119,792,054.00)	5.2600%	($17,502.95)
06/22/07		3,270,000.00	($116,522,054.00)	5.2600%	($17,025.17)
06/23/07			($116,522,054.00)	5.2600%	($17,025.17)
06/24/07			($116,522,054.00)	5.2600%	($17,025.17)
06/25/07	22,647,000.00		($139,169,054.00)	5.2600%	($20,334.15)
06/26/07		4,370,000.00	($134,799,054.00)	5.2600%	($19,695.64)
06/27/07		3,182,000.00	($131,617,054.00)	5.2600%	($19,230.71)
06/28/07	9,235,000.00		($140,852,054.00)	5.2600%	($20,580.05)
06/29/07		543,000.00	($140,309,054.00)	5.2600%	($20,500.71)
06/30/07			($140,309,054.00)	5.2600%	($20,500.71)
	121,692,000.00	**108,430,000.00**		**5.2600%**	**(555,664.76)**

Money Pool Statements - July 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($140,309,054.00)		
07/01/07			($140,309,054.00)	5.2800%	($20,578.66)
07/02/07		2,500,000.00	($137,809,054.00)	5.2800%	($20,211.99)
07/03/07		4,950,000.00	($132,859,054.00)	5.2800%	($19,485.99)
07/04/07			($132,859,054.00)	5.2800%	($19,485.99)
07/05/07		4,710,000.00	($128,149,054.00)	5.2800%	($18,795.19)
07/06/07		6,700,000.00	($121,449,054.00)	5.2800%	($17,812.53)
07/07/07			($121,449,054.00)	5.2800%	($17,812.53)
07/08/07			($121,449,054.00)	5.2800%	($17,812.53)
07/09/07		3,518,000.00	($117,931,054.00)	5.2800%	($17,296.55)
07/10/07		3,255,000.00	($114,676,054.00)	5.2800%	($16,819.15)
07/11/07		5,320,000.00	($109,356,054.00)	5.2800%	($16,038.89)
07/12/07	8,035,000.00		($117,391,054.00)	5.2800%	($17,217.35)
07/13/07		510,000.00	($116,881,054.00)	5.2800%	($17,142.55)
07/14/07			($116,881,054.00)	5.2800%	($17,142.55)
07/15/07			($116,881,054.00)	5.2800%	($17,142.55)
07/16/07		640,000.00	($116,241,054.00)	5.2800%	($17,048.69)
07/17/07		7,440,000.00	($108,801,054.00)	5.2800%	($15,957.49)
07/18/07	8,735,000.00		($117,536,054.00)	5.2800%	($17,238.62)
07/19/07	59,235,000.00		($176,771,054.00)	5.2800%	($25,926.42)
07/20/07		1,579,000.00	($175,192,054.00)	5.2800%	($25,694.83)
07/21/07			($175,192,054.00)	5.2800%	($25,694.83)
07/22/07			($175,192,054.00)	5.2800%	($25,694.83)
07/23/07		1,530,000.00	($173,662,054.00)	5.2800%	($25,470.43)
07/24/07	11,670,000.00		($185,332,054.00)	5.2800%	($27,182.03)
07/25/07	18,330,000.00		($203,662,054.00)	5.2800%	($29,870.43)
07/26/07		3,360,000.00	($200,302,054.00)	5.2800%	($29,377.63)
07/27/07		1,587,000.00	($198,715,054.00)	5.2800%	($29,144.87)
07/28/07			($198,715,054.00)	5.2800%	($29,144.87)
07/29/07			($198,715,054.00)	5.2800%	($29,144.87)
07/30/07		3,550,000.00	($195,165,054.00)	5.2800%	($28,624.21)
07/31/07		3,805,000.00	($191,360,054.00)	5.2800%	($28,066.14)
	106,005,000.00	**54,954,000.00**		**5.2800%**	**(680,076.19)**

Money Pool Statements - August 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($191,360,054.00)		
08/01/07	1,300,000.00		($192,660,054.00)	5.2400%	($28,042.74)
08/02/07	9,800,000.00		($202,460,054.00)	5.2400%	($29,469.19)
08/03/07		11,575,000.00	($190,885,054.00)	5.2400%	($27,784.38)
08/04/07			($190,885,054.00)	5.2400%	($27,784.38)
08/05/07			($190,885,054.00)	5.2400%	($27,784.38)
08/06/07		7,700,000.00	($183,185,054.00)	5.2400%	($26,663.60)
08/07/07		3,840,000.00	($179,345,054.00)	5.2400%	($26,104.67)
08/08/07		6,145,000.00	($173,200,054.00)	5.2400%	($25,210.23)
08/09/07		2,735,000.00	($170,465,054.00)	5.2400%	($24,812.14)
08/10/07		1,345,000.00	($169,120,054.00)	5.2400%	($24,616.36)
08/11/07			($169,120,054.00)	5.2400%	($24,616.36)
08/12/07			($169,120,054.00)	5.2400%	($24,616.36)
08/13/07		3,000,000.00	($166,120,054.00)	5.2400%	($24,179.70)
08/14/07		3,642,000.00	($162,478,054.00)	5.2400%	($23,649.58)
08/15/07	11,420,000.00		($173,898,054.00)	5.2400%	($25,311.83)
08/16/07	13,425,000.00		($187,323,054.00)	5.2400%	($27,265.91)
08/17/07	5,520,000.00		($192,843,054.00)	5.2400%	($28,069.38)
08/18/07			($192,843,054.00)	5.2400%	($28,069.38)
08/19/07			($192,843,054.00)	5.2400%	($28,069.38)
08/20/07		4,652,000.00	($188,191,054.00)	5.2400%	($27,392.25)
08/21/07		3,455,000.00	($184,736,054.00)	5.2400%	($26,889.36)
08/22/07		2,845,000.00	($181,891,054.00)	5.2400%	($26,475.25)
08/23/07		3,143,000.00	($178,748,054.00)	5.2400%	($26,017.77)
08/24/07	3,390,000.00		($182,138,054.00)	5.2400%	($26,511.21)
08/25/07			($182,138,054.00)	5.2400%	($26,511.21)
08/26/07			($182,138,054.00)	5.2400%	($26,511.21)
08/27/07	71,903,000.00		($254,041,054.00)	5.2400%	($36,977.09)
08/28/07		2,047,000.00	($251,994,054.00)	5.2400%	($36,679.13)
08/29/07	11,710,000.00		($263,704,054.00)	5.2400%	($38,383.59)
08/30/07		3,805,000.00	($259,899,054.00)	5.2400%	($37,829.75)
08/31/07		3,855,000.00	($256,044,054.00)	5.2400%	($37,268.63)
	128,468,000.00	**63,784,000.00**		**5.2400%**	**(875,566.40)**

Money Pool Statements - September 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($256,044,054.00)		
09/01/07			($256,044,054.00)	5.6200%	($39,971.32)
09/02/07			($256,044,054.00)	5.6200%	($39,971.32)
09/03/07			($256,044,054.00)	5.6200%	($39,971.32)
09/04/07		2,500,000.00	($253,544,054.00)	5.6200%	($39,581.04)
09/05/07		3,582,000.00	($249,962,054.00)	5.6200%	($39,021.85)
09/06/07		3,120,000.00	($246,842,054.00)	5.6200%	($38,534.79)
09/07/07		4,050,000.00	($242,792,054.00)	5.6200%	($37,902.54)
09/08/07			($242,792,054.00)	5.6200%	($37,902.54)
09/09/07			($242,792,054.00)	5.6200%	($37,902.54)
09/10/07		4,790,000.00	($238,002,054.00)	5.6200%	($37,154.77)
09/11/07		5,745,000.00	($232,257,054.00)	5.6200%	($36,257.91)
09/12/07		6,200,000.00	($226,057,054.00)	5.6200%	($35,290.02)
09/13/07		7,305,000.00	($218,752,054.00)	5.6200%	($34,149.63)
09/14/07		105,230,000.00	($113,522,054.00)	5.6200%	($17,722.05)
09/15/07			($113,522,054.00)	5.6200%	($17,722.05)
09/16/07			($113,522,054.00)	5.6200%	($17,722.05)
09/17/07	11,527,000.00		($125,049,054.00)	5.6200%	($19,521.55)
09/18/07		6,275,000.00	($118,774,054.00)	5.6200%	($18,541.95)
09/19/07		5,568,000.00	($113,206,054.00)	5.6200%	($17,672.72)
09/20/07		14,590,000.00	($98,616,054.00)	5.6200%	($15,395.06)
09/21/07	11,866,000.00		($110,482,054.00)	5.6200%	($17,247.48)
09/22/07			($110,482,054.00)	5.6200%	($17,247.48)
09/23/07			($110,482,054.00)	5.6200%	($17,247.48)
09/24/07		640,000.00	($109,842,054.00)	5.6200%	($17,147.57)
09/25/07		49,605,000.00	($60,237,054.00)	5.6200%	($9,403.67)
09/26/07	54,435,000.00		($114,672,054.00)	5.6200%	($17,901.58)
09/27/07		4,497,000.00	($110,175,054.00)	5.6200%	($17,199.55)
09/28/07		4,872,000.00	($105,303,054.00)	5.6200%	($16,438.98)
09/29/07			($105,303,054.00)	5.6200%	($16,438.98)
09/30/07			($105,303,054.00)	5.6200%	($16,438.98)
	77,828,000.00	**228,569,000.00**		**5.6200%**	**(780,620.77)**

Money Pool Statements - October 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($105,303,054.00)		
10/01/07		1,430,000.00	($103,873,054.00)	5.0500%	($14,571.08)
10/02/07		5,970,000.00	($97,903,054.00)	5.0500%	($13,733.62)
10/03/07	5,260,000.00		($103,163,054.00)	5.0500%	($14,471.48)
10/04/07		3,984,000.00	($99,179,054.00)	5.0500%	($13,912.62)
10/05/07		1,550,000.00	($97,629,054.00)	5.0500%	($13,695.19)
10/06/07			($97,629,054.00)	5.0500%	($13,695.19)
10/07/07			($97,629,054.00)	5.0500%	($13,695.19)
10/08/07			($97,629,054.00)	5.0500%	($13,695.19)
10/09/07		4,508,000.00	($93,121,054.00)	5.0500%	($13,062.81)
10/10/07		8,790,000.00	($84,331,054.00)	5.0500%	($11,829.77)
10/11/07		11,203,000.00	($73,128,054.00)	5.0500%	($10,258.24)
10/12/07		2,948,000.00	($70,180,054.00)	5.0500%	($9,844.70)
10/13/07			($70,180,054.00)	5.0500%	($9,844.70)
10/14/07			($70,180,054.00)	5.0500%	($9,844.70)
10/15/07	10,612,000.00		($80,792,054.00)	5.0500%	($11,333.33)
10/16/07		4,220,000.00	($76,572,054.00)	5.0500%	($10,741.36)
10/17/07		5,028,000.00	($71,544,054.00)	5.0500%	($10,036.04)
10/18/07	18,265,000.00		($89,809,054.00)	5.0500%	($12,598.21)
10/19/07	20,529,000.00		($110,338,054.00)	5.0500%	($15,477.98)
10/20/07			($110,338,054.00)	5.0500%	($15,477.98)
10/21/07			($110,338,054.00)	5.0500%	($15,477.98)
10/22/07		3,240,000.00	($107,098,054.00)	5.0500%	($15,023.48)
10/23/07		11,658,000.00	($95,440,054.00)	5.0500%	($13,388.12)
10/24/07		1,005,000.00	($94,435,054.00)	5.0500%	($13,247.14)
10/25/07		55,610,000.00	($38,825,054.00)	5.0500%	($5,446.29)
10/26/07	41,740,000.00		($80,565,054.00)	5.0500%	($11,301.49)
10/27/07			($80,565,054.00)	5.0500%	($11,301.49)
10/28/07			($80,565,054.00)	5.0500%	($11,301.49)
10/29/07		25,100,000.00	($55,465,054.00)	5.0500%	($7,780.51)
10/30/07		948,000.00	($54,517,054.00)	5.0500%	($7,647.53)
10/31/07		3,172,000.00	($51,345,054.00)	5.0500%	($7,202.57)
	96,406,000.00	**150,364,000.00**		**5.0500%**	**(370,937.47)**

Money Pool Statements - November 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($51,345,054.00)		
11/01/07		3,120,000.00	($48,225,054.00)	4.7200%	($6,322.84)
11/02/07		1,600,000.00	($46,625,054.00)	4.7200%	($6,113.06)
11/03/07			($46,625,054.00)	4.7200%	($6,113.06)
11/04/07			($46,625,054.00)	4.7200%	($6,113.06)
11/05/07		3,635,000.00	($42,990,054.00)	4.7200%	($5,636.47)
11/06/07	9,375,000.00		($52,365,054.00)	4.7200%	($6,865.64)
11/07/07		3,435,000.00	($48,930,054.00)	4.7200%	($6,415.27)
11/08/07		7,304,000.00	($41,626,054.00)	4.7200%	($5,457.64)
11/09/07		2,870,000.00	($38,756,054.00)	4.7200%	($5,081.35)
11/10/07			($38,756,054.00)	4.7200%	($5,081.35)
11/11/07			($38,756,054.00)	4.7200%	($5,081.35)
11/12/07			($38,756,054.00)	4.7200%	($5,081.35)
11/13/07		1,289,000.00	($37,467,054.00)	4.7200%	($4,912.35)
11/14/07		10,936,000.00	($26,531,054.00)	4.7200%	($3,478.52)
11/15/07	11,025,000.00		($37,556,054.00)	4.7200%	($4,924.02)
11/16/07	11,947,000.00		($49,503,054.00)	4.7200%	($6,490.40)
11/17/07			($49,503,054.00)	4.7200%	($6,490.40)
11/18/07			($49,503,054.00)	4.7200%	($6,490.40)
11/19/07		2,280,000.00	($47,223,054.00)	4.7200%	($6,191.47)
11/20/07		5,957,000.00	($41,266,054.00)	4.7200%	($5,410.44)
11/21/07	7,100,000.00		($48,366,054.00)	4.7200%	($6,341.33)
11/22/07			($48,366,054.00)	4.7200%	($6,341.33)
11/23/07			($48,366,054.00)	4.7200%	($6,341.33)
11/24/07			($48,366,054.00)	4.7200%	($6,341.33)
11/25/07			($48,366,054.00)	4.7200%	($6,341.33)
11/26/07	81,180,000.00		($129,546,054.00)	4.7200%	($16,984.93)
11/27/07		3,034,000.00	($126,512,054.00)	4.7200%	($16,587.14)
11/28/07		2,870,000.00	($123,642,054.00)	4.7200%	($16,210.85)
11/29/07		7,745,000.00	($115,897,054.00)	4.7200%	($15,195.39)
11/30/07	795,000.00		($116,692,054.00)	4.7200%	($15,299.62)
	121,422,000.00	**56,075,000.00**	**65,347,000.00**	**4.7200%**	**(225,735.02)**

Money Pool Statements - December 2007
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($116,692,054.00)		
12/01/07			($116,692,054.00)	4.7500%	($15,396.87)
12/02/07			($116,692,054.00)	4.7500%	($15,396.87)
12/03/07		585,000.00	($116,107,054.00)	4.7500%	($15,319.68)
12/04/07		3,695,000.00	($112,412,054.00)	4.7500%	($14,832.15)
12/05/07		5,510,000.00	($106,902,054.00)	4.7500%	($14,105.13)
12/06/07	9,750,000.00		($116,652,054.00)	4.7500%	($15,391.59)
12/07/07		3,340,000.00	($113,312,054.00)	4.7500%	($14,950.90)
12/08/07			($113,312,054.00)	4.7500%	($14,950.90)
12/09/07			($113,312,054.00)	4.7500%	($14,950.90)
12/10/07		3,870,000.00	($109,442,054.00)	4.7500%	($14,440.27)
12/11/07		5,580,000.00	($103,862,054.00)	4.7500%	($13,704.02)
12/12/07		3,865,000.00	($99,997,054.00)	4.7500%	($13,194.06)
12/13/07		5,057,000.00	($94,940,054.00)	4.7500%	($12,526.81)
12/14/07		1,470,000.00	($93,470,054.00)	4.7500%	($12,332.85)
12/15/07			($93,470,054.00)	4.7500%	($12,332.85)
12/16/07			($93,470,054.00)	4.7500%	($12,332.85)
12/17/07	10,600,000.00		($104,070,054.00)	4.7500%	($13,731.47)
12/18/07		4,888,600.00	($99,181,454.00)	4.7500%	($13,086.44)
12/19/07		5,640,000.00	($93,541,454.00)	4.7500%	($12,342.28)
12/20/07		89,550,000.00	($3,991,454.00)	4.7500%	($526.65)
12/21/07	4,300,000.00		($8,291,454.00)	4.7500%	($1,094.01)
12/22/07			($8,291,454.00)	4.7500%	($1,094.01)
12/23/07			($8,291,454.00)	4.7500%	($1,094.01)
12/24/07			($8,291,454.00)	4.7500%	($1,094.01)
12/25/07			($8,291,454.00)	4.7500%	($1,094.01)
12/26/07	27,253,000.00		($35,544,454.00)	4.7500%	($4,689.89)
12/27/07		3,850,000.00	($31,694,454.00)	4.7500%	($4,181.91)
12/28/07		2,400,000.00	($29,294,454.00)	4.7500%	($3,865.24)
12/29/07			($29,294,454.00)	4.7500%	($3,865.24)
12/30/07			($29,294,454.00)	4.7500%	($3,865.24)
12/31/07		6,075,000.00	($23,219,454.00)	4.7500%	($3,063.68)
	51,903,000.00	**145,375,600.00**		**4.7500%**	**(294,846.79)**

Money Pool Statements - January 2008
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($23,219,454.00)		
01/01/08			($23,219,454.00)	4.9800%	($3,212.02)
01/02/08		1,100,000.00	($22,119,454.00)	4.9800%	($3,059.86)
01/03/08		2,875,000.00	($19,244,454.00)	4.9800%	($2,662.15)
01/04/08		2,530,000.00	($16,714,454.00)	4.9800%	($2,312.17)
01/05/08			($16,714,454.00)	4.9800%	($2,312.17)
01/06/08			($16,714,454.00)	4.9800%	($2,312.17)
01/07/08	1,225,000.00		($17,939,454.00)	4.9800%	($2,481.62)
01/08/08		18,000.00	($17,921,454.00)	4.9800%	($2,479.13)
01/09/08		4,050,000.00	($13,871,454.00)	4.9800%	($1,918.88)
01/10/08		5,580,000.00	($8,291,454.00)	4.9800%	($1,146.98)
01/11/08		255,000.00	($8,036,454.00)	4.9800%	($1,111.71)
01/12/08			($8,036,454.00)	4.9800%	($1,111.71)
01/13/08			($8,036,454.00)	4.9800%	($1,111.71)
01/14/08		2,235,000.00	($5,801,454.00)	4.9800%	($802.53)
01/15/08	13,240,000.00		($19,041,454.00)	4.9800%	($2,634.07)
01/16/08		7,745,000.00	($11,296,454.00)	4.9800%	($1,562.68)
01/17/08		5,765,000.00	($5,531,454.00)	4.9800%	($765.18)
01/18/08	33,985,000.00		($39,516,454.00)	4.9800%	($5,466.44)
01/19/08			($39,516,454.00)	4.9800%	($5,466.44)
01/20/08			($39,516,454.00)	4.9800%	($5,466.44)
01/21/08			($39,516,454.00)	4.9800%	($5,466.44)
01/22/08		19,805,000.00	($19,711,454.00)	4.9800%	($2,726.75)
01/23/08		8,407,000.00	($11,304,454.00)	4.9800%	($1,563.78)
01/24/08	520,000.00		($11,824,454.00)	4.9800%	($1,635.72)
01/25/08	24,431,000.00		($36,255,454.00)	4.9800%	($5,015.34)
01/26/08			($36,255,454.00)	4.9800%	($5,015.34)
01/27/08			($36,255,454.00)	4.9800%	($5,015.34)
01/28/08	41,995,000.00		($78,250,454.00)	4.9800%	($10,824.65)
01/29/08		4,583,000.00	($73,667,454.00)	4.9800%	($10,190.66)
01/30/08		8,646,000.00	($65,021,454.00)	4.9800%	($8,994.63)
01/31/08		5,985,000.00	($59,036,454.00)	4.9800%	($8,166.71)
	115,396,000.00	**79,579,000.00**	**35,817,000.00**	**4.9800%**	**(114,011.42)**

Money Pool Statements - February 2008
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($59,036,454.00)		
02/01/08		4,280,000.00	($54,756,454.00)	3.0800%	($4,684.72)
02/02/08			($54,756,454.00)	3.0800%	($4,684.72)
02/03/08			($54,756,454.00)	3.0800%	($4,684.72)
02/04/08		3,740,000.00	($51,016,454.00)	3.0800%	$0.00
02/04/08		750,000.00	($50,266,454.00)	3.0800%	($4,300.57)
02/05/08		4,475,000.00	($45,791,454.00)	3.0800%	($3,917.71)
02/06/08		7,990,000.00	($37,801,454.00)	3.0800%	($3,234.12)
02/07/08		3,065,000.00	($34,736,454.00)	3.0800%	($2,971.90)
02/08/08		2,112,000.00	($32,624,454.00)	3.0800%	($2,791.20)
02/09/08			($32,624,454.00)	3.0800%	($2,791.20)
02/10/08			($32,624,454.00)	3.0800%	($2,791.20)
02/11/08	7,200,000.00		($39,824,454.00)	3.0800%	($3,407.20)
02/12/08			($39,824,454.00)	3.0800%	($3,407.20)
02/13/08		15,725,000.00	($24,099,454.00)	3.0800%	($2,061.84)
02/14/08		6,675,000.00	($17,424,454.00)	3.0800%	($1,490.76)
02/15/08	13,745,000.00		($31,169,454.00)	3.0800%	($2,666.72)
02/16/08			($31,169,454.00)	3.0800%	($2,666.72)
02/17/08			($31,169,454.00)	3.0800%	($2,666.72)
02/18/08			($31,169,454.00)	3.0800%	($2,666.72)
02/19/08		11,320,000.00	($19,849,454.00)	3.0800%	($1,698.23)
02/20/08		11,665,000.00	($8,184,454.00)	3.0800%	($700.23)
02/21/08		1,160,000.00	($7,024,454.00)	3.0800%	($600.98)
02/22/08		2,430,000.00	($4,594,454.00)	3.0800%	($393.08)
02/23/08			($4,594,454.00)	3.0800%	($393.08)
02/24/08			($4,594,454.00)	3.0800%	($393.08)
02/25/08	26,745,000.00		($31,339,454.00)	3.0800%	($2,681.26)
02/26/08	30,922,000.00		($62,261,454.00)	3.0800%	($5,326.81)
02/27/08		6,480,000.00	($55,781,454.00)	3.0800%	($4,772.41)
02/28/08		4,011,000.00	($51,770,454.00)	3.0800%	($4,429.25)
02/29/08		3,770,000.00	($48,000,454.00)	3.0800%	($4,106.71)
	78,612,000.00	**89,648,000.00**	**(11,036,000.00)**	**3.0800%**	**(83,381.06)**

Money Pool Statements - March 2008
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($48,000,454.00)		
03/01/08			($48,000,454.00)	3.0800%	($4,106.71)
03/02/08			($48,000,454.00)	3.0800%	($4,106.71)
03/03/08		2,775,000.00	($45,225,454.00)	3.0800%	($3,869.29)
03/04/08		1,951,000.00	($43,274,454.00)	3.0800%	($3,702.37)
03/05/08		4,990,000.00	($38,284,454.00)	3.0800%	($3,275.45)
03/06/08		5,896,000.00	($32,388,454.00)	3.0800%	($2,771.01)
03/07/08	6,092,000.00		($38,480,454.00)	3.0800%	($3,292.22)
03/08/08			($38,480,454.00)	3.0800%	($3,292.22)
03/09/08			($38,480,454.00)	3.0800%	($3,292.22)
03/10/08		6,810,000.00	($31,670,454.00)	3.0800%	($2,709.58)
03/11/08		60,000.00	($31,610,454.00)	3.0800%	($2,704.45)
03/12/08		3,785,000.00	($27,825,454.00)	3.0800%	($2,380.62)
03/13/08		3,775,000.00	($24,050,454.00)	3.0800%	($2,057.65)
03/14/08		2,815,000.00	($21,235,454.00)	3.0800%	($1,816.81)
03/15/08			($21,235,454.00)	3.0800%	($1,816.81)
03/16/08			($21,235,454.00)	3.0800%	($1,816.81)
03/17/08	9,945,000.00		($31,180,454.00)	3.0800%	($2,667.66)
03/18/08		4,650,000.00	($26,530,454.00)	3.0800%	($2,269.83)
03/19/08		10,666,000.00	($15,864,454.00)	3.0800%	($1,357.29)
03/20/08	41,000,000.00		($56,864,454.00)	3.0800%	($4,865.07)
03/21/08			($56,864,454.00)	3.0800%	($4,865.07)
03/22/08			($56,864,454.00)	3.0800%	($4,865.07)
03/23/08			($56,864,454.00)	3.0800%	($4,865.07)
03/24/08		6,550,000.00	($50,314,454.00)	3.0800%	($4,304.68)
03/25/08	22,100,000.00		($72,414,454.00)	3.0800%	($6,195.46)
03/26/08	18,064,000.00		($90,478,454.00)	3.0800%	($7,740.93)
03/27/08		11,590,000.00	($78,888,454.00)	3.0800%	($6,749.35)
03/28/08		28,445,000.00	($50,443,454.00)	3.0800%	($4,315.72)
03/29/08			($50,443,454.00)	3.0800%	($4,315.72)
03/30/08			($50,443,454.00)	3.0800%	($4,315.72)
03/31/08		380,000.00	($50,063,454.00)	3.0800%	($4,283.21)
	97,201,000.00	***95,138,000.00***	***2,063,000.00***	***3.0800%***	***(114,986.78)***

Money Pool Statements - April 2008
POOL - KU

Date	Debit	Credit	Balance	AVG Debt Rate	Interest
Beginning Balance			($50,063,454.00)		
04/01/08		2,400,000.00	($47,663,454.00)	2.6300%	($3,482.08)
04/02/08		5,830,000.00	($41,833,454.00)	2.6300%	($3,056.17)
04/03/08		4,090,000.00	($37,743,454.00)	2.6300%	($2,757.37)
04/04/08	6,385,000.00		($44,128,454.00)	2.6300%	($3,223.83)
04/05/08			($44,128,454.00)	2.6300%	($3,223.83)
04/06/08			($44,128,454.00)	2.6300%	($3,223.83)
04/07/08		3,030,000.00	($41,098,454.00)	2.6300%	($3,002.47)
04/08/08		2,500,000.00	($38,598,454.00)	2.6300%	($2,819.83)
04/09/08		7,618,000.00	($30,980,454.00)	2.6300%	($2,263.29)
04/10/08		6,290,000.00	($24,690,454.00)	2.6300%	($1,803.77)
04/11/08		3,627,000.00	($21,063,454.00)	2.6300%	($1,538.80)
04/12/08			($21,063,454.00)	2.6300%	($1,538.80)
04/13/08			($21,063,454.00)	2.6300%	($1,538.80)
04/14/08		3,838,000.00	($17,225,454.00)	2.6300%	($1,258.42)
04/15/08	23,789,000.00		($41,014,454.00)	2.6300%	($2,996.33)
04/16/08		3,465,000.00	($37,549,454.00)	2.6300%	($2,743.20)
04/17/08	7,578,000.00		($45,127,454.00)	2.6300%	($3,296.81)
04/18/08	13,956,000.00		($59,083,454.00)	2.6300%	($4,316.37)
04/19/08			($59,083,454.00)	2.6300%	($4,316.37)
04/20/08			($59,083,454.00)	2.6300%	($4,316.37)
04/21/08		4,090,000.00	($54,993,454.00)	2.6300%	($4,017.58)
04/22/08		3,526,000.00	($51,467,454.00)	2.6300%	($3,759.98)
04/23/08		9,690,000.00	($41,777,454.00)	2.6300%	($3,052.08)
04/24/08		4,800,000.00	($36,977,454.00)	2.6300%	($2,701.41)
04/25/08	66,020,000.00		($102,997,454.00)	2.6300%	($7,524.54)
04/26/08			($102,997,454.00)	2.6300%	($7,524.54)
04/27/08			($102,997,454.00)	2.6300%	($7,524.54)
04/28/08		2,328,000.00	($100,669,454.00)	2.6300%	($7,354.46)
04/29/08		4,751,000.00	($95,918,454.00)	2.6300%	($7,007.38)
04/30/08		2,616,000.00	($93,302,454.00)	2.6300%	($6,816.26)
	117,728,000.00	**74,489,000.00**	**43,239,000.00**	**2.6300%**	**(113,999.51)**

Kentucky Utilities Company - Test Year

Debt (Long-Term)

Kentucky Utilities Company G/L Acct#			Coupon		5/1/2007	May 2007 - new bonds issued	April 2008 - Reacquired $16.7M CC 2006C bonds	June 2007 - additions	September 2007 - additions	October 2007 - additions	December 2007 - additions	4/30/2008
	Pollution Control Bonds											
221146	May 1, 2023	PCS 11	Variable	4.757%	$ 12,900,000							$ 12,900,000
221284 / 221184	February 1, 2032	PCS 12	Variable		20,930,000							20,930,000
221285 / 221185	February 1, 2032	PCS 13	Variable		2,400,000							2,400,000
221286 / 221186	February 1, 2032	PCS 14	Variable		7,400,000							7,400,000
221287 / 221187	February 1, 2032	PCS 15	Variable		2,400,000							2,400,000
221188	October 1, 2032	PCS 16	Variable		96,000,000							96,000,000
221192	October 1, 2034	PCS 17	Variable		50,000,000							50,000,000
221195	June 1, 2035	PSC 18	Variable		13,266,950							13,266,950
221196	June 1, 2035	PSC 19	Variable		13,266,950							13,266,950
221197	June 1, 2036	PSC 20	Variable		16,693,620							16,693,620
221198	June 1, 2036	PCS 21	Variable		16,693,620		$ (16,693,620)					-
221199	October 1, 2034	PCS 22	Variable		54,000,000							54,000,000
221004	February 1, 2026	CC2007A	Variable		-	$ 17,875,000						17,875,000
221005	March 1, 2037	TC2007A	Variable		-	8,927,000						8,927,000
223002	Notes Payable to Fidelia											
	10 Year, issued 4/30/03		4.550%		100,000,000							100,000,000
	10 Year, issued 8/15/03		5.310%		75,000,000							75,000,000
	10 Year, issued 11/24/03		4.240%		33,000,000							33,000,000
	2 Year, issued 12/18/03		2.290%		75,000,000							75,000,000
	8 Year, issued 1/15/04		4.390%		50,000,000							50,000,000
	10 Year, issued 7/08/05		4.375%		50,000,000							50,000,000
	30 Year, issued 6/23/06		6.330%		50,000,000							50,000,000
	10 Year, issued 10/25/06		5.675%		50,000,000							50,000,000
	15 Year, issued 2/7/2007		5.690%		53,000,000							53,000,000
	30 Year, issued 3/30/2007		5.860%		75,000,000							75,000,000
	10 Year, issued 6/20/2007		5.980%		-			$ 50,000,000				50,000,000
	20 Year, issued 9/14/2007		5.960%		-				$ 100,000,000			100,000,000
	12 Year, issued 10/25/2007		5.710%		-					$ 70,000,000		70,000,000
	7 Year, issued 12/20/2007		5.450%		-						$ 100,000,000	100,000,000
		Total Long-Term Debt			916,951,140	26,802,000	(16,693,620)	50,000,000	100,000,000	70,000,000	100,000,000	1,247,059,520

Bond Borrowings	26,802,000
Reacquired Bonds	(16,693,620)
Notes Payable Borrowings	320,000,000

Repurchased Bonds

		Coupon	Amount	Existing Insurer	Bond Conversion Date
Kentucky Utilities Company					
June 1, 2036	PCS 21	Variable	16,693,620	XL	4/16/2008
Total - KU			16,693,620		

Dickson, Gloria

From:	Horne, Elliott
Sent:	Thursday, May 24, 2007 11:40 AM
To:	Rives, Brad; Charnas, Shannon; Kelly, Mimi; Dickson, Gloria
Cc:	Arbough, Dan; Harris, Donald; Lasley, Diane; Strange, Vicki; Neal, Susan; Scott, Valerie; Watson, Sandy
Subject:	New KU Bond Issuances

KU closed on two new bond issuances today (May 24, 2007). The terms of the new bonds are shown below:

Series name	County of Carroll 2007 Series A
Amount	$17,875,000
Interest rate	variable - initially be issued in a 7-day Auction period (subsequent auctions occurring each Wednesday)
Initial interest rate	3 80%
Maturity date	February 1, 2026
Trustee:	Deutsche Bank
CUSIP #:	*14483RAG2*
First Auction:	May 30, 2007
First Interest Payment:	May 31, 2007 (each Thursday thereafter)

Series name	County of Trimble 2007 Series A
Amount	$8,927,000
Interest rate	variable - initially be issued in a 7-day Auction period (subsequent auctions occurring each Wednesday)
Initial interest rate	3.80%
Maturity date	March 1, 2037
Trustee:	Deutsche Bank
CUSIP #:	896221AB4
First Auction:	May 30, 2007
First Interest Payment:	May 31, 2007 (each Thursday thereafter)

The new bonds are insured by Ambac and cannot be put back to KU by the investors. Based on this and consistent with how we show the other auction rate bonds, these bonds should be classified as long-term debt.

Please call me if you have any questions.

Bank 19
Bank of Commerce

CUSTOMER CONNECTION
BANK OF AMERICA N.A.
DALLAS TEXAS 75283-2406

Account Number 3752099120
01 01 149 01 M0000 E# 0
Last Statement 05/31/2007
This Statement 06/29/2007

Customer Service
1-800-325-6999

131092

KENTUCKY UTILITIES COMPANY

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ANALYZED CHECKING

Deposits and Credits

Date Posted	Customer Reference	Amount	Description	Bank Reference
06/18		116,000.00	WIRE TYPE:WIRE IN DATE: 070618 TIME:1231 ET TRN:2007061800184429 SEQ:070618012474/001459 ORIG:KENTUCKY UTILITIES ID:000153910087961 SND BK:U.S. BANK,N.A. ID:123000848 PMT DET:070618012474 I HBCODE KUU KLU	00370184429
06/18		3,050,000.00	WIRE TYPE:WIRE IN DATE: 070618 TIME:1051 ET TRN:2007061800130646 SEQ:0345060169ZO/007365 ORIG:KENTUCKY UTILITIES SND BK:JPMORGAN CHASE BANK , NA ID:021000021 PMT DET:WRE OF 07/06/18 IHBCODE-KUU-KLU	00370130646
06/18		9,710,000.00	WIRE TYPE:BOOK IN DATE:070618 TIME:1106 ET TRN:2007061800135725 SNDR REF:15370031 ORIG:E.ON U S LLC ID:003752102075 PMT DET:IHBCODE-UTP-KUU	00370135725
06/19		4,028.10	Sweep - Trans From Mutual Fund	03915100769
06/19		378,000.00	WIRE TYPE:WIRE IN DATE: 070619 TIME:1050 ET TRN:2007061900112096 SEQ:070619008604/000887 ORIG:KENTUCKY UTILITIES ID:000153910087961 SND BK:U.S. BANK,N.A. ID:123000848 PMT DET:070619008604 I HBCODE KUU KLU	00370112096
06/19		6,570,000.00	WIRE TYPE:WIRE IN DATE: 070619 TIME:1053 ET TRN:2007061900113682 SEQ:0390900178ZO/007055 ORIG:KENTUCKY UTILITIES SND BK:JPMORGAN CHASE BANK , NA ID:021000021 PMT DET:WRE OF 07/06/19 IHBCODE-KUU-KLU	00370113682
06/19		63,130,000.00	WIRE TYPE:BOOK IN DATE:070619 TIME:1125 ET TRN:2007061900118918 SNDR REF:15389350 ORIG:E.ON U S LLC ID:003752102075 PMT DET:IHBCODE-UTP-KLU	00370118918
06/20		319,000.00	WIRE TYPE:WIRE IN DATE: 070620 TIME:1147 ET TRN:2007062000161475 SEQ:070620011384/001060 ORIG:KENTUCKY UTILITIES ID:000153910087961 SND BK:U.S. BANK,N.A. ID:123000848 PMT DET:070620011384 I HBCODE KUU KUU	00370161475
06/20		696,032.13	WIRE TYPE:WIRE IN DATE: 070620 TIME:1436 ET TRN:2007062000218549 SEQ:070620020530/001965 ORIG:ST PAUL MN ID:USBANK SND BK:U.S. BANK,N.A. ID:091000022 PMT DET:070620020530 PROPERTY RELEASE	00370218549
06/20		3,668,000.00	WIRE TYPE:WIRE IN DATE: 070620 TIME:1152 ET TRN:2007062000163294 SEQ:0486700171ZO/002440 ORIG:KENTUCKY UTILITIES AND BK:JPMORGAN CHASE BANK , NA ID:021000021 PMT DET:WRE OF 07/06/20 IHBCODE KUU-KLU	00370163294
06/20		50,000,000.00	WIRE TYPE:WIRE IN DATE: 070620 TIME:1136 ET TRN:2007062000157834 SEQ:070620010715/001066 ORIG:FIDELIA CO 3751 CENTERVIL ID:FIDELIACORPORATI SND BK:U.S. BANK,N.A. ID:091000022 PMT DET:070620010715 KENTUCKY UTILITIES LOAN M20070620UA00466000	00370157834

KENTUCKY UTILITIES CO
ELECTRONIC FUNDS TRANSFER SYSTEM
CASH RECEIPTS LEDGER
REPORT NO. CA2930A

RUN DATE: 9/20/07
RUN TIME: 23.41.49

ACTIVITY DATE: 09/20/07

BANK NUMBER	BANK NAME	ADJ CODE	CODE NAME	ADJUSTMENT DESCRIPTION		AMOUNT
03712						8,196.95
					BANK TOTAL	
03852	BB&T	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		15,482.62
03852						15,482.62
					BANK TOTAL	
04212	CUMBERLAND VALLEY NATIONAL	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		23,172.09
04212						23,172.09
					BANK TOTAL	
04311	FIRST STATE FINANCIAL	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		37,026.59
04311						37,026.59
					BANK TOTAL	
04412	BANK OF HARLAN	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		17,510.66
04412						17,510.66
					BANK TOTAL	
04511	CITIZENS NATIONAL BANK	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		31,526.40
04511						31,526.40
					BANK TOTAL	
07612	FIRST BANK & TRUST	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		19,628.08
07612						19,628.08
					BANK TOTAL	
07731	LEE BANK AND TRUST CO	LO	LOCAL OFFICE RECEIPT	DAILY RECEIPTS		7,312.74
07731						7,312.74
					BANK TOTAL	
						5,866,513.50
					CODE TOTAL	
			Fidelia			
00018	BANK OF AMERICA	OR	OTHER RECEIPTS	110.301.015590.015590.223002.0000.0699.0000DH		99,000,000.00
00018	BANK OF AMERICA	OR	OTHER RECEIPTS	110.301.015590.015590.223002.0000.0699.0000DH		1,000,000.00
00018						100,000,000.00 p.3
					BANK TOTAL	
						100,000,000.00
					CODE TOTAL	
00003	BANK ONE, NA	TI	TRANSFERS IN	CASH CONCENTRATION		359,728.77
00003						359,728.77
					BANK TOTAL	
						359,728.77
					CODE TOTAL	
						107,005,391.82
					COMPANY TOTAL	

5

Dickson, Gloria

From: Wiedmar, John
Sent: Wednesday, September 12, 2007 10:57 AM
To: 'fidelia corp@verizon.net'; 'Morse, Claire'
Cc: 'Lioba.Heintzen@eon.com'; Rives, Brad; Fendig, John; Arbough, Dan; Lasley, Diane; Newton, Gretchen; Dickson, Gloria; Strange, Vicki; Horne, Elliott
Subject: Fidelia Loan to KU

On September 14th, Kentucky Utilities will borrow a $100MM 21-yr intercompany loan from Fidelia. Details of the loan are provided below:

Principal: $100,000,000
Maturity Date: September 14, 2028
Interest Payment Dates: March 14th and September 14th of each year
Interest Rate: Fixed at 5 96% (10 yr treasury rate of 4 38% + spread of 1.58%)
Unsecured Loan

Please let me know if you need additional information

Bank of America
E.ON U.S. LLC
Previous Day All Data Summary and Detail with Text Report

CASH LETTER PRE-ENCODED DEP CR

	895,226.07	0000000000	00722156710	6,680.09	833,723.09	54,822.89
	CUR FR 4426403300					
	692,566.33	0000000000	00722156708	0.00	648,154.57	44,411.76
	CUR FR 4426403300					
	372,037.28	0000000000	00722156706	1,089.50	342,929.39	28,018.39
	CUR FR 4426403300					
	71,882.49	0000000000	00722156707	0.00	67,569.64	4,312.85
	CUR FR 4426403300					
	54,102.82	0000000000	00722156709	0.00	50,729.29	3,373.53
	CUR FR 4426403300					
TOTAL	2,085,814.99	# of Items:	5	7,769.59	1,943,105.98	134,939.42

INCOMING MONEY TRANSFER CREDIT

70,000,000.00	0000000000	00370142075	70,000,000.00	0.00	0.00

WIRE TYPE:WIRE IN DATE: 071025 TIME:1136 ET
TRN:2007102500142075 SEQ:071025012568/001312
ORIG:FIDELIA CO 2751 CENTERVIL ID:FIDELIACORPORATI
SND BK:U.S. BANK N.A. ID:091000022 PMT DET:0710250
12568 KENTUCKY UTILITIES CO W20071025UA00062100000

Henley, Deena

From: Schmidt, Sandy
Sent: Friday, October 26, 2007 11:40 AM
To: Henley, Deena
Subject: RE: Emailing: BofaDirect.TreasuryDirect.pdf

wire pymt

YOU ARE THE WINNER!!!!!!! THE GRAND PRIZE IS..........

YOU GET TO COME BACK ON MONDAY :)

From: Henley, Deena
Sent: Friday, October 26, 2007 11:29 AM
To: Schmidt, Sandy
Subject: Emailing: BofaDirect.TreasuryDirect.pdf

<< File: BofaDirect.TreasuryDirect.pdf >> There is a 70m Fidelia Page 2
0110.301.015590.015590.223002.0000.0699.0000 Correct?

OR

#18

OCT 26 2007

Bank of America
E.ON U.S. LLC
Previous Day Summary and Detail with Text Report

	1,330.51	0000000000	53004063234	1,330.51	0.00	0.00

DJJ RMR DES:PAYMENTS ID:103787
INDN:KENTUCKY UTILITI CO ID:2611329924 CTX
ADDITIONAL INFORMATION IS AVAILABLE FOR THIS PMT
CONTACT A TREASURY SALES OFFICER FOR ASSISTANCE.

TOTAL	69,358.21	# of Items:	2	69,358.21		

PREAUTHORIZED ACH CREDIT

	8,000,770.96	0000000000	53003497571	8,000,770.96	0.00	0.00

LOUISVILLE GAS A DES CORP PMT ID:707870585
INDN:KENTUCKY UTILITIES CO CO ID:1610264150 CCD

	39,102.29	0000000000	53004267268	39,102.29	0.00	0.00

AMAZON.COM INC. DES:Misc. Paym ID:10520294D
INDN:KENTUCKY UTILITIES CO CO ID:9710938319 CCD
PMT INFO:Amazon.com Expense Payments ID#2072364

	32,707.91	0000000000	53003079502	32,707.91	0.00	0.00

METAVANTE CORP DES:SUMMARY METAVANTE CORP
ID:3752099120 CO ID:M391165550 CIE

TOTAL	8,072,581.16	# of Items:	3	8,072,581.16		

ACH SETTLEMENT CREDIT

	224.23	0000000000	54005128763	224.23	0.00	0.00

KENTUCKY UTILIT/ DES:CCD FL# 20073530582
INDN:SETT-KEUTILIT4 CO ID:1610247570 CCD

TOTAL	224.23	# of Items:	1	224.23		

CASH LETTER PRE-ENCODED DEP CR

	1,296,832.30	0000000000	00722160128	515.65	756,865.45	539,451.20
	CUR FR 4426403300					
	433,524.75	0000000000	00722160126	461.23	31,553.03	401,510.49
	CUR FR 4426403300					
	387,050.80	0000000000	00722160125	6.36	344,475.43	42,569.01
	CUR FR 4426403300					
	126,226.52	0000000000	00722160127	0.00	118,057.69	8,168.83
	CUR FR 4426403300					
	13,330.06	0000000000	00722160129	0.00	9,076.82	4,253.24
	CUR FR 4426403300					
TOTAL	2,256,964.43	# of Items:	5	983.24	1,260,028.42	995,952.77

INCOMING MONEY TRANSFER CREDIT

	100,000,000.00	0000000000	00370121474	100,000,000.00	0.00	0.00

WIRE TYPE:WIRE IN DATE: 071220 TIME:0936 ET
TRN:2007122000121474 SEQ:071220005528/000400
ORIG:FIDELIA CORPORATION ID:NA SND BK:U S BANK N.
A ID:091000022 PMT DET:071220005528 KENTUCKY UTIL
ITIES CO W20071220UA0004710000001

No
Fidelia

Schmidt, Sandy

From: Dickson, Gloria
Sent: Tuesday, December 18, 2007 10:24 AM
To: Schmidt, Sandy
Subject: FW: $100 million KU Intercompany Loan from Fidelia

Sandy

I talked to Karen Callahan and she asked that it be booked on day zero or day one.

Gloria

From: Wiedmar, John
Sent: Tuesday, December 18, 2007 9:58 AM
To: 'Morse, Claire'; 'Fidelia Corp'
Cc: 'Lioba.Heintzen@eon.com'; Rives, Brad; Fendig, John; Arbough, Dan; Lasley, Diane; Watson, Sandy; Newton, Gretchen; Dickson, Gloria; Garrett, Chris; Petre, Alex; Horne, Elliott
Subject: $100 million KU Intercompany Loan from Fidelia

On December 20th, KU will borrow $100 million from Fidelia on a 7 year intercompany loan. Details of the loan are provided below:

Principal: $100,000,000
Maturity Date: December 19, 2014
Interest Payment Dates: June 20th and December 20th of each year, commencing June 20, 2008.
Interest Rate: Fixed at 5.45% (7 year treasury rate of 3.84% + spread of 1.61%)
Unsecured Loan

Please let me know if you need additional information.

CR 0110. 301. 015590. 015590. 223002. 0000. 0699. 0000 No
DR 0110. 703. 015590. 015590. 131092. 0000. 0699. 0000 No

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 95

Responding Witness: S. Bradford Rives

Q-95. With reference to pages 21-27 and Exhibit 2, please provide the quarterly capitalization amounts and ratios, including and excluding short-term debt, for the past three years for KU. Please provide the data in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-95. See attached. The requested information is also provided on CD.

Kentucky Utilities Company
Case No. 2008-00251

Attorney General Question No. 95

Responding Witness: S. Bradford Rives

"000 Omitted"

Line No.	Type of Capital	September 30, 2005 Amount	Ratio	December 31, 2005 Amount	Ratio	March 31, 2006 Amount	Ratio	June 30, 2006 Amount	Ratio	September 30, 2006 Amount	Ratio	December 31, 2006 Amount	Ratio
1	Long-Term Debt	$ 733,979	41.16%	$ 746,604	40.19%	$ 710,048	38.38%	$ 759,328	40.10%	$ 775,906	39.47%	$ 842,385	39.50%
2	Short-Term Debt	31,785	1.78%	69,665	3.75%	82,678	4.47%	52,131	2.75%	58,962	3.00%	97,043	4.55%
3	Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
4	Common Equity	1,017,346	57.06%	1,041,377	56.06%	1,057,461	57.15%	1,082,196	57.15%	1,131,097	57.53%	1,193,198	55.95%
5	Total Capitalization	$ 1,783,110	100.00%	$ 1,857,646	100.00%	$ 1,850,186	100.00%	$ 1,893,655	100.00%	$ 1,965,965	100.00%	$ 2,132,626	100.00%

Line No.	Type of Capital	March 31, 2007 Amount	Ratio	June 30, 2007 Amount	Ratio	September 30, 2007 Amount	Ratio	December 31, 2007 Amount	Ratio	March 31, 2008 Amount	Ratio	June 30, 2008 Amount	Ratio
1	Long-Term Debt	$ 916,951	41.92%	$ 993,753	41.27%	$ 1,093,753	42.44%	$ 1,263,753	46.42%	$ 1,263,753	44.81%	$ 1,303,160	43.98%
2	Short-Term Debt	32,043	1.46%	140,309	5.83%	105,303	4.09%	23,219	0.85%	50,063	1.78%	75,443	2.55%
3	Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
4	Common Equity	1,238,564	56.62%	1,273,745	52.90%	1,378,207	53.47%	1,435,516	52.73%	1,506,440	53.41%	1,584,444	53.47%
5	Total Capitalization	$ 2,187,558	100.00%	$ 2,407,807	100.00%	$ 2,577,263	100.00%	$ 2,722,488	100.00%	$ 2,820,257	100.00%	$ 2,963,047	100.00%

Note 1: Total long-term debt includes the short-term portion of long-term debt.
Note 2: The above amounts do not include imputed debt from the purchased power agreements.

Kentucky Utilities Company
Case No. 2008-00251

Attorney General Question No. 95

Responding Witness: S. Bradford Rives

"000 Omitted"

		September 30, 2005		December 31, 2005		March 31, 2006		June 30, 2006		September 30, 2006		December 31, 2006	
Line No.	Type of Capital	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1	Long-Term Debt	$ 733,979	41.91%	$ 746,604	41.76%	$ 710,048	40.17%	$ 759,328	41.23%	$ 775,906	40.69%	$ 842,385	41.38%
2	Short-Term Debt	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
3	Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
4	Common Equity	1,017,346	58.09%	1,041,377	58.24%	1,057,461	59.83%	1,082,196	58.77%	1,131,097	59.31%	1,193,198	58.62%
5	Total Capitalization	$ 1,751,325	100.00%	$ 1,787,981	100.00%	$ 1,767,508	100.00%	$ 1,841,524	100.00%	$ 1,907,002	100.00%	$ 2,035,583	100.00%

		March 31, 2007		June 30, 2007		September 30, 2007		December 31, 2007		March 31, 2008		June 30, 2008	
Line No.	Type of Capital	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1	Long-Term Debt	$ 916,951	42.54%	$ 993,753	43.83%	$ 1,093,753	44.25%	$ 1,263,753	46.82%	$ 1,263,753	45.62%	$ 1,303,160	45.13%
2	Short-Term Debt	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
3	Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
4	Common Equity	1,238,564	57.46%	1,273,745	56.17%	1,378,207	55.75%	1,435,516	53.18%	1,506,440	54.38%	1,584,444	54.87%
5	Total Capitalization	$ 2,155,515	100.00%	$ 2,267,498	100.00%	$ 2,471,960	100.00%	$ 2,699,269	100.00%	$ 2,770,194	100.00%	$ 2,887,604	100.00%

Note 1: Total long-term debt includes the short-term portion of long-term debt.
Note 2: The above amounts do not include imputed debt from the purchased power agreements.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 96

Responding Witness: S. Bradford Rives

Q-96. With reference to pages 21-27 and Exhibit 2, please provide (1) all data, work papers, source documents, and calculations used in computing the short-term and long-term cost rates; (2) all details (issue date, debt amounts, underwriter, underwriting spread, SEC filings, etc.) associated with all actual and pro forma financings used in determining the Company's short-term and long-term debt cost rates; and (3) the methodology, computations, and associated work papers used to compute the debt cost rates for pro forma long-term financings, intercompany loans, and for short-term debt. Please provide the data in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-96. (1) See attachment to response to Question No. 94(1).

(2) See attached. The requested information is also provided on CD.

(3) There are no pro forma financings.

Kentucky Utilities Company

Long Term Debt

Pollution Control Bonds	Issue Date	Debt Amount	Underwriter	Underwriting Spread	SEC Filings
Series 11 - Series A	5/19/2000	$ 12.900.000 00	Morgan Stanley	0 59%	N/A
Series 12	5/23/2002	20.930.000 00	JP Morgan	0 35%	N/A
Series 13	5/23/2002	2,400.000 00	JP Morgan	0 20%	N/A
Series 14	5/23/2002	7.400.000 00	JP Morgan	0.20%	N/A
Series 15	5/23/2002	2.400.000.00	JP Morgan	0.20%	N/A
Series 16	10/3/2002	96.000,000 00	Citi Group, Bank of America	0.20%	N/A
Series 17	*10/20/2004*	*50.000.000 00*	*Merrill. Morgan Stanley*	0 35%	N/A
Series 18	7/7/2005	13.266.950 00	Bank of America	0 35%	N/A
Series 19	11/17/2005	13.266,950 00	Bank of America	0 35%	N/A
Series 20	7/20/2006	16.693,620.00	Citi Group	0.35%	N/A
Series 21	12/7/2006	16.693.620 00	Citi Group	0 35%	N/A
Series 21	12/7/2006	(16,693.620 00)			N/A
Series 22	2/23/2007	54.000,000 00	Bank of America/Lehman	0 35%	N/A
CC 2007A $17.8M	5/24/2007	17.875.000.00	Lehman	0 35%	N/A
TC 2007A $8.9M	5/24/2007	8,927,000.00	Lehman	0.35%	N/A
Total External Debt		$ 316,059,520.00			
Notes Payable to Fidelia Corp.	4/30/2003	$ 100,000,000.00			N/A
Notes Payable to Fidelia Corp	8/15/2003	75.000,000 00			N/A
Notes Payable to Fidelia Corp.	11/24/2003	33.000,000 00			N/A
Notes Payable to Fidelia Corp.	1/15/2004	50.000.000 00			N/A
Notes Payable to Fidelia Corp.	7/8/2005	50.000,000 00			N/A
Notes Payable to Fidelia Corp	12/19/2005	75.000.000.00			N/A
Notes Payable to Fidelia Corp.	*6/23/2006*	*50.000,000 00*			N/A
Notes Payable to Fidelia Corp.	10/25/2006	50.000,000 00			N/A
Notes Payable to Fidelia Corp.	2/7/2007	53,000,000 00			N/A
Notes Payable to Fidelia Corp.	3/30/2007	75.000,000 00			N/A
Notes Payable to Fidelia Corp	6/20/2007	50.000,000.00			N/A
Notes Payable to Fidelia Corp.	9/14/2007	100.000.000.00			N/A
Notes Payable to Fidelia Corp.	10/25/2007	70.000,000 00			N/A
Notes Payable to Fidelia Corp.	12/20/2007	100,000,000.00			N/A
Total Internal Debt		$ 931,000,000.00			
Total Long Term Debt		$ 1,247,059,520.00			

Short Term Debt

Payable to Associated Company (Money Pool)	N/A	$ 93,302,454.00

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 97

Responding Witness: William Steven Seelye

Q-97. Please provide a fully executable computerized copy of the KU jurisdictional cost of service study in Microsoft Excel format. In this response provide all linked files.

A-97. See response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 98

Responding Witness: William Steven Seelye

Q-98. Please provide a fully executable computerized copy of the KU class cost of service study in Microsoft Excel format. In this response provide all linked files.

A-98. See response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 99

Responding Witness: William Steven Seelye

Q-99. Please provide all industry manuals, academic articles, text books, and other authoritative sources supporting and discussing the "Modified Base-Intermediate-Peak" methodology utilized by Mr. Seelye. This request does not seek reference to the traditional Base-Intermediate-Peak method discussed for example, in the NARUC Electric Cost Allocation Manual, but rather the "modified" approach utilized by Mr. Seelye.

A-99. Mr. Seelye is unaware of any manuals, academic articles, text books, or other sources discussion the modified BIP methodology. The methodology was developed by LG&E in the early 1980s and has been accepted by the Commission in a number of rate cases as a guide for setting rates.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 100

Responding Witness: William Steven Seelye

Q-100. Please explain and provide all workpapers and spreadsheets showing the determination of the separation of Production plant between Base (33.58%); Intermediate (39.97%), and Peak (26.45%) implicit in KU Seelye Exhibit 18, page 1. In this response, explain the relevance or relationship with KU Seelye Exhibit 17. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-100. See response to PSC-2 Question No. 30 for the spreadsheet showing the determination of the separation of Production plant between Base (33.58%); Intermediate (39.97%), and Peak (26.45%) implicit in KU Seelye Exhibit 18, page 1. Seelye Exhibit 17 was used to time differentiate fixed costs in the cost of service study, and is incorporated as a functional vector on page 1 *et seq.* of Seelye Exhibit 18. A hardcopy of the BIP worksheet is included in Seelye Exhibit 17.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 101

Responding Witness: William Steven Seelye

Q-101. With regard to the class allocation of "Base" Production and Transmission Plant, please explain and reconcile the difference between allocator "BDEM" shown on KU Seelye Exhibit 19, page 49 (Rate RS is 0.352666) and the allocated percentages in Exhibit 19, page 1 for "Base" Production and Transmission Plant (Rate RS is 0.3503699).

A-101. There is no difference between the allocator "BDEM" shown on KU Seelye Exhibit 19, page 49 and the allocated percentages in Exhibit 19, page 1 for "Base" Production and Transmission Plant. For Rate RS, both allocators are 0.3503699.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 102

Responding Witness: William Steven Seelye

Q-102. With regard to Mr. Seelye's KU direct testimony, pages 54 and 56, Mr. Seelye refers to his class cost of service study as "time differentiated":

a. please explain and identify exactly the time periods that are differentiated, what costs are differentiated by time periods, and provide each time period's allocated costs;
b. the 12-CP allocates costs based on 12 monthly peak demands. Does Mr. Seelye consider the 12-CP method to be a time differentiated cost allocation methodology?;
c. Would Mr. Seelye consider an allocation method that allocates annual demand-related costs to classes based on the combined sum of the single Winter Peak and single Summer Peak demands to be time differentiated?; and,
d. Please define "time differentiated cost of service study" as used in standard industry practice.

A-102. a. The summer peak period is defined as weekdays from 10:00 a.m to 9:00 p.m., Eastern Standard Time. The winter peak period is defined as weekdays from 8:00 a.m. to 10:00 p.m., Eastern Standard Time. The off-peak period is defined as all other hours. Fixed production costs are assigned as summer peak period costs, winter peak period costs, or as non time differentiated.

b. Although Mr. Seelye has not encountered such a methodology, it may be possible to develop a time differentiated cost of service study that incorporates a 12-CP approach.

c. Although Mr. Seelye has not encountered such a methodology, it may be possible to develop a time differentiated cost of service study that allocates annual demand-related costs to classes based on the combined sum of the single Winter Peak and single Summer Peak demands.

d. A time differentiated cost of service study is a methodology that assigns a portion of a utility's costs to two or more costing periods. Although some methodologies are more appropriate than others, Mr. Seelye is unaware of there being a universally accepted methodology for preparing a time-differentiated cost of service study.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 103

Responding Witness: William Steven Seelye

Q-103. Please provide a detailed explanation or definition of each external and internal allocation and functionalization factor utilized in Mr. Seelye's KU jurisdictional and class cost of service studies.

A-103. External and internal functional vectors are fully described on pages 49 through 52 of Seelye Exhibit 18. External and internal allocation vectors are fully described on pages 49 through 54 of Seelye Exhibit 19.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 104

Responding Witness: William Steven Seelye

Q-104. Please provide all workpapers, source documents, and electronic spreadsheets showing the development of each external allocator (including functionalization factors) utilized in Mr. Seelye's KU jurisdictional and class cost of service studies. In this response, provide the source for all data and the bases for any weightings. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-104. See response to PSC-2 Question No. 30. The requested information is being provided on CD. Hard copies are not being provided due to the volume of the data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 105

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-105. For each KU and LG&E generating unit owned individually, jointly, or partially, please provide the following:

a. names of owners (and ownership percentages);
b. type and fuels;
c. total nameplate (rated) capacity (MW);
d. total and individual company gross investment at 4/30/08;
e. total and individual company depreciation reserve at 4/30/08;
f. total and individual company annual test year depreciation expense;
g. gross KWH produced during the test year; and,
h. net (less station use) KWH produced during the test year.

A-105. See attached.

Generating Unit	Owner	Ownership Percentage			Type	Fuels	Generator Nameplate Ratings (MW)	Generator Nameplate Ownership (MW)			KU Gross Investment 4/30/08	Total Gross Investment 4/30/08	KU Depr. Reserve 4/30/08	Total Depr. Reserve 4/30/08	Test Year Gross KWH Produced	Test Year Net KWH Produced
		KU	LGE	Other				KU	LGE	Other						
Brown 1	KU	100%			Conventional	Coal	114	114			$ 53,012,850.27	$ 53,012,850.27	$ (37,780,953.68)	$ (37,780,953.68)	515,058,000	468,905,000
Brown 2	KU	100%			Conventional	Coal	180	180			$ 43,715,823.84	$ 43,715,823.84	$ (30,006,199.69)	$ (30,006,199.69)	1,105,512,000	1,029,394,000
Brown 3	KU	100%			Conventional	Coal	446	446			$ 145,555,661.08	$ 145,555,661.08	$ (98,723,410.04)	$ (98,723,410.04)	2,733,782,000	2,563,918,000
Brown 5	Joint	47%	53%		Conventional	Gas	123.3	58	65		$ 20,988,561.86	$ 45,189,376.25	$ (4,647,474.76)	$ (10,117,593.17)	11,459,000	8,796,000
Brown 6	Joint	62%	38%		Conventional	Gas, Oil	177	110	67		$ 35,879,027.78	$ 58,867,791.66	$ (7,781,896.41)	$ (11,624,745.77)	56,294,000	53,883,000
Brown 7	Joint	62%	38%		Conventional	Gas, Oil	177	110	67		$ 35,821,754.67	$ 58,872,239.12	$ (7,077,078.71)	$ (13,429,374.42)	28,587,000	26,621,000
Brown 8	KU	100%			Conventional	Gas, Oil	126	126			$ 35,458,344.31	$ 35,458,344.31	$ (11,188,592.48)	$ (11,188,592.48)	23,577,000	21,554,000
Brown 9	KU	100%			Conventional	Gas, Oil	126	126			$ 45,866,272.01	$ 45,866,272.01	$ (20,153,159.16)	$ (20,153,159.16)	14,816,000	13,057,000
Brown 10	KU	100%			Conventional	Gas, Oil	126	126			$ 28,591,335.39	$ 28,591,335.39	$ (11,554,219.78)	$ (11,554,219.78)	8,377,000	6,510,000
Brown 11	KU	100%			Conventional	Gas, Oil	126	126			$ 43,496,658.93	$ 43,496,658.93	$ (14,669,594.73)	$ (14,669,594.73)	6,963,000	5,436,000
Cane Run 4	LGE		100%		Conventional	Coal	164		164							
Cane Run 5	LGE		100%		Conventional	Coal	209		209							
Cane Run 6	LGE		100%		Conventional	Coal	272		272							
Dix Dam 1	KU	100%			Conventional	Hydro	9	9			$ 11,033,232.19	$ 11,033,232.19	$ (8,291,935.19)	$ (8,291,935.19)	53,000,000	52,866,000
Dix Dam 2	KU	100%			Conventional	Hydro	9	9								
Dix Dam 3	KU	100%			Conventional	Hydro	9	9								
Ghent 1	KU	100%			Conventional	Coal	557	557			$ 341,334,639.79	$ 341,334,639.79	$ (204,717,999.69)	$ (204,717,999.69)	3,168,560,000	2,925,250,000
Ghent 2	KU	100%			Conventional	Coal	556	556			$ 148,051,935.70	$ 148,051,935.70	$ (112,136,974.70)	$ (112,136,974.70)	3,282,790,000	3,089,586,000
Ghent 3	KU	100%			Conventional	Coal	557	557			$ 490,571,473.06	$ 490,571,473.06	$ (211,623,209.68)	$ (211,623,209.68)	3,045,345,000	2,751,580,000
Ghent 4	KU	100%			Conventional	Coal	556	556			$ 365,800,075.84	$ 365,800,075.84	$ (174,602,024.16)	$ (174,602,024.16)	3,482,231,000	3,256,648,000
Green River 3	KU	100%			Conventional	Coal	75	75			$ 19,528,741.36	$ 19,528,741.36	$ (15,370,396.25)	$ (15,370,396.25)	484,211,000	446,792,000
Green River 4	KU	100%			Conventional	Coal	114	114			$ 42,267,632.98	$ 42,267,632.98	$ (32,196,931.06)	$ (32,196,931.06)	632,772,000	585,385,000
Haefling 1	KU	100%			Full Outdoor	Gas, Oil	21	21			$ 5,344,657.90	$ 5,344,657.90	$ (4,257,007.71)	$ (4,257,007.71)	74,000	(97,000)
Haefling 2	KU	100%			Full Outdoor	Gas, Oil	21	21							196,000	13,000
Haefling 3	KU	100%			Full Outdoor	Gas, Oil	21	21							82,000	(91,000)
Mill Creek 1	LGE		100%		Conventional	Coal	356		356							
Mill Creek 2	LGE		100%		Conventional	Coal	356		356							
Mill Creek 3	LGE		100%		Conventional	Coal	463		463							
Mill Creek 4	LGE		100%		Conventional	Coal	544		544							
Ohio Falls 1	LGE		100%		Conventional	Hydro	10		10							
Ohio Falls 2	LGE		100%		Conventional	Hydro	10		10							
Ohio Falls 3	LGE		100%		Conventional	Hydro	10		10							
Ohio Falls 4	LGE		100%		Conventional	Hydro	10		10							
Ohio Falls 5	LGE		100%		Conventional	Hydro	10		10							
Ohio Falls 6	LGE		100%		Conventional	Hydro	10		10							
Ohio Falls 7	LGE		100%		Conventional	Hydro	13		13							
Ohio Falls 8	LGE		100%		Conventional	Hydro	10		10							
Paddys Run 13	Joint	47%	53%		Conventional	Gas	178	84	94		$ 30,058,626.06	$ 64,097,928.37	$ (6,959,083.42)	$ (14,851,277.18)	25,077,000	25,077,000

Generating Unit	Owner	Ownership Percentage KU	LGE	Other	Type	Fuels	Generator Nameplate Ratings (MW)	Generator Nameplate Ownership (MW) KU	LGE	Other	KU Gross Investment 4/30/08	Total Gross Investment 4/30/08	KU Depr. Reserve 4/30/08	Total Depr. Reserve 4/30/08	Test Year Gross KWH Produced	Test Year Net KWH Produced
Trimble County 1	LGE		75%	25%	Conventional	Coal	566		425	141						
Trimble County 5	Joint	71%	29%		Conventional	Gas	199	141	58		$ 44,883,465.64	$ 63,318,703.61	$ (8,894,104.09)	$ (12,543,657.43)	83,318,000	83,318,000
Trimble County 6	Joint	71%	29%		Conventional	Gas	199	141	58		$ 39,704,318.41	$ 55,909,986.99	$ (7,863,621.10)	$ (11,073,718.68)	64,072,000	64,072,000
Trimble County 7	Joint	63%	37%		Conventional	Gas	199	125	74		$ 33,016,328.44	$ 52,341,310.84	$ (4,383,901.55)	$ (6,950,130.25)	65,245,000	65,245,000
Trimble County 8	Joint	63%	37%		Conventional	Gas	199	125	74		$ 32,777,316.64	$ 51,951,043.17	$ (4,352,133.41)	$ (6,898,257.97)	96,025,000	96,025,000
Trimble County 9	Joint	63%	37%		Conventional	Gas	199	125	74		$ 32,849,783.17	$ 52,051,641.66	$ (4,267,869.43)	$ (6,762,848.09)	87,217,000	87,217,000
Trimble County 10	Joint	63%	37%		Conventional	Gas	199	125	74		$ 32,854,273.55	$ 52,023,045.69	$ (4,107,134.56)	$ (6,497,712.31)	66,191,000	66,191,000
Tyrone 3	KU	100%			Conventional	Coal	75	75			$ 24,554,949.09	$ 24,554,949.09	$ (19,160,901.83)	$ (19,160,901.83)	491,789,000	455,347,000
Cane Run 11	LGE		100%		Conventional	Gas, Oil	16		16							
Paddy's Run 11	LGE		100%		Conventional	Gas	16		16							
Paddy's Run 12	LGE		100%		Conventional	Gas	33		33							
Zorn 1	LGE		100%		Conventional	Gas	18		18							

(1) Gross, net generation, investment, & depreciation reserve reported for Dix Dam 1 represents total plant. Generation is not reported on a per unit basis, and fixed asset costs are not accumulated on a per unit basis.

(2) Investment and Depreciation Reserve is shown for active units only. This does not include structural components still in place, land, and ARO costs associated with retired units.

(3) Depreciation expense is not tracked separately by unit. Total KU Production depreciation expense for the test year is:
Steam $49,562,470 Hydro $174,096 Other Production $16,624,788

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 106

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-106. Please provide the combined KU and LG&E generating order of dispatch by unit and basis for this order of dispatch.

A-106. Please see the dispatch merit order listed below. The dispatch merit order provided is based on unit assumptions at full load considering fuel and variable costs. Actual dispatch merit order is determined dynamically in the Energy Management System (EMS) based on heat rate curves and operating parameters for each unit.

TRIMBLE 1
SMITH 2
MILL CREEK 3
MILL CREEK 4
SMITH 1
MILL CREEK 1
MILL CREEK 2
GHENT 1
CANE RUN 6
GHENT 4
GHENT 3
CANE RUN 5
CANE RUN 4
BROWN 2
BROWN 3
BROWN 1
GHENT 2
GR RIVER 4
TYRONE 3
GR RIVER 3
TRIMBLE 5
TRIMBLE 6
TRIMBLE 7
TRIMBLE 8
TRIMBLE 9
TRIMBLE 10
BROWN 6
BROWN 7
DYNEGY CT
BROWN 8
BROWN 9
BROWN 10
BROWN 11
BROWN 5
PADDYS RUN 13
PADDYS RUN 11
CANE RUN 11
PADDYS RUN 12
ZORN 1
HAEFLING

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 107

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-107. For each KU and LG&E generating unit, please provide hourly gross and net output (peak or average MW or MWH) for the period 5/1/07 through 4/30/08. Please provide in hardcopy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-107. Please see the Microsoft Access database on the attached CD for the requested information, which is being provided pursuant to a Petition for Confidential Protection. Hardcopies are not provided due to the volume of data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 108

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-108. Please provide separately, KU and LG&E's hourly purchased power (MWH) by source for the period 5/1/07 through 4/30/08. In this response, exclude LG&E purchases from KU, and KU purchases from LG&E. Please provide in hardcopy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-108. See the response to Question No. 107.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 109

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-109. Please provide hourly sales from KU to LG&E for the period 5/1/07 through 4/30/07. Please provide in hardcopy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-109. See the response to Question No. 107.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 110

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-110. Please provide hourly sales from LG&E to KU for the period 5/1/07 through 4/30/08. Please provide in hardcopy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-110. See the response to Question No. 107.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 111

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-111. For each hour during the period 5/1/07 through 4/30/08, please provide the following:

a. total combined KU and LG&E system load (MW);
b. KU and LG&E total load (MW) separately;
c. KU native load (MW) (define native load);
d. LG&E native load (MW) (define native load);
e. KU non-native load (MW); and,
f. LG&E non-native load (MW).

Please provide in hardcopy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-111. See the response to Question No. 107. Part (b) is not available. Part (e) and (f) are for the combined system. Native load reflects requirements load served by the Companies for which resources are planned, consistent with Integrated Resource Planning.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 112

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-112. For each KU and LG&E generating unit, please provide all scheduled (planned) outages (dates, time, and duration) by unit for the period 5/1/07 through 4/30/08.

A-112. Please see the attachment for the period requested, consistent with information provided in the Company's Fuel Adjustment Clause proceedings. Note that all scheduled (planned) outages are indicated by; an "S" and include both planned and maintenance outages. All forced (unscheduled) outages are indicated by an "F".

Kentucky Utilities Company
E. W. Brown Unit 1 - Coal - 101 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	MAINTENANCE Scheduled TO	MAINTENANCE Actual FROM	MAINTENANCE Actual TO	HOURS OF DURATION Scheduled	HOURS OF DURATION Forced	HOURS OF DURATION Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	F			5/25/2007 22:11	5/27/2007 8:42		34:31		Economizer boiler tube failure
Jun-07	No Outages > or = 6 Hours								
Jul-07	No Outages > or = 6 Hours								
Aug-07	No Outages > or = 6 Hours								
Sep-07	S	9/15/2007 0:00	→	9/14/2007 20:58	→	384:00		387:02	Planned major turbine overhaul
Oct-07	S	→	→	→	→	744:00		744:00	" " " "
Nov-07	S		11/11/2007 15:00		11/18/2007 11:53	255:00		419:53	Planned major turbine overhaul
	F			11/18/2007 11:53	11/19/2007 16:00		28:07		Control issue: sensing line leak from steam drum
	F			11/19/2007 16:00	11/21/2007 6:58		38:58		Waterwall boiler tube failure
	F			11/21/2007 19:00	11/24/2007 6:44		59:44		Waterwall boiler tube failure
	S	11/24/2007 12:16	11/24/2007 20:57	11/24/2007 12:16	11/24/2007 20:57	8:41		8:41	Turbine vibration
	F			11/26/2007 14:35	11/28/2007 7:21		40:46		Control issue: deaerator level
Dec-07	F			12/8/2007 14:41	12/10/2007 2:18		35:37		Economizer boiler tube failure
	F			12/27/2007 12:09	12/28/2007 5:37		17:28		Reheat steam leak in line from cold reheat to deaerator
	F			12/28/2007 6:40	12/28/2007 13:02		6:22		Reheat steam leak in line from cold reheat to deaerator
	F			12/29/2007 16:47	12/30/2007 3:59		11:12		Precipitator - sections shorting out
Jan-08	No Outages > or = 6 Hours								
Feb-08	S	2/14/2008 8:51	2/14/2008 22:55	2/14/2008 8:51	2/14/2008 22:55	14:04		14:04	Precipitator repairs
	F			2/15/2008 3:15	2/15/2008 14:50		11:35		Opacity
Mar-08	S	3/14/2008 21:15	3/15/2008 22:58	3/14/2008 21:15	3/15/2008 22:58	25:43		25:43	Precipitator inspection and repairs
	F			3/16/2008 5:20	3/16/2008 20:15		14:55		Precipitator repairs
	F			3/21/2008 23:32	3/22/2008 15:46		16:14		Precipitator repairs
Apr-08	S	4/5/2008 0:00	4/13/2008 15:00	4/4/2008 22:30	4/12/2008 9:46	207:00		179:16	Planned outage for inspection and repairs on precipitator
	F			4/12/2008 12:48	4/13/2008 4:22		15:34		Precipitator grounded field
	F			4/13/2008 15:30	4/14/2008 21:49		30:19		Precipitator grounded field
	S	4/18/2008 21:12	4/21/2008 0:12	4/18/2008 21:12	4/21/2008 0:12	51:00		51:00	Precipitator repairs

Kentucky Utilities Company
E. W. Brown Unit 2 - Coal - 167 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	MAINTENANCE Scheduled TO	MAINTENANCE Actual FROM	MAINTENANCE Actual TO	HOURS OF DURATION Scheduled	HOURS OF DURATION Forced	HOURS OF DURATION Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	No Outages > or = 6 Hours								
Jun-07	F			6/9/2007 21:04	6/10/2007 22:28		25:24		Emergency generator trip devices
Jul-07	No Outages > or = 6 Hours								
Aug-07	No Outages > or = 6 Hours								
Sep-07	No Outages > or = 6 Hours								
Oct-07	S	10/26/2007 22:45	10/28/2007 3:50	10/26/2007 22:45	10/28/2007 3:50	29:05		29:05	High pressure heater tube leaks
Nov-07	S	11/24/2007 0:00	→	11/24/2007 1:37	→	168:00		166:23	Annual boiler inspection
Dec-07	S	→	12/16/2007 15:00	→	12/13/2007 17:42	375:00		305:42	" " "
	S	12/15/2007 0:21	12/15/2007 16:08	12/15/2007 0:21	12/15/2007 16:08	15:47		15:47	Generator vibration
Jan-08	No Outages > or = 6 Hours								
Feb-08	No Outages > or = 6 Hours								
Mar-08	No Outages > or = 6 Hours								
Apr-08	F			4/2/2008 18:05	4/4/2008 3:35		33:30		Waterwall boiler tube failure

Kentucky Utilities Company
E. W. Brown Unit 3 - Coal - 429 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	TO	Actual FROM	TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	S			→	5/3/2007 19:50			67:50	Annual boiler inspection
Jun-07	No Outages > or = 6 Hours								
Jul-07	No Outages > or = 6 Hours								
Aug-07	F			8/16/2007 16:52	8/17/2007 22:39		29:47		Transmission system problems
Sep-07	S	9/1/2007 23:32	9/3/2007 10:38	9/1/2007 23:32	9/3/2007 10:38	35:06		35:06	Condenser tube leaks
Oct-07	F			10/24/2007 22:53	10/25/2007 7:39		8:46		Generator main leads
Nov-07	No Outages > or = 6 Hours								
Dec-07	No Outages > or = 6 Hours								
Jan-08	F			1/13/2008 22:31	1/15/2008 2:16		27:45		Waterwall boiler tube failure
	F			1/31/2008 12:39	→		11:21		Cooling tower fan damage due to tornado
Feb-08	F			→	2/4/2008 22:42		94:42		" " " " " " "
Mar-08	No Outages > or = 6 Hours								
Apr-08	F			4/5/2008 10:43	4/6/2008 21:22		34:39		Generator current transformer repairs
	F			4/6/2008 22:17	4/7/2008 21:27		23:10		Generator current transformer failure
	F			4/7/2008 23:45	4/8/2008 16:19		16:34		Generator current transformer failure
	S	4/19/2008 0:00	→	4/21/2008 23:35	→	288:00		216:25	Annual boiler inspection and pulverizer mill outages

Kentucky Utilities Company
E. W. Brown 5 - Gas CT - 117 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	Scheduled TO	Actual FROM	Actual TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07		No Outages > or = 6 Hours							
Jun-07		No Outages > or = 6 Hours							
Jul-07	F			7/17/2007 10:08	7/26/2007 15:30		221:22		Gas fuel system - flame controls issues
Aug-07		No Outages > or = 6 Hours							
Sep-07		No Outages > or = 6 Hours							
Oct-07		No Outages > or = 6 Hours							
Nov-07		No Outages > or = 6 Hours							
Dec-07	F			12/18/2007 18:35	12/19/2007 11:20		16:45		Fire suppression CO_2 tank level showed empty
Jan-08		No Outages > or = 6 Hours							
Feb-08	S	2/28/2008 6:30	2/28/2008 13:20	2/28/2008 6:30	2/28/2008 13:20	6:50		6:50	Generator air cooling system - controls sensed moisture
Mar-08	S	3/11/2008 16:15	3/20/2008 13:27	3/11/2008 16:15	3/20/2008 13:27	213:12		213:12	Starting system
Apr-08		No Outages > or = 6 Hours							

Kentucky Utilities Company
E. W. Brown 6 - Gas CT - 154 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	TO	Actual FROM	TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	S	5/27/2007 5:30	5/27/2007 12:20	5/27/2007 5:30	5/27/2007 12:20	6:50		6:50	Low pressure blades/buckets
Jun-07	No Outages > or = 6 Hours								
Jul-07	S	7/21/2007 7:30	7/22/2007 10:00	7/21/2007 7:30	7/22/2007 10:00	26:30		26:30	Cooling and seal air system
Aug-07	No Outages > or = 6 Hours								
Sep-07	No Outages > or = 6 Hours								
Oct-07	S	10/13/2007 0:00	→	10/1/2007 5:30	→	456:00		738:30	Major gas turbine overhaul
Nov-07		→	11/25/2007 15:00	→	11/24/2007 6:27	591:00		558:27	Major gas turbine overhaul - for full load hot commissioning from vendor
	S	11/25/2007 1:16	11/25/2007 8:15	11/25/2007 1:16	11/25/2007 8:15	6:59		6:59	Turbine blading
	S	11/25/2007 13:14	11/28/2007 15:59	11/25/2007 13:14	11/28/2007 15:59	74:45		74:45	Remove outage temporary restrainer (from major overhaul)
	S	11/29/2007 23:53	11/30/2007 20:16	11/29/2007 23:53	11/30/2007 20:16	20:23		20:23	Continued full load hot commissioning activities
Dec-07	S	12/2/2007 2:46	12/5/2007 19:33	12/2/2007 2:46	12/5/2007 19:33	88:47		88:47	Continued full load hot commissioning activities
	S	12/7/2007 4:59	12/7/2007 19:16	12/7/2007 4:59	12/7/2007 19:16	14:17		14:17	Unit tripped due to vendor's logic change
	S	12/8/2007 18:15	12/9/2007 21:09	12/8/2007 18:15	12/9/2007 21:09	26:54		26:54	Continued full load hot commissioning activities
	S	12/11/2007 5:46	12/11/2007 14:11	12/11/2007 5:46	12/11/2007 14:11	8:25		8:25	Complete performance and emissions testing
	S	12/11/2007 16:38	12/20/2007 10:11	12/11/2007 16:38	12/20/2007 10:11	209:33		209:33	Final testing
Jan-08	F			1/3/2008 0:40	1/10/2008 9:44		177:04		Low pressure turbine fuel gas controls
Feb-08	F			2/13/2008 10:55	2/15/2008 14:25		51:30		Control issues
Mar-08	F			3/11/2008 8:35	3/11/2008 16:15		7:40		Starting system - closing coil on starting device main feed breaker shorted
Apr-08	S	4/29/2008 6:30	4/29/2008 13:15	4/29/2008 6:30	4/29/2008 13:15	6:45		6:45	Clean and inspect pre-mix air purge valves on fuel system

Kentucky Utilities Company
E. W. Brown 7 - Gas CT - 154 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE				HOURS OF DURATION			REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
		Scheduled		Actual					
		FROM	TO	FROM	TO	Scheduled	Forced	Actual	
May-07	S	5/27/2007 5:30	5/27/2007 11:40	5/27/2007 5:30	5/27/2007 11:40	6:10		6:10	Low pressure blades/buckets
Jun-07	F			6/15/2007 19:15	6/17/2007 14:00		42:45		Turning gear and motor
Jul-07	No Outages > or = 6 Hours								
Aug-07	F			8/7/2007 14:20	8/13/2007 8:00		137:40		Generator rotor collector rings
	F			8/30/2007 18:30	8/31/2007 15:25		20:55		Turning gear and motor
Sep-07	F			9/6/2007 15:12	9/14/2007 11:59		188:47		Gas turbine combustor issues - uneven temperature distribution
				9/14/2007 13:29	9/25/2007 15:42		266:13		Gas turbine combustor issues - uneven temperature distribution
				9/25/2007 16:13	9/26/2007 12:11		19:58		Gas turbine combustor issues - uneven temperature distribution
				9/26/2007 16:38	9/27/2007 14:27		21:49		Gas turbine combustor issues - uneven temperature distribution
				9/27/2007 18:52	9/28/2007 13:45		18:53		Gas turbine combustor issues - uneven temperature distribution
Oct-07	No Outages > or = 6 Hours								
Nov-07	No Outages > or = 6 Hours								
Dec-07	F			12/17/2007 7:05	12/17/2007 14:10		7:05		Fuel issue: unit tripped during fuel gas switchover
Jan-08	S	1/22/2008 12:00	1/23/2008 14:30	1/22/2008 12:00	1/23/2008 14:30	26:30		26:30	Boroscope inspection of low pressure turbine section
Feb-08	No Outages > or = 6 Hours								
Mar-08	F			3/11/2008 8:35	3/11/2008 16:15		7:40		Starting system - common closing coil on BR6 starting device main feed breaker had shorted
	S	3/26/2008 6:00	3/26/2008 13:00	3/26/2008 6:00	3/26/2008 13:00	7:00		7:00	Controls - bad transmitter
Apr-08	No Outages > or = 6 Hours								

Kentucky Utilities Company
E. W. Brown 8 - Gas CT - 106 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	Scheduled TO	Actual FROM	Actual TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	No Outages > or = 6 Hours								
Jun-07	No Outages > or = 6 Hours								
Jul-07	No Outages > or = 6 Hours								
Aug-07	No Outages > or = 6 Hours								
Sep-07	No Outages > or = 6 Hours								
Oct-07	No Outages > or = 6 Hours								
Nov-07	S	11/1/2007 9:00	11/1/2007 15:36	11/1/2007 9:00	11/1/2007 15:36	6:36		6:36	Generator output breaker leaking oil
Dec-07	No Outages > or = 6 Hours								
Jan-08	F			1/2/2008 10:31	1/7/2008 10:44		120:13		Inlet air vanes
Feb-08	No Outages > or = 6 Hours								
Mar-08	S	3/17/2008 7:05	3/17/2008 13:35	3/17/2008 7:05	3/17/2008 13:35	6:30		6:30	Compressor wash
Apr-08	S	4/14/2008 6:45	4/15/2008 13:07	4/14/2008 6:45	4/15/2008 13:07	30:22		30:22	Starting system

Kentucky Utilities Company
E. W. Brown 9 - Gas CT - 106 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	TO	Actual FROM	TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	No Outages > or = 6 Hours								
Jun-07	No Outages > or = 6 Hours								
Jul-07	No Outages > or = 6 Hours								
Aug-07	No Outages > or = 6 Hours								
Sep-07	No Outages > or = 6 Hours								
Oct-07	No Outages > or = 6 Hours								
Nov-07	No Outages > or = 6 Hours								
Dec-07	No Outages > or = 6 Hours								
Jan-08	F			1/26/2008 8:00	1/28/2008 12:55		52:55		Switchyard circuit breakers - hydraulics repair
Feb-08	No Outages > or = 6 Hours								
Mar-08	No Outages > or = 6 Hours								
Apr-08	S	4/14/2008 6:45	4/15/2008 13:07	4/14/2008 6:45	4/15/2008 13:07	30:22		30:22	Starting system

Schedule vs. Actual

Kentucky Utilities Company
E. W. Brown 10 - Gas CT - 106 MW
May 2007 through April 2008

MONTH	MAINTENANCE				HOURS OF DURATION			REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
	Scheduled		Actual					
	FROM	TO	FROM	TO	Scheduled	Forced	Actual	
May-07	No Outages > or = 6 Hours							
Jun-07	No Outages > or = 6 Hours							
Jul-07	No Outages > or = 6 Hours							
Aug-07	No Outages > or = 6 Hours							
Sep-07	No Outages > or = 6 Hours							
Oct-07	No Outages > or = 6 Hours							
Nov-07	No Outages > or = 6 Hours							
Dec-07	No Outages > or = 6 Hours							
Jan-08	No Outages > or = 6 Hours							
Feb-08	No Outages > or = 6 Hours							
Mar-08	No Outages > or = 6 Hours							
Apr-08	S 4/16/2008 6:00	4/17/2008 13:10	4/16/2008 6:00	4/17/2008 13:10	31:10		31:10	Starting system

Kentucky Utilities Company
E. W. Brown 11 - Gas CT - 106 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	TO	Actual FROM	TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	S	5/3/2007 18:30	5/9/2007 8:30	5/3/2007 18:30	5/9/2007 8:30	134:00		134:00	Generator metering devices
Jun-07	No Outages > or = 6 Hours								
Jul-07	No Outages > or = 6 Hours								
Aug-07	No Outages > or = 6 Hours								
Sep-07	No Outages > or = 6 Hours								
Oct-07	No Outages > or = 6 Hours								
Nov-07	No Outages > or = 6 Hours								
Dec-07	No Outages > or = 6 Hours								
Jan-08	S	1/8/2008 8:45	1/11/2008 11:30	1/8/2008 8:45	1/11/2008 11:30	74:45		74:45	Lube oil system - vibration in turbine jacking oil pump coupling
Feb-08	No Outages > or = 6 Hours								
Mar-08	No Outages > or = 6 Hours								
Apr-08	S	4/16/2008 6:00	4/17/2008 13:10	4/16/2008 6:00	4/17/2008 13:10	31:10		31:10	Starting system

Schedule vs. Actual

Kentucky Utilities Company
Ghent Unit 1 - Coal - 475 MW
May 2007 through April 2008

MONTH		MAINTENANCE Scheduled FROM	Scheduled TO	Actual FROM	Actual TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	No Outages > or = 6 Hours								
Jun-07	F			6/14/2007 6:37	6/14/2007 17:02		10:25		Switchyard system protection devices
	S	6/15/2007 23:46	6/17/2007 18:35	6/15/2007 23:46	6/17/2007 18:35	42:49		42:49	Induced draft fan - vibration
Jul-07	F			7/25/2007 13:46	7/29/2007 13:45		95:59		Slag and ash removal on boiler lower slope
Aug-07	No Outages > or = 6 Hours								
Sep-07	S	9/29/2007 0:00	→	9/28/2007 22:50	→	48:00		49:10	Planned major tubine overhaul
Oct-07	S	→	→	→	→	744:00		744:00	" " " "
Nov-07	S	→	12/2/2007 15:00	→	11/29/2007 21:59	759:00		693:59	Planned major tubine overhaul
	S	11/29/2007 22:59	11/30/2007 10:40	11/29/2007 22:59	11/30/2007 10:40	11:41		11:41	Pulverizer feeder control
Dec-07	F			12/7/2007 12:27	12/10/2007 8:58		68:31		Reheater slagging
Jan-08	F			1/6/2008 2:58	1/6/2008 13:54		10:56		Flue gas issues - induced draft and forced draft fans tripped during weekly test
Feb-08	S	2/9/2008 0:28	2/9/2008 23:31	2/9/2008 0:28	2/9/2008 23:31	23:03		23:03	Furnace wall boiler tube failure
	F			2/10/2008 18:48	2/13/2008 6:22		59:34		Condenser tube leaks
	S	2/15/2008 23:05	2/18/2008 1:38	2/15/2008 23:05	2/18/2008 1:38	50:33		50:33	Boiler drain valves leaking
Mar-08	F			3/11/2008 18:52	3/13/2008 4:41		33:49		Turbine miscellaneous turbine piping: blown expansion joint on the extraction line in neck of condenser
Apr-08	F			4/14/2008 18:00	4/15/2008 18:56		24:56		Circulating water piping
	F			4/15/2008 23:32	4/17/2008 7:25		31:53		Condenser tube leaks
	F			4/17/2008 15:35	4/18/2008 7:58		16:23		Boiler silica concentration high
	F			4/19/2008 7:13	4/19/2008 21:07		13:54		Boiler silica concentration high

Kentucky Utilities Company
Ghent Unit 2 - Coal - 484 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	TO	Actual FROM	TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	S	5/5/2007 0:00	5/20/2007 15:00	5/4/2007 19:41	5/19/2007 14:01	375:00		354:20	Planned spring outage
Jun-07	F			6/15/2007 23:39	6/16/2007 7:19		7:40		Switchyard system protection devices
Jul-07	S	7/20/2007 21:57	7/23/2007 2:32	7/20/2007 21:57	7/23/2007 2:32	52:35		52:35	High opacity emissions
Aug-07	F	No Outages > or = 6 Hours		8/24/2007 22:28	8/26/2007 21:14		46:46		Precipitator fouling
Sep-07									
Oct-07	S	10/26/2007 21:23	10/28/2007 19:00	10/26/2007 21:23	10/28/2007 19:00	45:37		45:37	High opacity emissions
	F			10/28/2007 19:00	10/30/2007 8:18		37:18		Service water piping
Nov-07	F			11/21/2007 9:40	11/24/2007 0:17		62:37		Generator field ground fault
Dec-07	S	12/24/2007 1:20	12/26/2007 2:29	12/24/2007 1:20	12/26/2007 2:29	49:09		49:09	Precipitator fouling
Jan-08	F			1/10/2008 7:25	1/12/2008 12:44		53:19		Precipitator fouling
Feb-08	F			2/1/2008 13:49	2/3/2008 16:02		50:13		Opacity
	F			2/10/2008 7:48	2/11/2008 6:25		22:37		Condenser tube leaks
	S			2/29/2008 23:39	⟶	0:00		0:21	Annual boiler inspection
Mar-08	S	3/1/2008 0:00	3/30/2008 15:00	⟶	3/29/2008 17:52	711:00		689:52	" " "
	F			3/29/2008 23:15	3/30/2008 19:14		19:59		Furnace wall waterwall boiler tube failure
Apr-08		No Outages > or = 6 Hours							

Kentucky Utilities Company
Ghent Unit 3 - Coal - 493 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	MAINTENANCE Scheduled TO	MAINTENANCE Actual FROM	MAINTENANCE Actual TO	HOURS OF DURATION Scheduled	HOURS OF DURATION Forced	HOURS OF DURATION Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	S			→	5/26/2007 14:20			614:20	Annual inspection and addition of flue gas desulfurization (FGD)
	F			5/27/2007 12:40	5/31/2007 5:04		88:24		Induced draft fan bearing
Jun-07	F			6/4/2007 18:07	6/9/2007 5:28		107:21		Flue gas desulfurization slurry in ID fan discharge ducts
	F			6/12/2007 23:21	6/15/2007 20:06		68:45		Primary superheater boiler tube failures
	F			6/16/2007 10:50	6/18/2007 0:27		37:37		Primary superheater boiler tube failures
Jul-07	No Outages > or = 6 Hours								
Aug-07	F			8/3/2007 6:19	8/7/2007 18:56		108:37		Boiler slag and ash removal
	F			8/11/2007 0:13	8/13/2007 15:08		62:55		Primary superheater boiler tube failures
	S	8/25/2007 22:36	8/26/2007 16:00	8/25/2007 22:36	8/26/2007 16:00	17:24		17:24	Boiler feed pump suction strainer
	F			8/26/2007 16:00	8/26/2007 23:49		7:49		Induced draft fan motor
Sep-07	S	9/7/2007 22:58	9/9/2007 23:31	9/7/2007 22:58	9/9/2007 23:31	48:33		48:33	Induced draft fan bearing
Oct-07	F			10/5/2007 9:56	10/7/2007 16:25		54:29		Primary superheater boiler tube failures
	F			10/7/2007 16:25	10/8/2007 21:54		29:29		Induced draft fan blade controls
Nov-07	F			11/2/2007 8:40	11/6/2007 4:07		91:27		Induced draft fans: blade sticking issues
Dec-07	S	12/10/2007 22:25	12/23/2007 13:57	12/10/2007 22:25	12/23/2007 13:57	303:32		303:32	Induced draft fans: replace bearings
Jan-08	S	1/26/2008 23:38	1/28/2008 20:54	1/26/2008 23:38	1/28/2008 20:54	45:16		45:16	Induced draft fans: excessive vibration
Feb-08	S	2/23/2008 0:37	2/24/2008 16:59	2/23/2008 0:37	2/24/2008 16:59	40:22		40:22	Induced draft fans: remove blanking plate
Mar-08	S	3/22/2008 23:46	3/23/2008 19:05	3/22/2008 23:46	3/23/2008 19:05	19:19		19:19	Secondary superheater slagging
	F			3/23/2008 19:05	3/24/2008 6:59		11:54		Startup failure due to one of ID fans not starting - limit switches were replaced
Apr-08	F			4/20/2008 0:19	4/21/2008 9:00		32:41		Economizer boiler tube failure
	F			4/21/2008 9:00	4/21/2008 23:19		14:19		Burners - work began during previous event--but did not finish when boiler tube failure was complete

Schedule vs. Actual

Kentucky Utilities Company
Ghent Unit 4 - Coal - 493 MW
May 2007 through April 2008

MONTH		MAINTENANCE				HOURS OF DURATION			REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
		Scheduled		Actual					
		FROM	TO	FROM	TO	Scheduled	Forced	Actual	
May-07		No Outages > or = 6 Hours							
Jun-07	F			6/18/2007 9:24	6/19/2007 23:31		38:07		Economizer boiler tube failure
Jul-07	S	7/13/2007 22:00	7/14/2007 16:58	7/13/2007 22:00	7/14/2007 16:58	18:58		18:58	Furnace waterwall boiler tube failure
Aug-07		No Outages > or = 6 Hours							
Sep-07	S	9/14/2007 23:07	9/16/2007 0:01	9/14/2007 23:07	9/16/2007 0:01	24:54		24:54	Furnace waterwall boiler tube failure
Oct-07		No Outages > or = 6 Hours							
Nov-07		No Outages > or = 6 Hours							
Dec-07	S	12/22/2007 0:09	12/24/2007 4:52	12/22/2007 0:09	12/24/2007 4:52	52:43		52:43	Precipitator fouling
Jan-08		No Outages > or = 6 Hours							
Feb-08		No Outages > or = 6 Hours							
Mar-08	F			3/24/2008 3:19	3/26/2008 21:18		65:59		SO_2 stack emissions - rose above compliance levels
Apr-08	S	4/5/2008 0:00	→	4/5/2008 1:47	→	624:00		622:13	Major turbine overhaul

Kentucky Utilities Company
Green River Unit 3 - Coal - 68 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	Scheduled TO	Actual FROM	Actual TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	No Outages > or = 6 Hours								
Jun-07	F			6/18/2007 11:18	6/19/2007 18:30		31:12		Primary superheater boiler tube failure
	F			6/21/2007 17:33	6/22/2007 19:55		26:22		Environmental permits - extremely low river levels
Jul-07	S	7/7/2007 2:34	7/7/2007 17:00	7/7/2007 2:34	7/7/2007 17:00	14:26		14:26	Main transformer - high temps
Aug-07	No Outages > or = 6 Hours								
Sep-07	S	9/15/2007 11:30	9/15/2007 20:33	9/15/2007 11:30	9/15/2007 20:33	9:03		9:03	Boiler drains - plugged valves
	S	9/16/2007 7:00	9/17/2007 19:30	9/16/2007 7:00	9/17/2007 19:30	36:30		36:30	Furnace waterwall boiler tube failure
Oct-07	No Outages > or = 6 Hours								
Nov-07	No Outages > or = 6 Hours								
Dec-07	F			12/17/2007 21:26	12/19/2007 22:25		48:59		Furnace wall waterwall boiler tube failure
	F			12/19/2007 22:25	12/20/2007 5:16		6:51		Chemical addition systems: phosphate pump failure
Jan-08	F			1/17/2008 4:01	1/17/2008 12:57		8:56		Burner management system - UPS failure
Feb-08	F			2/4/2008 10:23	2/4/2008 16:42		6:19		DC failure on unit due to switching error
	F			2/11/2008 0:10	2/13/2008 1:44		49:34		Boiler tube failure
	S	2/22/2008 22:27	2/24/2008 5:21	2/22/2008 22:27	2/24/2008 5:21	30:54		30:54	Induced draft fans: high vibration
Mar-08	F			3/1/2008 11:18	3/2/2008 5:04		17:46		Boiler tube failure
Apr-08	F			4/15/2008 15:27	4/17/2008 16:03		48:36		Furnace waterwall boiler tube failure

Schedule vs. Actual

Kentucky Utilities Company
Green River Unit 4 - Coal - 95 MW
May 2007 through April 2008

MONTH		MAINTENANCE Scheduled FROM	Scheduled TO	Actual FROM	Actual TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	S	4/28/2007 0:00	5/6/2007 15:00	5/2/2007 23:52	5/6/2007 8:40	207:00		80:48	Planned boiler overhaul
Jun-07	F			6/2/2007 5:02	6/2/2007 11:40		6:38		Turbine main stop valve testing
Jul-07	No Outages > or = 6 Hours								
Aug-07	S	8/25/2007 22:57	8/26/2007 23:12	8/25/2007 22:57	8/26/2007 23:12	24:15		24:15	Furnace waterwall boiler tube failure
Sep-07	No Outages > or = 6 Hours								
Oct-07	F			10/14/2007 1:23	10/15/2007 3:05		25:42		Furnace waterwall boiler tube failure
Nov-07	S	11/3/2007 0:00	⟶	11/3/2007 23:40	⟶	672:00		648:20	Annual boiler inspection
Dec-07	S	⟶	12/2/2007 15:00	⟶	12/2/2007 7:00	39:00		31:00	" " "
	F			12/2/2007 7:00	12/2/2007 18:47		11:47		Turbine drain line header leak
	F			12/3/2007 22:22	12/4/2007 9:56		11:34		Reheat dump valve leak
	F			12/5/2007 14:12	12/6/2007 19:40		29:28		Second superheater boiler tube failure
	F			12/7/2007 21:59	12/8/2007 6:47		8:48		Reheat dump valve leak
	F			12/22/2007 21:52	12/25/2007 2:40		52:48		Furnace wall boiler tube failure
	F			12/25/2007 2:40	12/26/2007 14:45		36:05		Turbine drain line header leak
	F			12/26/2007 14:45	12/27/2007 1:45		11:00		Turbine drain line header leak
Jan-08	No Outages > or = 6 Hours								
Feb-08	S	2/15/2008 23:55	2/17/2008 9:13	2/15/2008 23:55	2/17/2008 9:13	33:18		33:18	Secondary superheater boiler tube failure
Mar-08	S	3/22/2008 0:35	3/23/2008 3:04	3/22/2008 0:35	3/23/2008 3:04	26:29		26:29	Secondary superheater boiler tube failure
Apr-08	F			4/1/2008 12:53	4/2/2008 16:24		27:31		Secondary superheater boiler tube failure
	F			4/15/2008 22:10	4/17/2008 9:32		35:22		Secondary superheater boiler tube failure
	F			4/29/2008 22:29	4/30/2008 21:20		22:51		Secondary superheater boiler tube failure

Kentucky Utilities Company
Haefling 1 - Gas CT - 12 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE				HOURS OF DURATION			REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
		Scheduled		Actual					
		FROM	TO	FROM	TO	Scheduled	Forced	Actual	
May-07	No Outages > or = 6 Hours								
Jun-07	No Outages > or = 6 Hours								
Jul-07	F			7/27/2007 11:51	7/31/2007 9:21		93:30		Gas turbine control system logic
Aug-07	F			8/8/2007 13:48	8/9/2007 15:33		25:45		Engine exhaust temperature high
	F			8/9/2007 15:36	8/15/2007 14:02		142:26		Gas turbine controls - ground
	F			8/15/2007 14:15	8/16/2007 18:18		28:03		Engine exhaust temperature high
Sep-07	S	9/6/2007 7:20	9/7/2007 10:37	9/6/2007 7:20	9/7/2007 10:37	27:17		27:17	Gas turbine controls - wiring
Oct-07	F			10/8/2007 12:18	→		563:42		Gas turbine control system logic
Nov-07	F			→	11/15/2007 11:15		347:15		Gas turbine control system logic
Dec-07	No Outages > or = 6 Hours								
Jan-08	No Outages > or = 6 Hours								
Feb-08	No Outages > or = 6 Hours								
Mar-08	No Outages > or = 6 Hours								
Apr-08	No Outages > or = 6 Hours								

Kentucky Utilities Company
Haefling 2 - Gas CT - 12 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH	MAINTENANCE				HOURS OF DURATION			REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
	Scheduled		Actual					
	FROM	TO	FROM	TO	Scheduled	Forced	Actual	
May-07	No Outages > or = 6 Hours							
Jun-07	No Outages > or = 6 Hours							
Jul-07	No Outages > or = 6 Hours							
Aug-07	No Outages > or = 6 Hours							
Sep-07	No Outages > or = 6 Hours							
Oct-07	No Outages > or = 6 Hours							
Nov-07	No Outages > or = 6 Hours							
Dec-07	No Outages > or = 6 Hours							
Jan-08	No Outages > or = 6 Hours							
Feb-08	No Outages > or = 6 Hours							
Mar-08	No Outages > or = 6 Hours							
Apr-08	No Outages > or = 6 Hours							

Kentucky Utilities Company
Haefling 3 - Gas CT - 12 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	MAINTENANCE Scheduled TO	MAINTENANCE Actual FROM	MAINTENANCE Actual TO	HOURS OF DURATION Scheduled	HOURS OF DURATION Forced	HOURS OF DURATION Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	No Outages > or = 6 Hours								
Jun-07	No Outages > or = 6 Hours								
Jul-07	F			7/27/2007 11:51	7/31/2007 9:39		93:48		Gas turbine control system logic
Aug-07	F			8/6/2007 13:03	8/7/2007 6:10		17:07		Lube oil system
	F			8/8/2007 13:45	8/9/2007 15:45		26:00		High engine exhaust temperatures
	F			8/15/2007 13:10	8/16/2007 12:00		22:50		Lube oil coolers
	F			8/16/2007 19:09	8/17/2007 7:00		11:51		High engine exhaust temperatures
	S	8/17/2007 7:00	→	8/17/2007 7:00	→	353:00		353:00	Cooling water system
Sep-07	S	→	9/5/2007 7:08	→	9/5/2007 7:08	103:08		103:08	" " "
Oct-07	F			10/8/2007 13:16	10/9/2007 7:09		17:53		Lube oil coolers
Nov-07	No Outages > or = 6 Hours								
Dec-07	No Outages > or = 6 Hours								
Jan-08	No Outages > or = 6 Hours								
Feb-08	No Outages > or = 6 Hours								
Mar-08	No Outages > or = 6 Hours								
Apr-08	No Outages > or = 6 Hours								

Kentucky Utilities Company
Tyrone Unit 3 - Coal - 71 MW
May 2007 through April 2008

Schedule vs. Actual

MONTH		MAINTENANCE Scheduled FROM	Scheduled TO	Actual FROM	Actual TO	HOURS OF DURATION Scheduled	Forced	Actual	REASON FOR DEVIATION FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE AS APPROPRIATE
May-07	F			5/1/2007 8:05	5/2/2007 21:57		37:52		Primary superheater boiler tube failure
Jun-07	S	6/29/2007 21:02	→	6/29/2007 21:02	→	26:58		26:58	Precipitator field out
Jul-07	S	→	7/1/2007 20:52	→	7/1/2007 20:52	20:52		20:52	" " "
Aug-07	No Outages > or = 6 Hours								
Sep-07	No Outages > or = 6 Hours								
Oct-07	No Outages > or = 6 Hours								
Nov-07	No Outages > or = 6 Hours								
Dec-07	S	12/31/2007 8:00	12/31/2007 22:39	12/31/2007 8:00	12/31/2007 22:39	14:39		14:39	Attemperator valve leaking
Jan-08	F			1/23/2008 17:39	1/26/2008 6:29		60:50		Generator rotor collector ring brushes failed
Feb-08	No Outages > or = 6 Hours								
Mar-08	No Outages > or = 6 Hours								
Apr-08	No Outages > or = 6 Hours								

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 113

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-113. For each KU and LG&E generating unit, please provide all forced (unscheduled) outages (dates, time, and duration) by unit for the period 5/1/07 through 4/30/08.

A-113. See the response to Question No. 112.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 114

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-114. Please identify and explain any events or circumstance occurring during the test year that materially (significantly) altered the normal (typical) economic dispatch of LG&E's and KU's electric Production resources (if any).

A-114. Besides the scheduled and forced outages identified in response to Question No. 112 and Question No. 113, the Company is unaware of any events or circumstances occurring during the test year that materially altered the economic dispatch of the generation resources.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 115

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-115. For each KU and LG&E generating unit, please provide average annual fuel cost per KWH and average annual variable running costs (lambda) for the period 5/1/07 through 4/30/08. Note: If this exact period is unavailable, the most recent available 12-month period may be used (specify time period).

A-115. Hourly system lambda data for the test year are included in an Excel spreadsheet provided on CD. Because KU and LG&E's generation resources (as well OMU resources) are jointly dispatched, the system lambda data cannot be separated between KU and LG&E resources. Lambda data does not exist by generating unit.

Estimated hourly fuel and total energy costs (fuel and variable operation and maintenance expenses) by unit and for the total system for KU and LG&E are included in an Access data base provided on CD pursuant to a Petition for Confidential Protection.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 116

Responding Witness: William Steven Seelye

Q-116. Please provide a copy of the most recent KU line-loss study, or KU and LG&E combined, as available.

A-116. See response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 117

Responding Witness: William Steven Seelye

Q-117. Please specifically explain and define how KU distinguishes between primary and secondary voltage; e.g., voltage level.

A-117. Primary and secondary voltages are shown on the proposed P.S.C. No. 14, Original Sheet No. 99, as provided in Tab 8, Volume I of the Statutory Notice, Application, Financial Exhibit, Table of Contents, Filing Requirements filed with the Commission on July 29, 2008.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 118

Responding Witness: William Steven Seelye

Q-118. Please provide a copy of the most recent KU class load study including all supporting tables, schedules, and data.

A-118. The requested information is being provided on CD.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 119

Responding Witness: William Steven Seelye

Q-119. Please provide all workpapers, analyses, calculations, etc. supporting all KU non-jurisdictional and jurisdictional class demands (loads) utilized in the jurisdictional and class cost of service studies. In this response, please explain and indicate how class demands were specifically determined or estimated. Include all definitions of demand utilized e.g., CP, NCP and sum of individual customers. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-119. The requested information is being provided on CD. Hard copies are not being provided due to the volume of the data requested.

KU's class load profiles were developed based on interval data from its load research survey. Simple and stratified random sampling techniques were utilized to develop class load profiles for the majority of the residential and commercial classes. Census samples were utilized to develop class load profiles for most of the industrial classes.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 120

Responding Witness: William Steven Seelye

Q-120. For each KU substation, please provide hourly demands (maximum load) for the period 5/1/07 through 4/30/08. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-120. The requested information is being provided on CD. Hard copies are not being provided due to the volume of the data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 121

Responding Witness: William Steven Seelye

Q-121. For each KU substation dedicated to specific native load customer(s) or non-native load customer(s), please identify each substation and the type of dedicated customer served by the substation; i.e., rate schedules, customer name, and non-jurisdictional/jurisdictional.

A-121. See attached. None of KU's substations are dedicated to specific customers. The attached document provides the requested information for KU substations currently serving single customers.

SubID	Plan	Plan Description	Jurisdictional/Non-Jurisdictional
1595	568	LP Sec PF Ky	Jurisdictional
2205	563	LCI-TOD Pri PF	Jurisdictional
2215	563	LCI-TOD Pri PF	Jurisdictional
3102	551	LP Pri Va	Jurisdictional
3691	853	Company Use Substations	Jurisdictional
3751	110	GS Sec Urban	Jurisdictional
3861	110	GS Sec Urban	Jurisdictional
4121	563	LCI-TOD Pri PF	Jurisdictional
4181	853	Company Use Substations	Jurisdictional
4301	686	MP Pri PF	Jurisdictional
4421	853	Company Use Substations	Jurisdictional
4431	902	Municipal Pri	Non-Jurisdictional
4451	561	LP Pri Ky	Jurisdictional
4531	902	Municipal Pri	Non-Jurisdictional
4751	563	LCI-TOD Pri PF	Jurisdictional
4761	686	MP Pri PF	Jurisdictional
4932	853	Company Use Substations	Jurisdictional
5251	855	Company Use Meters	Jurisdictional
5301	902	Municipal Pri	Non-Jurisdictional
5351	563	LCI-TOD Pri PF	Jurisdictional
5441	686	MP Pri PF	Jurisdictional
5471	566	LP Pri PF Ky	Jurisdictional
5481	852	Company Use Information	Jurisdictional
5501	853	Company Use Substations	Jurisdictional
5601	111	GS Pri Urban	Jurisdictional
5831	853	Company Use Substations	Jurisdictional
5931	902	Municipal Pri	Non-Jurisdictional
6061	853	Company Use Substations	Jurisdictional
6161	902	Municipal Pri	Non-Jurisdictional
6192	902	Municipal Pri	Non-Jurisdictional
6221	686	MP Pri PF	Jurisdictional
6291	853	Company Use Substations	Jurisdictional
6321	853	Company Use Substations	Jurisdictional
6581	110	GS Sec Urban	Jurisdictional
6611	111	GS Pri Urban	Jurisdictional
6791	110	GS Sec Urban	Jurisdictional
7111	853	Company Use Substations	Jurisdictional
7151	853	Company Use Substations	Jurisdictional
7191	566	LP Pri PF Ky	Jurisdictional
7331	566	LP Pri PF Ky	Jurisdictional
7411	683	LMP-TOD Pri PF	Jurisdictional
7461	110	GS Sec Urban	Jurisdictional
7491	687	MP Trans PF	Jurisdictional
7551	902	Municipal Pri	Non-Jurisdictional
7961	902	Municipal Pri	Non-Jurisdictional
8161	902	Municipal Pri	Non-Jurisdictional
8251	563	LCI-TOD Pri PF	Jurisdictional
8401	566	LP Pri PF Ky	Jurisdictional
8771	686	MP Pri PF	Jurisdictional

8861	110 GS Sec Urban	Jurisdictional
8871	902 Municipal Pri	Non-Jurisdictional
8891	566 LP Pri PF Ky	Jurisdictional
8901	110 GS Sec Urban	Jurisdictional

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 122

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-122. Please explain in detail and itemize individual "Other Taxes" included in KU Seelye Exhibit 19 page 25.

A-122. Other taxes include the following components:

Unemployment taxes	$	221,739
FICA		5,019,479
PSC Fee		1,769,547
Miscellaneous		(246,800)
	$	6,763,965

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 123

Responding Witness: William Steven Seelye

Q-123. Please explain what "Gain Disposition of Allowances" specifically represents on KU Seelye Exhibit 19, page 28 and why it is classified as Production Base-Energy.

A-123. The gain on disposition of allowances results from the approximately 2.8% of allowances allocated to KU each year and sold through the U.S. EPA allowance auction in March. Because these costs are ultimately related to the amount of energy, they were functionally assigned as Production Base – Energy, which is allocated on the basis of an energy allocator.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 124

Responding Witness: William Steven Seelye

Q-124. Please explain what "Merger Surcredit Amortization" represents on KU Seelye Exhibit 19, page 34, as well as the detailed basis for class assignment.

A-124. The Merger Surcredit Amortization is the amortization of a lump-sum payment made to certain customers in lieu of monthly surcredit payments.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 125

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-125. Please provide details for "Miscellaneous Service Revenues" totaling $1,578,059 on KU Seelye Exhibit 19, page 34.

A-125. The following is a breakdown of Miscellaneous Service Revenue:

Reconnection Charges	$1,079,166
Temporary Services	74,026
Other Service Revenue	127,543
Refundable Advances	297,324
Total	$1,578,059

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 126

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-126. Please provide details for "Rent From Electric Property" totaling $1,994,812 on KU Seelye Exhibit 19, page 34.

A-126. The following is a breakdown of Rent From Electric Property:

CATV Attachment	$ 443,294
Other Rent-Electric Property	1,433,429
Rent from Fiber Optics	118,089
Total	$ 1,994,812

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 127

Responding Witness: William Steven Seelye

Q-127. Please explain how interruptible (curtailment rider) customers' demands and energy usage are reflected in the KU class cost of service study.

A-127. Interruptible customers' actual energy usages were used to develop the energy allocation factors. In the cost of service study, the customers' summer CP demands were adjusted to reflect levels that would have occurred had the customers not been interrupted. The customers' winter CP demands were unadjusted.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 128

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-128. With regard to KU Curtailment Service Rider 1 ("CSR1"), please provide the following amounts by rate schedule, separated between Primary and Transmission, for each month of the test year:

a. number of customers;
b. total firm contract demand;
c. total contract curtailment load;
d. total billing demand;
e. total demand credits;
f. total non-compliance charges by month; and,
g. listing of date, time, duration, and estimated MW curtailment.

Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-128. The Company has no transmission customers served by this rate schedule.

a-f. See attached for primary customer information.

g. See attached for primary customer information.

Kentucky Utilities Company
Case No. 2008-00251
Curtailment Service Rider 1 (CSR1)
For the Test Year Ending April 30, 2008

	Number of Customers	Total Firm Contract Demand (KW)	Total Contract Curtailment Load (KW)	Total Billing Demand (KW)	Total Demand Credits	Total Non-Compliance Charges
	(a)	(b)	(c)	(d)	(e)	(f)
May-07	1	200	3,100	2,859.8	$ (8,511.36)	$ -
Jun-07	1	200	3,100	2,776.3	(8,244.16)	-
Jul-07	1	200	3,100	2,668.3	(7,898.56)	-
Aug-07	1	200	3,100	2,715.8	(8,050.56)	-
Sep-07	1	200	3,100	2,724.5	(8,078.40)	-
Oct-07	1	200	3,100	2,662.6	(7,880.32)	-
Nov-07	1	200	3,100	2,805.1	(8,336.32)	-
Dec-07	1	200	3,100	2,528.6	(7,451.52)	-
Jan-08	1	200	3,100	2,501.3	(7,364.16)	-
Feb-08	1	200	3,100	2,792.2	(8,295.04)	-
Mar-08	1	200	3,100	2,658.2	(7,866.24)	-
Apr-08	1	200	3,100	2,805.1	(8,336.32)	-

Kentucky Utilities Company
Case No. 2008-00251
Curtailment Service Rider 1 (CSR1)
For the Test Year Ending April 30, 2008

Start Date	Start Time	End Date	End Time	Duration in Hours	Estimated MW Curtailment Charges
05/10/07	13:00	05/10/07	21:00	8.00	-
07/09/07	10:00	07/09/07	15:00	5.00	-
07/10/07	10:00	07/10/07	15:00	5.00	-
07/19/07	10:00	07/19/07	15:00	5.00	-
08/06/07	12:00	08/06/07	15:00	3.00	-
08/07/07	12:00	08/07/07	15:00	3.00	-
08/08/07	12:00	08/08/07	15:00	3.00	-
08/09/07	12:00	08/09/07	15:00	3.00	-
08/10/07	12:00	08/10/07	15:00	3.00	-
08/13/07	12:00	08/13/07	15:00	3.00	-
08/14/07	11:00	08/14/07	15:00	4.00	-
08/15/07	12:15	08/15/07	15:00	2.75	-
08/16/07	12:00	08/16/07	15:00	3.00	-
08/23/07	11:00	08/23/07	20:00	9.00	-
08/24/07	12:00	08/24/07	17:00	5.00	-

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 129

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-129. With regard to KU Curtailment Service Rider 2 ("CSR2"), please provide the following amounts by rate schedule, separated between Primary and Transmission, for each month of the test year:

a. number of customers;
b. total firm contract demand;
c. total contract curtailment load;
d. total billing demand;
e. total demand credits;
f. total non-compliance charges by month; and,
g. listing of date, time, duration, and estimated MW curtailment.

Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-129. a-g. The Company did not have any customers subject to the Curtailment Service Rider 2 within the test year.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 130

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-130. With regard to KU Curtailment Service Rider 3 ("CSR3"), please provide the following amounts by rate schedule, separated between Primary and Transmission, for each month of the test year:

a. number of customers;
b. total firm contract demand;
c. total contract curtailment load;
d. total billing demand;
e. total demand credits;
f. total non-compliance charges; and,
g. listing of date, time, duration, and estimated MW curtailment.

Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-130. The Company has no primary customers served by this rate schedule.

a-f. See attached for transmission customer information.

g. See attached for transmission customer information.

Kentucky Utilities Company
Case No. 2008-00251
Curtailment Service Rider 3 (CSR3)
For the Test Year Ending April 30, 2008

	Number of Customers (a)	Total Firm Contract Demand (KVA) (b)	Total Contract Curtailment Load (c)	Total Billing Demand (d)	Total Demand Credits (e)	Total Non-Compliance Charges (f)
May-07	1	4,000	148,000	272,238.1	$ 452,370.91	$ -
Jun-07	1	4,000	148,000	238,695.4	418,543.09	-
Jul-07	1	4,000	148,000	256,644.5	437,501.14	-
Aug-07	1	4,000	148,000	299,116.7	464,878.79	-
Sep-07	1	4,000	148,000	290,727.2	460,768.81	-
Oct-07	1	4,000	148,000	249,512.5	458,178.45	-
Nov-07	1	4,000	148,000	243,946.9	444,656.87	-
Dec-07	1	4,000	148,000	248,900.8	460,859.02	-
Jan-08	1	4,000	148,000	253,298.2	463,009.18	-
Feb-08	1	4,000	148,000	259,636.2	466,451.73	-
Mar-08	1	4,000	148,000	298,010.4	464,468.97	-
Apr-08	1	4,000	148,000	299,126.8	454,605.08	-

Kentucky Utilities Company
Case No. 2008-00251
Curtailment Service Rider 3 (CSR3)
For the Test Year Ending April 30, 2008

Start Date	Start Time	End Date	End Time	Duration in Hours	Estimated MW Curtailment Charges
07/03/07	13:25	07/03/07	18:00	4.58	-
07/06/07	12:40	07/06/07	13:15	0.58	-
07/09/07	15:15	07/09/07	18:00	2.75	-
08/03/07	20:10	08/03/07	21:00	0.83	-
08/15/07	12:15	08/15/07	18:35	6.33	-
08/16/07	17:32	08/16/07	18:45	1.22	-
10/11/07	18:54	10/11/07	20:34	1.67	-
10/15/07	18:20	10/15/07	19:40	1.33	-
10/19/07	18:40	10/19/07	19:45	1.08	-
10/22/07	11:30	10/22/07	12:40	1.17	-
10/24/07	15:30	10/24/07	16:55	1.42	-
11/16/07	19:15	11/16/07	21:00	1.75	-
11/21/07	10:30	11/21/07	11:30	1.00	-
11/27/07	18:10	11/27/07	20:00	1.83	-
11/28/07	19:05	11/28/07	19:45	0.67	-
11/29/07	18:50	11/29/07	19:30	0.67	-
12/11/07	18:20	12/11/07	19:00	0.67	-
01/10/08	11:35	01/10/08	13:15	1.67	-
01/15/08	18:20	01/15/08	19:10	0.83	-
01/23/08	17:30	01/23/08	18:30	1.00	-
02/04/08	10:52	02/04/08	11:52	1.00	-
02/06/08	18:36	02/06/08	19:10	0.57	-
02/08/08	14:40	02/08/08	15:40	1.00	-
02/27/08	18:00	02/27/08	20:00	2.00	-
03/17/08	19:15	03/17/08	20:00	0.75	-
03/19/08	20:09	03/19/08	21:40	1.52	-
03/20/08	19:48	03/20/08	20:30	0.70	-
03/26/08	8:00	03/26/08	12:30	4.50	-
03/26/08	14:10	03/26/08	17:25	3.25	-
03/28/08	19:42	03/28/08	21:12	1.50	-
03/31/08	19:00	03/31/08	21:00	2.00	-
04/04/08	20:47	04/04/08	21:25	0.63	-

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 131

Responding Witness: William Steven Seelye

Q-131. With regards to Curtailable Service Rider credits and avoided costs shown in KU Seelye Exhibit 19, page 34 through 36:

a. please explain what the <$2,040,216> of "Curtailable Service Rider Avoided Cost" represents and provide all workpapers showing the determination of this amount;

b. please explain and provide all workpapers, spreadsheets, source documents, and analyses showing how the "specific assignments" were made to individual classes;

c. please explain why the specific assignment of avoided costs to Combined Light & Power (CPP) is positive, while all other classes receiving a direct assignment are negative; and,

d. please explain the basis and provide all workpapers and spreadsheets showing how the allocation of Curtailable Service Rider Credits were made e.g., the development of allocation vector "INTCRE."

A-131. a. The $2,040,216 "Curtailable Service Rider Avoided Cost" represents the avoided cost associated with interruptible service. The workpapers are provided in the PSC-2 Question No. 30.

b. The specific assignments were made by multiplying the curtailable load by the avoided costs. This calculation is shown in the cost of service study provided in the response to PSC-2 Question No. 30.

c. The positive amount represents an avoided cost credit, while the negative amount spreads the avoided costs to all customer classes to result in a zero-sum impact

d. The "INTCRE" allocation factor represents the sum of the winter and summer fixed production plant. This calculation is shown in the cost of service study provided in the response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 132

Responding Witness: William Steven Seelye

Q-132. Please provide KU distribution transformer investment and number of units separated between primary and secondary voltage.

A-132. KU's records do not record transformer investment separated between primary and secondary voltages.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 133

Responding Witness: William Steven Seelye

Q-133. Please provide a list of KU distribution transformers by type and capacity that are currently being installed, separated by primary system and secondary system.

A-133. KU's records do not record distribution transformers separated between primary and secondary voltages.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 134

Responding Witness: William Steven Seelye

Q-134. Please provide a list of KU distribution overhead conductor types and sizes currently being installed (typical), separated by primary system and secondary system.

A-134. See response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 135

Responding Witness: William Steven Seelye

Q-135. With respect to Mr. Seelye's zero-intercept analysis for KU underground conductors (Exhibit 21), please explain why the customer/demand classification was not used in the class cost of service study (Exhibits 18 and 19).

A-135. The customer/demand classification was used in the class cost of service study.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 136

Responding Witness: William Steven Seelye

Q-136. Please explain why Mr. Seelye combined all distribution conductors (primary and secondary) for KU classification purposes.

A-136. Mr. Seelye did not combine all distribution conductors for KU classification purposes.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 137

Responding Witness: William Steven Seelye

Q-137. Please provide the number of customer bills by rate schedule during the test year with annual energy usage less than 500 KWH.

A-137. The requested information is not available in a readily reproducible form. The production of this information would require extensive computer programming to compile historical billing cycle data from the Company's customer information system.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 138

Responding Witness: William Steven Seelye

Q-138. Please explain why Mr. Seelye believes it is appropriate to classify the following KU plant as partially customer-related (as opposed to 100% demand-related):

a. secondary conductors;
b. primary conductors; and,
c. line transformers.

A-138. Primary conductor, secondary conductor, and a line transformer are required to serve a customer regardless of the demand that the customer places on the system.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 139

Responding Witness: Chris Hermann / William Steven Seelye

Q-139. Please provide KU's practices manual (or policies) regarding the size and type of installation for:

a. distribution poles;
b. secondary overhead conductors;
c. primary overhead conductors;
d. secondary underground conductors;
e. primary underground conductors; and,
f. line transformers.

A-139. The selection and installation of poles, conductors and transformers for any given application is based on project specific parameters such as span lengths, terrain, mechanical loading, electrical loading, service quality metrics (voltage, flicker, power factor, etc.), NESC code requirements, Kentucky Administrative Regulations and anticipation of future needs. Common material and equipment selection is optimized through equipment specifications and limited to material approved for use to reduce cost and to ensure consistency, safety and reliability. Information to guide the proper selection, application and installation of poles, conductors and transformers can be found incorporated in various different resources targeted to the separate functional areas of engineering, design and construction including:

- (CS) Construction Standard – Kentucky Utilities and Old Dominion Power
- (JS) LG&E and KU Joint Standards
- (DPG) Electric Distribution System Planning Guidelines, Methodologies and Standards Manual
- Application software and other technical reference material, documents and tools, (such as Alcoa SAG 10, spreadsheets for sizing residential transformers and secondary, etc.) are utilized as needed to properly size poles, conductors and transformers.

a. Attached are documents related to KU's practices manual (or policies) regarding the size and type of installation for distribution poles:

(JS) 04 01 02 - General Requirements for Wood Poles
(JS) 04 01 06 – Typical Pole Weights and Dimensions

b. Attached are documents related to KU's practices manual (or policies) regarding the size and type of installation for secondary overhead conductors:

(CS) A-6-7.0 - Service Conductor Voltage Drop Guide

c. Attached are documents related to KU's practices manual (or policies) regarding the size and type of installation for primary overhead conductors

(CS) A-5-4.0 - Aluminum Conductor Characteristics
(DPG) Sec 3.5 – Overhead Wire Ampacity Ratings

d. Attached are documents related to KU's practices manual (or policies) regarding the size and type of installation for secondary underground conductors:

(CS) A-2-36.0 - Voltage Drop Curves for Single Phase Underground 120/240V System

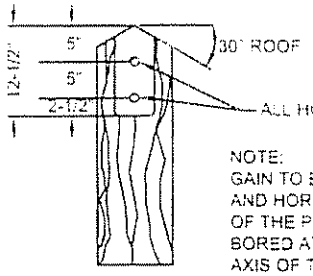
e. Attached are documents related to KU's practices manual (or policies) regarding the size and type of installation for primary underground conductors:

(CS) A-2-25.0 - Standard Underground Conductor Information
(DPG) Sec 3.4 - Underground Cable Ampacity Ratings

f. KU does not have a published document that specifies the size or type of line transformers to be used because optimum size and type is dependent on widely varying factors relating to individual service requirements. Engineers and designers use expected maximum and sustained customer demands, service voltage drops (steady state and instantaneous), anticipated future load growth, and customer voltage requirements to optimize transformer selection.

Attachment to Response to AG-1 Question No. 139(a)
Responding Witness – Chris Hermann/William Steven Seelye

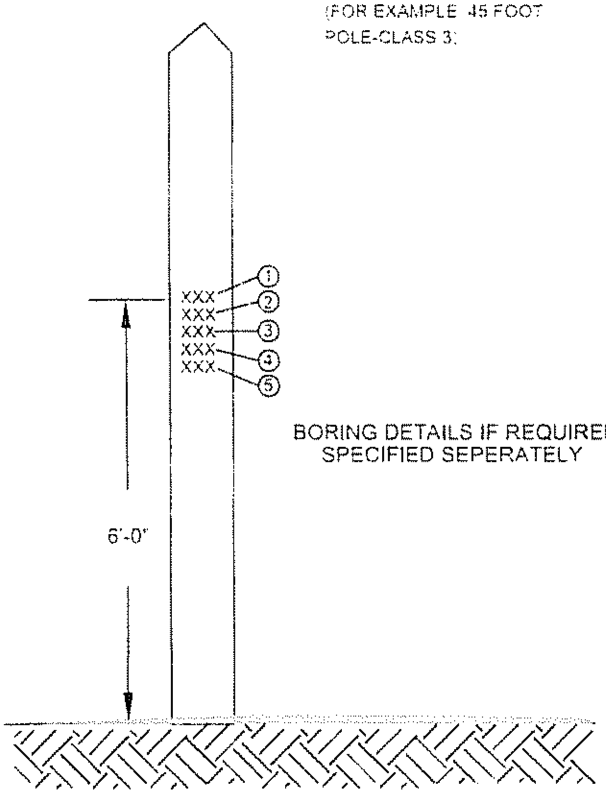
ROOFING AND FLAT GAIN REQUIREMENTS



NOTE:
GAIN TO BE APPROXIMATELY 1/2" DEEP AND HORIZONTAL TO THE VERTICAL AXIS OF THE POLE. THRU BOLT HOLES TO BE BORED AT RIGHT ANGLES TO THE VERTICAL AXIS OF THE POLE AS SPECIFIED ON THE DETAIL DRAWINGS

BRANDING INFORMATION

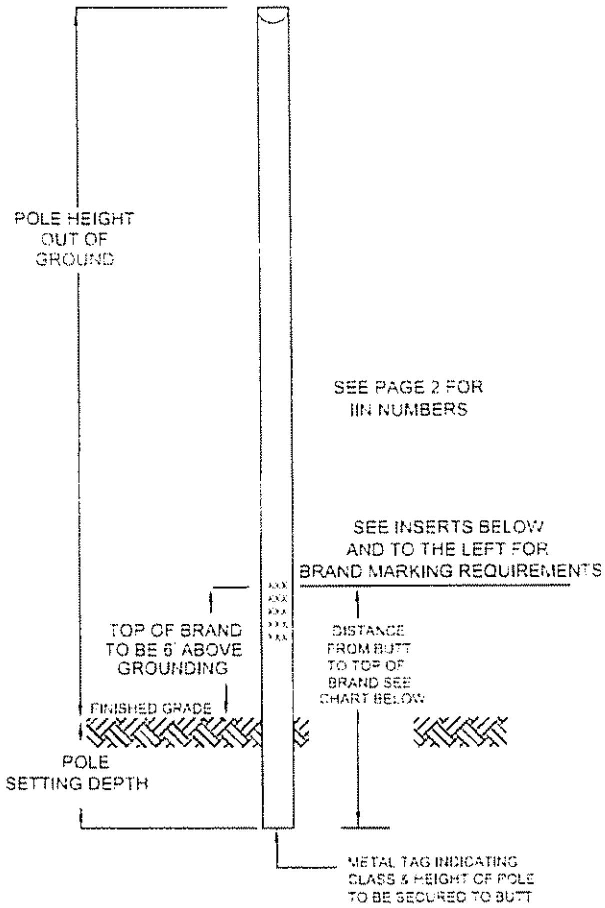
1. LG&E/KU — OWNERS IDENTIFICATION
2. PTC — SUPPLIERS CODE OR TRADE MARK (FOR EXAMPLE-POLE TESTING CO.)
3. F-63 — PLANT LOCATION AND YEAR OF TREATMENT (FOR EXAMPLE FORESTVILLE-1963)
4. SPC — SPECIES AND PRESERVATIVE CODE (FOR EXAMPLE SOUTHERN PINE CREOSOTE)
5. 45-3 — SIZE AND CLASS (FOR EXAMPLE 45 FOOT POLE-CLASS 3)



BORING DETAILS IF REQUIRED SPECIFIED SEPERATELY

BRANDING LOCATIONS

ALL POLES ARE TO BE MARKED WITH BRANDS ON ONE SIDE OF THE POLE PARALLEL TO THE RIDGE OF THE ROOF



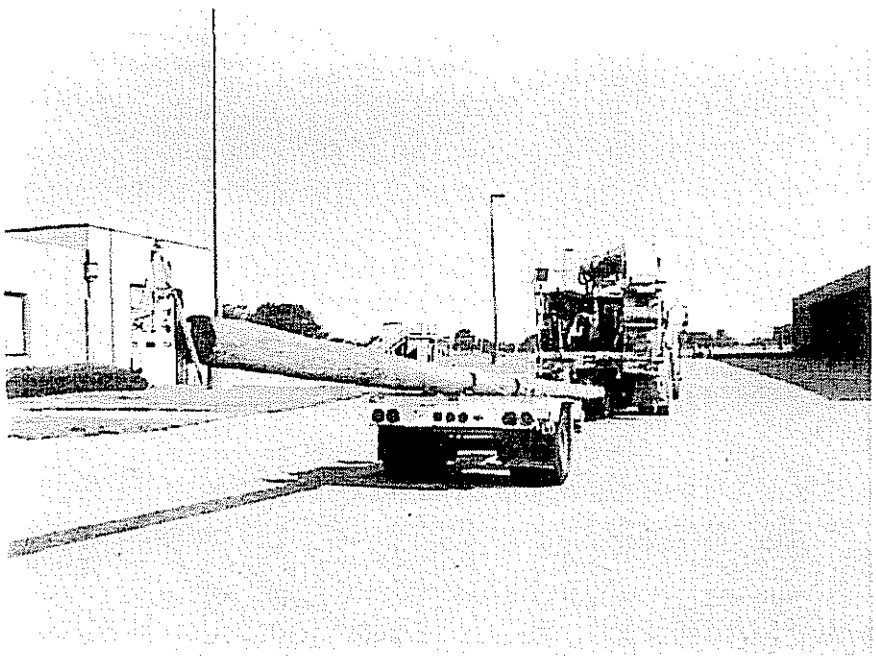
ALL POLES SHALL BE MARKED WITH BRANDS ON SIDE PARALLEL TO THE RIDGE OF THE ROOF

ACTUAL POLE HEIGHT	POLE SETTING DEPTH	POLE HEIGHT OUT OF GROUND	DISTANCE FROM BUTT TO BRAND
25'	5'-0"	20'-0"	11'-0"
30'	5'-6"	24'-6"	11'-6"
35'	6'-0"	29'-0"	12'-0"
40'	6'-0"	34'-0"	12'-0"
45'	6'-6"	38'-6"	12'-6"
50'	7'-0"	43'-0"	13'-0"
55'	7'-6"	47'-6"	13'-0"
60'	8'-0"	52'-0"	14'-0"
65'	8'-6"	56'-6"	14'-6"
70'	9'-0"	61'-0"	15'-0"
75'	9'-6"	65'-6"	15'-6"
80'	10'-0"	70'-0"	16'-0"
85'	10'-6"	74'-6"	16'-6"
90'	11'-0"	79'-0"	17'-0"
95'	11'-6"	83'-6"	17'-6"
100'	12'-0"	88'-0"	18'-0"
105'	12'-6"	92'-6"	18'-6"
110'	13'-0"	97'-0"	19'-0"
115'	13'-6"	101'-6"	19'-6"
120'	14'-0"	106'-0"	20'-0"
125'	14'-6"	110'-6"	20'-6"

POLE CHART

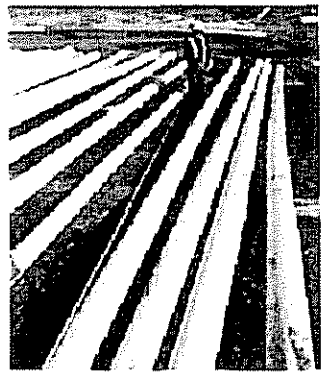
(Pole Height - Class - Type and IIN Number)

	Pole Class											
Height (ft.)	H6	H5	H4	H3	H2	H1	1	2	3	4	5	6
20'												
25'	Southern Pine CCA Treated											0934319
30'									7004950	1196401		7002367
35'	Southern Pine CCA, Penta Or Creosote Treated							7002368		7002369	7002370	
40'							7002371	7002372	7004448	7002373		
45'	Southern Pine CCA. Penta Or Creosote Treated						7002374	7002375	7002376	7002377		
50'	Or						7002378	7002379	7002380			
55'	Douglas Fir Penta or Creosote Treated						7002381	7002382	7002383			
60'							7002384	7002385				
65'	1247501	1247519	1247527	1196860	1196851	1196843	7002386	7005006				
70'	1247694	1247494	1197851	1197860	1196878	1247686	7002388	7002389				
75'	1247719	1247701	1197886	1197127	1197843	1247678	7002390	7002391				
80'	1247735	1247727	1247643	1197119	1197101	7006589	7002392	7006444				
85'	1247751	1247743	1247627	1197094	1197086	7006590	7002393	7004344				
90'	1197060	1247778	1247601	1247619	1197078	7006591	7002394					
95'	1247586	1247794	1247594	1197043	1197051	7006592	7002395					
100'	1247578	1247543	1197019	1197027	1196643	1197035	7001404					
105'	1247560	1247819	1196986	1196994	1196719	7006593	7001405					
110'	1247551	1247827	1196943	1196951	7006594	1196978	7001406					
115'	1196778	1247535	1196894	1247843	1196886	1247835						
120'	1196919	1196786	1196901	1247860	1196960	1247851						
125'	1196935	1196819	1196927	1247886	1197878	1247878						



Pole Height (ft.)	Class	H6	H5	H4	H3	H2	H1	1	2	3	4	5	6
	Top Dia. (")	12.41"	11.78"	11.14"	10.50"	9.87"	9.23"	8.59"	7.96"	7.32"	6.68"	6.05"	5.41"
20'	Bottom Dia. (")							10.41"	9.78"	9.14"	8.50"	7.87"	7.23"
	Dia. Taper ("/ft.)							0.091"/ft	0.091"/ft	0.091"/ft	0.091"/ft	0.091"/ft	0.091"/ft
	Weight (lbs.)							636#	554#	478#	407#	342#	283#
25'	Bottom Dia. (")							11.32"	10.68"	10.04"	9.41"	8.77"	7.92"
	Dia. Taper ("/ft.)							0.109"/ft	0.109"/ft	0.109"/ft	0.109"/ft	0.109"/ft	0.101"/ft
	Weight (lbs.)							876#	768#	667#	574#	487#	395#
30'	Bottom Dia. (")							12.37"	11.54"	10.90"	10.07"	9.43"	8.59"
	Dia. Taper ("/ft.)							0.126"/ft	0.119"/ft	0.119"/ft	0.107"/ft	0.113"/ft	0.106"/ft
	Weight (lbs.)							1171#	1013#	885#	749#	641#	526#
35'	Bottom Dia. (")					14.67"	14.03"	13.20"	12.38"	11.55"	10.72"	9.89"	9.25"
	Dia. Taper ("/ft.)					0.137"/ft	0.137"/ft	0.132"/ft	0.126"/ft	0.121"/ft	0.115"/ft	0.110"/ft	0.110"/ft
	Weight (lbs.)					1874#	1687#	1492#	1291#	1112#	947#	796#	676#
40'	Bottom Dia. (")			17.13"	16.31"	15.48"	14.66"	13.84"	13.01"	12.19"	11.37"	10.54"	9.72"
	Dia. Taper ("/ft.)			0.150"/ft	0.145"/ft	0.140"/ft	0.136"/ft	0.131"/ft	0.126"/ft	0.122"/ft	0.117"/ft	0.112"/ft	0.108"/ft
	Weight (lbs.)			2850#	2565#	2295#	2040#	1800#	1575#	1365#	1170#	990#	826#
45	Bottom Dia. (")	19.58"	18.76"	17.94"	17.12"	16.30"	15.29"	14.47"	13.65"	12.65"	11.83"	11.01"	10.19"
	Dia. Taper ("/ft.)	0.159"/ft	0.155"/ft	0.151"/ft	0.147"/ft	0.143"/ft	0.135"/ft	0.131"/ft	0.127"/ft	0.118"/ft	0.114"/ft	0.110"/ft	0.106"/ft
	Weight (lbs.)	4111#	3748#	3402#	3072#	2759#	2425#	2148#	1888#	1613#	1389#	1182#	991#
50'	Bottom Dia. (")	20.37"	19.55"	18.56"	17.74"	16.92"	15.92"	15.11"	14.11"	13.11"	12.29"	11.47"	
	Dia. Taper ("/ft.)	0.159"/ft	0.156"/ft	0.148"/ft	0.145"/ft	0.141"/ft	0.134"/ft	0.130"/ft	0.123"/ft	0.116"/ft	0.112"/ft	0.109"/ft	
	Weight (lbs.)	4812#	4399#	3953#	3579#	3224#	2844#	2528#	2193#	1882#	1627#	1391#	
55'	Bottom Dia. (")	21.17"	20.17"	19.36"	19.36"	17.37"	16.56"	15.56"	14.57"	13.57"	12.75"		
	Dia. Taper ("/ft.)	0.159"/ft	0.153"/ft	0.149"/ft	0.143"/ft	0.136"/ft	0.133"/ft	0.127"/ft	0.120"/ft	0.114"/ft	0.110"/ft		
	Weight (lbs.)	5570#	5044#	4601#	4125#	3674#	3298#	2896#	2521#	2172#	1885#		
60'	Bottom Dia. (")	21.79"	20.80"	19.81"	18.99"	18.00"	17.01"	16.02"	15.03"	14.04"	13.05"		
	Dia. Taper ("/ft.)	0.156"/ft	0.150"/ft	0.144"/ft	0.141"/ft	0.136"/ft	0.130"/ft	0.124"/ft	0.118"/ft	0.112"/ft	0.106"/ft		
	Weight (lbs.)	6317#	5733#	5178#	4711#	4209#	3735#	3289#	2872#	2484#	2123#		
65'	Bottom Dia. (")	22.41"	21.42"	20.43"	19.45"	18.45"	17.47"	16.48"	15.50"	14.51"	13.52"		
	Dia. Taper ("/ft.)	0.154"/ft	0.148"/ft	0.143"/ft	0.138"/ft	0.132"/ft	0.127"/ft	0.121"/ft	0.116"/ft	0.111"/ft	0.105"/ft		
	Weight (lbs.)	7111#	6469#	5855#	5272#	4720#	4199#	3708#	3248#	2819#	2420#		
70'	Bottom Dia. (")	22.86"	22.05"	21.06"	20.08"	18.92"	17.93"	16.95"	15.97"	14.98"	13.62"		
	Dia. Taper ("/ft.)	0.149"/ft	0.147"/ft	0.142"/ft	0.137"/ft	0.129"/ft	0.124"/ft	0.119"/ft	0.114"/ft	0.109"/ft	0.102"/ft		
	Weight (lbs.)	7871#	7249#	6577#	5937#	5262#	4691#	4154#	3649#	3177#	2689#		
75'	Bottom Dia. (")	23.49"	22.50"	21.52"	20.54"	19.56"	18.40"	17.42"	16.26"	15.28"			
	Dia. Taper ("/ft.)	0.148"/ft	0.143"/ft	0.138"/ft	0.134"/ft	0.129"/ft	0.122"/ft	0.118"/ft	0.111"/ft	0.106"/ft			
	Weight (lbs.)	8757#	7992#	7262#	6567#	5907#	5213#	4627#	4014#	3503#			
80'	Bottom Dia. (")	23.94"	22.95"	21.98"	21.00"	19.85"	18.87"	17.89"	16.73"	15.56"			
	Dia. Taper ("/ft.)	0.144"/ft	0.140"/ft	0.135"/ft	0.131"/ft	0.125"/ft	0.120"/ft	0.116"/ft	0.110"/ft	0.103"/ft			
	Weight (lbs.)	9597#	8770#	7982#	7230#	6436#	5763#	5128#	4463#	3844#			
85'	Bottom Dia. (")	24.57"	23.59"	22.44"	21.46"	20.31"	19.33"	18.18"	17.03"	15.88"			
	Dia. Taper ("/ft.)	0.143"/ft	0.139"/ft	0.133"/ft	0.129"/ft	0.123"/ft	0.119"/ft	0.113"/ft	0.107"/ft	0.101"/ft			
	Weight (lbs.)	10579#	9685#	8736#	7927#	7070#	6344#	5581#	4867#	4201#			
90'	Bottom Dia. (")	25.03"	24.06"	22.91"	21.93"	20.78"	19.63"	18.48"	17.51"	16.19"			
	Dia. Taper ("/ft.)	0.140"/ft	0.136"/ft	0.131"/ft	0.127"/ft	0.121"/ft	0.115"/ft	0.110"/ft	0.106"/ft	0.099"/ft			
	Weight (lbs.)	11502#	10544#	9526#	8657#	7737#	6869#	6053#	5365#	4575#			
95'	Bottom Dia. (")	25.50"	24.52"	23.37"	22.23"	21.25"	20.10"	18.79"	17.81"				
	Dia. Taper ("/ft.)	0.138"/ft	0.134"/ft	0.129"/ft	0.123"/ft	0.120"/ft	0.114"/ft	0.107"/ft	0.104"/ft				
	Weight (lbs.)	12464#	11442#	10353#	9319#	8438#	7507#	6544#	5809#				
100'	Bottom Dia. (")	25.96"	24.98"	23.84"	22.69"	21.55"	20.41"	19.26"	18.12"				
	Dia. Taper ("/ft.)	0.135"/ft	0.132"/ft	0.127"/ft	0.122"/ft	0.117"/ft	0.112"/ft	0.107"/ft	0.102"/ft				
	Weight (lbs.)	13467#	12377#	11217#	10113#	9067#	8078#	7147#	6272#				
105'	Bottom Dia. (")	26.42"	25.28"	24.31"	23.15"	22.02"	20.71"	19.57"	18.42"				
	Dia. Taper ("/ft.)	0.133"/ft	0.129"/ft	0.125"/ft	0.121"/ft	0.116"/ft	0.109"/ft	0.104"/ft	0.100"/ft				
	Weight (lbs.)	14511#	13223#	12119#	10944#	9830#	8670#	7682#	6754#				
110'	Bottom Dia. (")	26.89"	25.75"	24.61"	23.47"	22.32"	21.18"	19.87"	18.73"				
	Dia. Taper ("/ft.)	0.132"/ft	0.127"/ft	0.122"/ft	0.118"/ft	0.113"/ft	0.109"/ft	0.103"/ft	0.098"/ft				
	Weight (lbs.)	15597#	14231#	12928#	11688#	10510#	9395#	8237#	7254#				
115'	Bottom Dia. (")	27.36"	26.22"	25.08"	23.77"	22.63"	21.49"	20.18"	19.04"				
	Dia. Taper ("/ft.)	0.130"/ft	0.125"/ft	0.121"/ft	0.115"/ft	0.111"/ft	0.107"/ft	0.101"/ft	0.096"/ft				
	Weight (lbs.)	16726#	15291#	13901#	12455#	11213#	10036#	8813#	7774#				
120'	Bottom Dia. (")	27.83"	26.52"	25.38"	24.24"	22.94"	21.80"	20.49"	19.35"				
	Dia. Taper ("/ft.)	0.128"/ft	0.123"/ft	0.119"/ft	0.114"/ft	0.109"/ft	0.105"/ft	0.099"/ft	0.095"/ft				
	Weight (lbs.)	17898#	16219#	14768#	13385#	11938#	10699#	9410#	8314#				
125'	Bottom Dia. (")	28.13"	26.99"	25.69"	24.55"	23.24"	22.10"	20.80"	19.49"				
	Dia. Taper ("/ft.)	0.125"/ft	0.122"/ft	0.116"/ft	0.112"/ft	0.107"/ft	0.103"/ft	0.098"/ft	0.092"/ft				
	Weight (lbs.)	18946#	17344#	15660#	14207#	12587#	11384#	10028#	8758#				

Shaded entries are poles with assigned IIN Numbers



Notes:

1. Top and bottom diameters and tapers are based on minimum ANSI dimensions. Most poles will exceed these dimensions by some amount
2. Pole weights are estimated base on poles 15 % larger by volume than ANSI minimum dimensions.
3. Weights are based on a density of 56#/ft 3 for treated poles. Pole weights vary greatly based on actual dimensions, type of treatment, species and moisture content.

Distribution Operations	Title: TYPICAL POLE WEIGHTS AND DIMENSIONS	Standard: 04 01 06	Revision:
LG&E & KU	Description: Typical Table For Pole Heights Class Diameter Taper And Weights	Date: 6/30/03	Drawn By: CLARK/LEAKE
		Scale: None	Sheet: 1 of 1
		Replaces KU Drawing: NA	Replaces LGE Drawing: NA

Attachment to Response to AG-1 Question No. 139(b)
Responding Witness – Chris Hermann/William Steven Seelye

% VOLTAGE DROP PER 100 FEET SPAN LENGTH

SERVICE CONDUCTOR	1Ø LINE CURRENT IN AMPS 50	100	150	200	300	400		3Ø LINE CURRENT IN AMPS 50	100	150	200	300	400	
#4A Triplex	2.0	3.9												
#2A "	1.2	2.5	3.7											
#2/0A "	.6	1.3	1.9	2.6										
#266.8A "	.4	.7	1.1	1.4	2.1									
#397.5A "	.2	.5	.7	1.0	1.5	2.0								
#2A Quadruplex								1.1	2.2	3.2				
#2/0A "								.6	1.1	1.7	2.2			
#266.8A "								.3	.6	.9	1.2	1.8		
#397.5A "								.2	.4	.6	.8	1.3	1.7	
3Wire #8 Copper	2.9	5.8												
" #4 "	1.3	2.5	3.8	5.0				1.1	2.2	3.3	4.4			
" #1 "	.7	1.4	2.2	2.9	4.3			.6	1.3	1.9	2.5	3.7		
" #2/0 "	.6	1.2	1.8	2.4	3.7			.5	.9	1.3	1.8	2.7		
" #4/0 "	.4	.7	1.1	1.5	2.2	2.9		.3	.7	1.0	1.3	2.0	2.7	

Notes:

1. Figures are in % voltage drop on 240 volt base single phase and 240 volt base three phase at 90% P.F.
2. For other span lengths multiply value from above table to convert to actual span length. Example: for 175 foot span multiply % voltage drop from chart by 1.75.

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

REFERENCE INFORMATION	REVISED	SERVICE CONDUCTOR VOLTAGE DROP GUIDE	SCALE
DATE 4-24-59	4-10-73 4-19-74		DRAWING NO. 6-7.0

Attachment to Response to AG-1 Question No. 139(c)
Responding Witness – Chris Hermann/William Steven Seelye

CHARACTERISTICS OF ALUMINUM CONDUCTOR

SIZE	TYPE	STR.	OVERALL DIAMETER IN INCHES	WEIGHT IN POUNDS PER 1000 FT.	BREAKING STRENGTH IN POUNDS	THERMAL(1) CURRENT RATING	RESISTANCE(2) IN OHMS PER 1000 FT.
4	ACSR,Bare	6/1	.250	57.4	1830	148	.444
4	ACSR,Poly	6/1	.313	72.2	1740	120	.444
2*	ACSR,Bare	6/1	.316	91.3	2790	198	.279
2*	ACSR,Poly	6/1	.410	119.0	2650	159	.279
1/0	ACSR,Bare	6/1	.398	145.2	4280	266	.176
1/0	ACSR,Poly	6/1	.523	191.0	4070	210	.176
2/0*	ACSR,Bare	6/1	.447	183.1	5345	307	.138
2/0*	ACSR,Poly	6/1	.572	235.0	5080	242	.138
3/0	ACSR,Bare	6/1	.502	230.9	6675	328	.1102
266.8 MCM	ACSR,Bare	18/1	.609	289.7	6840	465	.0692
266.8 MCM	ACSR,Bare	26/7	.642	367.3	11250	476	.0697
397.5 MCM*	ACSR,Bare	18/1	.743	431.0	10040	598	.0467
397.5 MCM	ACSR,Bare	26/7	.783	547.2	16190	613	.0450
556.5 MCM	ACSR,Bare	26/7	.927	766.1	22400	756	.0335
795 MCM	ACSR,Bare	45/7	1.063	896.0	22900	927	.0231
795 MCM	ACSR,Bare	26/7	1.108	1094.3	31200	949	.0233
795 MCM*	AAC,Bare	37	1.026	746.3	13770	912	.0235

(1) Thermal current ratings are for conductors at a final temperature of 80°C (176°F) with a 45°C rise from 35°C (95°F) ambient, bright sun, and 2 MPH wind. These ratings conform with the established E.C.A.R. Standards. These ratings are the safe loading capacities of the conductors. When designing new lines some capacity should be held in reserve to allow for normal load growth.

(2) Resistances given are for conductors at 38°C (100°F), 13°C (55°F) ambient. 55°F approaches the mean yearly temperature for Kentucky.

*Standard K.U. Distribution Conductor Sizes.

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED		SCALE
DATE 9-19-78		ALUMINUM CONDUCTOR CHARACTERISTICS	DRAWING NO. A-5-4.0

3.5 Overhead Wire Ampacity Ratings

The overhead wire ampacities table is taken from the Engineering Data and Engineering Practices data book maintained by Power Delivery Engineering.

Overhead Wire Ampacities

Conductor Size	Poly W.P. Cu	Bare H.D. Cu	Type "A" C.W.	Poly W.P. Al	Bare H.D. Al	A.C.S.R.	A.C.A.R.	Spacer Cable
6	127	127	140					
4	171	171	180	122				
2	230	230	240	170				156
1/0	309	309		230	230			216
2/0	360	360				270		
3/0	416	416		311		340		282
4/0	485	485						
123 kcmil							280	
195 kcmil							375	
336 kcmil				485	485	570		435
392 kcmil							590	
500 kcmil	788	842						
795 kcmil				840	845	970		747
840 kcmil							965	
1000 kcmil	1206	1300						
1272 kcmil					1130			

The following parameters are used in calculating the thermal limit ampacity rating for each wire:

1) 25 degree C ambient air
2) 50 degree C rise
3) 2 feet per second wind velocity
4) 75 degree C conductor temperature

The formula used to calculate wire ampacity is taken from the "Electrical Transmission and Distribution Reference Book" published by Westinghouse. The formula is as follows:

$$I^2 R = (W_c + W_r) A \quad watts$$

where: I	=	conductor current in amperes
R	=	conductor resistance per foot
W_c	=	watts per square inch dissipated by convection
W_r	=	watts per square inch dissipated by radiation
A	=	conductor surface area in square inches per foot

Watts per square inch dissipated by convection, W_c, is calculated by the following equation:

$$W_c = \frac{0.0128 \sqrt{pv}}{T_a^{0.123} \sqrt{d}} \Delta t$$

where: p	=	pressure in atmospheres (p=1.0)
v	=	velocity of wind in feet per second
T_a	=	average of absolute temperatures of conductor and air in degrees Kelvin
d	=	outside diameter of conductor in inches
Δt	=	temperature rise in degrees C

Watts per square inch dissipated by radiation, W_r, is calculated from the following formula:

$$W_r = 36.8E\left[\left(\frac{T}{1000}\right)^4 - \left(\frac{T_o}{1000}\right)^4\right] \text{ watts per square inch}$$

where E	=	relative emissivity of conductor surface
	=	1.0 for "black body"
	=	0.5 for aluminum and oxidized copper
T	=	absolute temperature of conductor in degrees Kelvin
T_o	=	absolute temperature of surroundings

Using the preceding equations the conductor ampacity "I" can be calculated.

3.6 Voltage Regulation

The following voltage regulations are mandated by the Public Service Commission "Rule V". (***Portions of "Rule V" which do not pertain to voltage have been omitted.***)

3.6.1 Rule V

Part 1

Each utility shall adopt a standard nominal voltage or standard nominal voltages, as may be required by its distribution system for its entire constant-voltage service, or for each of several districts into which the systems may be divided, which standard voltages shall be stated in every schedule of rates of each utility or in its terms and conditions of service.

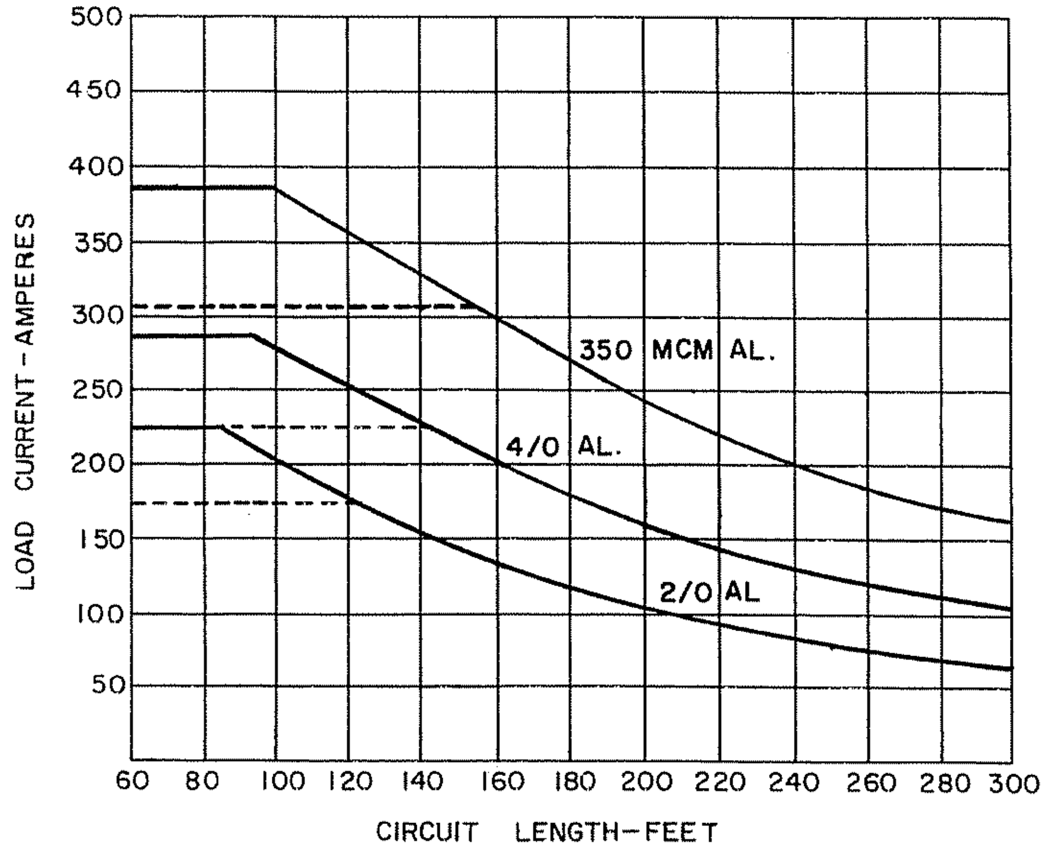
Part 2

Voltage at the customer's service entrance or connection shall be maintained as follows:

a) For service rendered primarily for lighting purposes, the variation in voltage between 5:00 p.m. and 11:00 p.m. shall not be more than five percent (5 percent) plus or minus the nominal voltage adopted, and total variation of voltage from minimum to maximum shall not exceed six percent (6 percent) of the nominal voltage.

Attachment to Response to AG-1 Question No. 139(d)
Responding Witness – Chris Hermann/William Steven Seelye

1. ALUMINUM CONDUCTORS
2. 3% VOLTAGE DROP
3. 90% POWER FACTOR
4. FLAT SOLID LINE INDICATES DIRECT BURIED CABLE THERMAL LIMIT WHILE FLAT DASHED LINE INDICATES CABLE THERMAL LIMIT IN CONDUIT.



CHARTS ADAPTED FROM CYPRUS CABLE UD TECHNICAL MANUAL, 5th EDITION.

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.			
APPROVED [signature] DATE 9-19-78	REVISED	VOLTAGE DROP CURVES FOR SINGLE PHASE UNDERGROUND 120/240V SYSTEM	SCALE DRAWING NO. A-2-36.0

Attachment to Response to AG-1 Question No. 139(e)
Responding Witness – Chris Hermann/William Steven Seelye

Standard Primary Underground Residential Distribution (URD) Cables

PHASE CONDUCTOR			NEUTRAL		THICKNESS (inches)			DIAMETER (inches)			WEIGHT /1000 ft	AMPACITY (AMPS) IN DUCT	
Size (Awg)	Strands	MCP #	#	Size	Strand Shield	Insul	Insul Shield	Bare Phase	Over Insul	Comp Cable	Comp Cable	Single Phase	3 Phase Triplex
2 Al - 1/C	7	1430	10	14	0.015	0.175	0.050	0.292	0.672	0.900	376	148	---
2 Al - 3/C	---	1432	---	---	---	---	---	---	---	---	1128	---	120
2/0 Al - 1/C	19	1431	13	12	0.015	0.175	0.050	0.419	0.799	1.061	614	220	---
2/0 Al - 3/C	---	1433	---	---	---	---	---	---	---	---	1842	---	180

Standard Primary Underground Power Cables

PHASE CONDUCTOR			SHIELD		THICKNESS (inches)				DIAMETER (inches)			WEIGHT /1000 ft	AMPACITY (AMPS) In Duct
Size (Kcm)	Strands	MCP #	#	Size	Strand Shield	Insul	Insul Shield	Jacket	Bare Phase	Over Insul	Comp Cable	Comp Cable	Three Phase
750 Al - 1/C	61	1435	*varies*	*varies*	0.025	0.175	0.060	0.110	0.998	1.398	1.760	1956	---
750 Al - 3/C	---	1438	---	---	---	---	---	---	---	---	---	5868	400
1000 Cu 1/C	61	1436	*varies*	*varies*	0.025	0.175	0.060	0.110	1.152	1.552	1.910	4760	---
1000 Cu 3/C	---	1439	---	---	---	---	---	---	---	---	---	14280	700

Standard Secondary And Service Underground Cables

	PHASE CONDUCTORS			NEUTRAL			DIAMETER (inches)			AMPACITY (AMPS) In Duct	
MCP #	Size (Awg/Kcm)	Stranding	Insul (in)	Size (Awg)	Stranding	Insul (in)	Single Phase Cnd	Comp Cable	Weight /1000 ft	Single Cnd	Triplex
1423	2/0 AL - 1/C	19	0.080	---	---	---	0.566	---	186	170	---
1428	2/0 Al Triplex	19	0.080	1	19	0.080	---	1.223	514	---	180
1424	4/0 Al - 1/C	19	0.080	---	---	---	0.672	---	274	225	---
1429	4/0 Al Triplex	19	0.080	2/0	19	0.080	---	1.452	755	---	240
1425	350 Al - 1/C	37	0.095	---	---	---	0.851	---	437	305	---
3425	350 Al Triplex	37	0.095	4/0	19	0.080	---	1.838	1183	---	320
1426	500 Cu - 1/C	37	0.095	---	---	---	0.978	---	1683	470	---

RP
9-18-96 4:30pm
Files A-2-25PO.DGN
A-2-25PO.DOC

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED
Date 10-17-96

REVISED

STANDARD UNDERGROUND
CONDUCTOR INFORMATION

Scale:

Drawing Number
A-2-25.0

Residential service to multi-family dwellings is either 120/240 volt single-phase or 120/208 volt three-phase four-wire depending upon individual requirements. Normally a distribution transformer is dedicated to serve the building and may be pole mounted or padmounted. A secondary circuit runs from the transformer to a group meter panel that contains a meter for each individual customer.

Service arrangements for commercial and industrial customers vary widely because of the range of load and service requirements The service voltage is either 120/208 volt or 277/480 volt (grounded wye) three-phase four-wire Some commercial and industrial customers, especially older installations, are supplied with 480 volt or 240 volt delta A few commercial and industrial customers are fed by 120/240 volt single-phase service

Some commercial and industrial customers have a primary voltage dual-feed arrangement. Two primary circuits are provided at the transformer location Throw-over switching is used to connect the load to an alternate circuit in the event an outage occurs on the normal feed Switching can be manual or automatic These dual-feed type installations are normally reserved for critical loads such as hospitals

3.4 Underground Cable Ampacity Ratings

The tables in this section contain ampacity ratings for underground cables and overhead wires.

Ampacity tables, shown on pages 5-11 are given for underground cable located in ducts and direct buried The tables are taken from the IEEE-IPCEA Power Cables Ampacities data book. Tables are given for aluminum and copper conductors

<u>Single conductor cables</u>

The following parameters are used in determining ampacities for single conductor cables.

1) Earth Thermal Resistivity (RHO) = 90
2) Conductor Temperature = 90 degree C
3) Ambient Earth Temperature = 20 degree C
4) For residential and commercial applications a load factor (LF) of 50 should be used.
5) For industrial applications a load factor of 75 to 100 should be used

To determine the appropriate table to use for an underground cable ampacity rating the following guidelines are used for various underground cable conditions

III. Distribution Planning Standards

Single-phase and two-phase direct buried circuits

Use single conductor concentric stranded rubber insulated cable buried tables

Three-phase direct buried circuits

Use triplexed concentric stranded rubber insulated cable buried tables

Circuits in ducts encased in concrete

Use triplexed concentric stranded rubber insulated cable in duct tables.

Three Conductor Cables

The following parameters are used in determining ampacities for three conductor cables

1) Earth Thermal Resistivity (RHO) = 90
2) Conductor Temperature = 80 degree C
3) Ambient Earth Temperature = 20 degree C
4) For residential and commercial applications a load factor (LF) of 50 should be used.
5) For industrial applications a load factor of 75 to 100 should be used.

Cable ampacity tables are provided for 8 kV and 15 kV rated copper conductor cables. The 8 kV tables are used for the 4.16 kV distribution system.

Interpolation may be used to approximate ampacities for various numbers of circuits from these tables.

THREE CONDUCTOR SHIELDED SOLID TYPE IMPREGNATED
PAPER INSULATED CABLE IN DUCTS - COPPER CONDUCTOR
RHO 90

1 CABLE IN DUCT BANK 15 kV 80 C CONDUCTOR 20 C AMBIENT EARTH

SIZE	50 LF	75 LF	100 LF
4	116	112	106
2	151	145	138
1/0	199	190	179
2/0	224	214	202
4/0	294	279	262

III. Distribution Planning Standards

250	324	307	288
350	394	372	348
500	481	453	422
750	598	560	519
1000	690	644	594
	3 CABLES IN DUCT BANK 15 kV 80 C CONDUCTOR 20 C AMBIENT EARTH		
4	8	99	90
2	140	127	116
1/0	182	165	149
2/0	205	186	168
4/0	267	240	215
250	294	263	236
350	355	316	282
500	430	381	338
750	529	466	411
1000	606	530	465
	6 CABLES IN DUCT BANK 15 kV 80 C CONDUCTOR 20 C AMBIENT EARTH		
4	98	86	75
2	126	110	96
1/0	163	141	122
2/0	183	158	137
4/0	237	202	175
250	259	221	190
350	311	263	226
500	374	314	269
750	456	380	324
1000	517	429	364
	9 CABLES IN DUCT BANK 15 kV 80 C CONDUCTOR 20 C AMBIENT EARTH		
4	93	80	69
2	119	102	88
1/0	154	130	112
2/0	173	146	125
4/0	222	186	159
250	243	203	173
350	290	241	204
500	347	287	242
750	422	345	290
1000	477	388	325

III. Distribution Planning Standards

TRIPLEXED CONCENTRIC STRANDED RUBBER INSULATED CABLE IN DUCTS COPPER CONDUCTOR CONCENTRIC STRAND RHO-90								
1 CIRCUIT 15 kV - 90 C CONDUCTOR 20 C AMBIENT EARTH								
SIZE		30LF		50LF		75LF		100LF
2		178		173		164		155
1/0		233		225		214		201
2/0		267		257		243		228
4/0		349		336		317		295
250		384		369		347		323
350		465		445		418		387
500		566		540		504		465
750		698		663		616		565
1000		797		755		697		637
3 CIRCUITS 15 kV - 90 C CONDUCTOR 20 C AMBIENT EARTH								
2		170		158		142		128
1/0		222		205		184		165
2/0		253		233		208		186
4/0		330		302		268		238
250		362		330		292		259
350		436		396		349		308
500		528		476		417		366
750		647		579		503		439
1000		735		654		564		490

6 CIRCUITS 15 kV - 90 C CONDUCTOR 20 C AMBIENT EARTH								
2		160		141		121		105
1/0		207		182		155		133
2/0		235		206		175		150
4/0		305		264		223		190
250		334		288		242		207
350		401		344		287		244
500		482		410		340		288
750		585		493		406		343
1000		660		552		452		380

III. Distribution Planning Standards

9 CIRCUIT 15 kV - 90 C CONDUCTOR 20 C AMBIENT EARTH								
2		154		133		112		95
1/0		199		171		142		121
2/0		226		193		160		136
4/0		291		247		204		172
250		319		269		221		187
350		381		319		262		220
500		457		380		309		259
750		553		455		368		307
1000		621		508		408		340

SINGLE CONDUCTOR CONCENTRIC STRANDED RUBBER INSULATED CABLE BURIED

ALUMINUM CONDUCTOR CONCENTRIC STRAND

RHO-90

1 CIRCUIT 3 CABLES 15 kV 90 C CONDUCTOR 20 C AMBIENT EARTH

SIZE		30LF		50LF		75LF		100LF
2		208		196		180		164
1/0		277		259		235		213
4/0		421		389		350		314
350		573		526		468		417
500		714		650		575		508
750		910		822		721		634
1000		1084		972		847		740
1500		1363		1213		1047		910

III. Distribution Planning Standards

2 CIRCUITS 6 CABLES 15 kV 90 C CONDUCTOR 20 C AMBIENT EARTH

2		205		190		171		154
1/0		272		250		223		199
4/0		412		374		330		292
350		559		504		440		386
500		695		621		537		468
750		884		783		672		582
1000		1050		923		786		678
1500		1317		1147		969		830

TRIPLEXED CONCENTRIC STRANDED RUBBER INSULATED CABLE BURIED

ALUMINUM CONDUCTOR CONCENTRIC STRAND

1 CIRCUIT 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

SIZE		30LF		50LF		75LF		100LF
2		157		154		151		147
1		179		176		172		167
1/0		204		201		196		191
4/0		302		297		289		280
350		400		393		383		369
500		487		478		464		447
750		604		591		574		552
1000		698		682		661		635

2 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

2		154		150		143		136
1		176		171		163		154
1/0		201		195		185		175
4/0		296		286		272		256
350		392		378		358		335
500		477		459		432		404
750		590		566		532		496
1000		681		652		611		567

TRIPLEXED CONCENTRIC STRANDED RUBBER INSULATED CABLE IN DUCTS

ALUMINUM CONDUCTOR CONCENTRIC STRAND

RHO-90

1 CIRCUIT 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

SIZE		30LF		50LF		75LF		100LF
1/0		182		176		167		157
4/0		274		263		248		231
350		366		351		329		305
500		449		429		400		370
750		564		536		497		457
1000		656		621		574		525

3 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

1/0		173		160		143		128
4/0		258		236		210		186
350		344		312		275		243
500		419		379		331		291
750		523		468		406		355
1000		605		538		465		404

3 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

1/0		162		142		121		104
4/0		239		207		174		149
350		316		271		226		193
500		383		326		271		229
750		473		399		329		277
1000		544		455		373		314

3 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

1/0		155		133		111		95
4/0		228		193		160		135
350		300		252		206		174
500		363		302		246		206
750		447		368		297		248
1000		512		419		337		280

III. Distribution Planning Standards

SINGLE CONDUCTOR CONCENTRIC STRANDED RUBBER INSULATED CABLE BURIED

COPPER CONDUCTOR CONCENTRIC STRAND

RHO-90

3 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

SIZE		30LF		50LF		75LF		100LF
2		267		251		230		210
2/0		408		381		345		312
4/0		539		499		449		403
350		734		673		600		534
500		911		830		734		649
750		1155		1044		915		805
1000		1365		1225		1066		932
1500		1683		1497		1292		1123
2000		1941		1711		1465		1266

3 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

2		263		244		219		197
2/0		400		367		327		291
4/0		528		480		424		374
350		716		645		563		494
500		887		793		686		598
750		1122		993		853		739
1000		1323		1162		990		854
1500		1626		1415		1196		1025
2000		1870		1612		1351		1152

TRIPLEXED CONCENTRIC STRANDED RUBBER INSULATED CABLE BURIED
COPPER CONDUCTOR CONCENTRIC STRAND

3 CIRCUITS 15 kV-90 C CONDUCTOR 20 C AMBIENT EARTH

SIZE		30LF		50LF		75LF		100LF
2		201		198		194		188
2/0		298		293		286		277
4/0		386		379		370		358
350		509		499		486		469
500		614		602		585		564
750		749		733		711		683
1000		849		830		804		771

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 140

Responding Witness: William Steven Seelye

Q-140. Please explain and define "Power Pool" transformer as referenced in KU Seelye Exhibit 18, page 1.

A-140. Power Pool transformers are capacitors.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 141

Responding Witness: William Steven Seelye

Q-141. Please provide the total installed KU primary voltage Overhead conductors footage.

A-141. See the response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 142

Responding Witness: William Steven Seelye

Q-142. Please provide the total installed KU secondary voltage Overhead conductors footage.

A-142. See the response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 143

Responding Witness: William Steven Seelye

Q-143. With regard to Mr. Seelye's KU direct testimony, page 64, line 13 through page 65, line 8, please provide all academic and theoretical references supporting or discussing "weighted regression analysis" as utilized by Mr. Seelye.

A-143. See response to Question No. 146.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 144

Responding Witness: William Steven Seelye

Q-144. Please explain why Mr. Seelye did not conduct a zero-intercept analysis for KU distribution Poles.

A-144. Unlike conductors or transformers, there is not a functional relationship between the cost or size of a pole and the load (demand) that can be supported by a pole.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 145

Responding Witness: William Steven Seelye

Q-145. With respect to Mr. Seelye's KU zero-intercept analysis (summarized in Exhibits 20 through 22), please provide:

a. statistical output including all diagnostic statistics;
b. specific definition of dependent and independent variable(s) utilized corresponding to the data provided on page 4 of each Exhibit;
c. specific regression model (including coefficient);
d. definition of "size" for each account;
e. definition of "units" for each account; and,
f. source documents supporting Mr. Seelye's regression data.

A-145. a. See response to PSC-2 Question No. 30.
b. For the overhead conductor, the dependent variable is the average cost per foot of conductor and the independent variable is the size of the conductor in MCM. For underground conductor, the dependent variable is the average cost per foot of conductor and the independent variable is the size of the conductor in MCM. For line transformers, the dependent variable is the average cost per transformer and the independent variable is the size of the transformer in KVA.
c. See response to PSC-2 Question No. 30.
d. See response to (b).
e. See response to (b).
f. See response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 146

Responding Witness: William Steven Seelye

Q-146. With regard to Mr. Seelye's "weighted regression" analyses, please explain and provide support for his selected weighted regression based on the square root of "n" (as opposed to some other weighting method). In this response, please provide all engineering and/or statistical support for the square root weighting.

A-146. Multiplying each term of the linear regression model by the square root of "n" is a standard methodology for using least squares to calculate weighted regression coefficients where measurements represent averages and where numbers of units are reported as data, as in the case of the continuing property records utilized by utilities. In statistical software packages, such as SAS, the weight can be specified as "n" rather than the square root of "n". If ordinary least squares regression is used, as in the EXCEL "linest" function, the regression must be performed by multiplying each term by the square root of "n" in order to calculate the proper parameter estimate. The need to multiply each term by the square root of "n" is discussed in most introductory linear regression texts. For example, see pages 103-105 of Samprit Chatterjee and Bertram Price, *Regression Analysis by Example* (John Wiley and Sons, 1977) or pages 179-180 of Douglas C. Montgomery, Elizabeth A. Peck, G. Geoffrey Vinning, *Introduction to Linear Regression Analysis* (Wiley Series in Probability and Statistics, 2006).

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 147

Responding Witness: William Steven Seelye

Q-147. Please provide Seelye KU Exhibits 20 through 22 in executable electronic spreadsheets. In this response include all analyses and calculations conducted to develop each zero-intercept analysis.

A-147. See response to PSC-2 Question No. 30.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 148

Responding Witness: William Steven Seelye

Q-148. Please provide the following by vintage year, size, and type for KU Account 364 (Poles) in the greatest level of detail available:

a. installed units;
b. gross investment;
c. materials investment;
d. capitalized labor; and,
e. Handy-Whitman Cost Index or equivalent.

If all data is not available for all years, please provide the level of detail that is available. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-148. The requested information is not available in a readily accessible form. Developing the requested report would require extensive original analysis.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 149

Responding Witness: William Steven Seelye

Q-149. Please provide the following separated between primary and secondary (as available) by vintage year, size, and type for KU Account 365 (Overhead Conductors) in the greatest level of detail available:

a. installed footage;
b. gross investment;
c. materials investment;
d. capitalized labor; and,
e. Handy-Whitman Cost Index or equivalent.

If all data is not available for all years, please provide the level of detail that is available. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-149. See response to PSC-2 Question No. 30. Gross investment includes both materials investment and capitalized labor. The requested information is being provided on CD. Hard copies are not being provided due to the volume of the data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 150

Responding Witness: William Steven Seelye

Q-150. Please provide the following separated between primary and secondary (as available) by vintage year, size, and type for KU Account 367 (Underground Conductors) in the greatest level of detail available:

a. installed footage;
b. gross investment;
c. materials investment;
d. capitalized labor; and,
e. Handy-Whitman Cost Index or equivalent.

If all data is not available for all years, please provide the level of detail that is available. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-150. See response to PSC-2 Question No. 30. Gross investment includes both materials investment and capitalized labor. The requested information is being provided on CD. Hard copies are not being provided due to the volume of the data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 151

Responding Witness: William Steven Seelye

Q-151. Please provide the following separated between primary and secondary as available by vintage year, size and type for KU Account 368 (Line Transformers) in the greatest level of detail available:

a. installed units;
b. gross investment;
c. materials investment;
d. capitalized labor; and,
e. Handy-Whitman Cost Index or equivalent.

If all data is not available for all years, please provide the level of detail that is available. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-151. See response to PSC-2 Question No. 30. Gross investment includes both materials investment and capitalized labor. The requested information is being provided on CD. Hard copies are not being provided due to the volume of the data requested.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 152

Responding Witness: William Steven Seelye

Q-152. Please explain how and where Curtailable Rider revenue credits are reflected in the KU revenue proof (Seelye Exhibit 5) and class cost of service study (Seelye Exhibits 18 and 19).

A-152. Curtailable Rider revenue credits are included in the row labeled "Sales" on pages 34 through 36 of Seelye Exhibit 19. Curtailable Rider revenue credits are shown as CSR amounts for the applicable large industrial rate schedules shown on Seelye Exhibit 5.

KENTUCKY UTILITIES COMPANY

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

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 153

Responding Witness: William Steven Seelye

Q-153. Regarding Mr. Seelye's KU direct testimony, page 56, footnote 5, please provide:

a. a copy of the referenced Order;
b. a copy of Mr. Seelye's direct testimony and exhibits in the referenced case; and,
c. a copy of any rebuttal and surrebuttal testimony filed on behalf of the Applicant (by any witness) in the referenced case.

A-153. a. See attached.

b. Mr. Seelye did not submit testimony in Case No. 90-158.

c. See attached.

LG&E Case No. 90-158 Final Order
Responding Witness – William Steven Seelye

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY 40602
(502) 564-3940

CERTIFICATE OF SERVICE

Re: Case No. 90-158
Louisville Gas and Electric Company

I, Lee M. MacCracken, Executive Director of the Public Service Commission, do hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U. S. Mail on the 21st day of December, 1990.

Parties of Record:

Mr. David Carey
Hon. Christine Hansen
Hon. Katherine Randall
Hon. Paul E. Reilender, Jr.
Hon. Don Meade
Hon. J. Bruce Miller
Hon. David A. McCormick
Hon. Candy A. Culin
Hon. Anthony G. Martin
Hon. Bruce Abel
Hon. Mark W. Dobbins
Hon. Fred Bradley
Hon. Gardner F. Gillespie
Mr. William A. Noyes
Hon. James E. Isenberg

Lee M MacCracken

Executive Director

LMM/cbg

Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 90-158

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY) CASE NO. 90-158

O R D E R

On June 29, 1990, Louisville Gas and Electric Company ("LG&E") filed an application with the Commission requesting authority to increase its electric and gas rates for service rendered on and after August 1, 1990. The proposed rates would increase annual electric revenues by $31,015,938, an increase of 6.22 percent, and annual gas revenues by $3,837,454, an increase of 2.24 percent. These increases represent an annual increase in total operating revenues of $34,853,392, or 5.43 percent, based on normalized test-year sales. This Order grants an increase in annual electric revenues of $5,451,758, an increase of 1.17 percent, and an increase in annual gas revenues of $524,487, an increase of .30 percent. These increases represent an annual increase in total operating revenues of $5,976,245, or .93 percent, based on normalized test-year sales.

The Commission granted motions to intervene filed by the Attorney General, by and through his Utility and Rate Intervention Division ("AG"); Jefferson County ("Jefferson"); the city of Louisville ("Louisville"); the Department of Defense of the United States ("DOD"); the Kentucky Industrial Utility Customers

("KIUC"); the Paddlewheel Alliance ("Paddlewheel"); the Kentucky Cable Television Association, Inc. ("KCTA"); the Metro Human Needs Alliance, Inc., which assists low-income households ("MHNA"); the International Brotherhood of Electrical Workers, Local 2100; and Reynolds Metals Company. The Commission suspended the proposed rate increase through December 31, 1990 in order to conduct an investigation into the reasonableness of the proposed rates. A public hearing was held in the Commission's offices in Frankfort, Kentucky, on November 7-9, 19-21, and 26, 1990 with all parties of record represented. Simultaneous briefs were filed on December 14, 1990. All information requested during the hearing has been submitted.

COMMENTARY

LG&E is a privately owned electric and gas utility which generates, transmits, distributes, and sells electricity to approximately 321,300 consumers in Jefferson County and in portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble counties. LG&E distributes and sells natural gas to approximately 243,400 consumers in Jefferson County and in portions of Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington counties.

TEST PERIOD

LG&E proposed the 12-month period ending April 30, 1990 as the test period for determining the reasonableness of the proposed rates. LG&E also proposed to reflect the impact of the commercialization of the Trimble County Unit No. 1 ("Trimble

County") Generating Plant which was scheduled for late December 1990. Jefferson, Louisville, and Paddlewheel ("Jefferson et al.") and KIUC opposed this approach, stating that LG&E had created a hybrid test year which was neither fully historic nor fully projected. The Commission believes it is reasonable to utilize the 12-month period ending April 30, 1990 as the test period in this proceeding. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

NET ORIGINAL COST RATE BASE

Trimble County

LG&E proposed a total company net original cost rate base of $1,444,036,873. Trimble County was reflected in rate base by including test year end Construction Work in Progress ("CWIP") of $677,170,687, plus estimated additional expenditures through December 31, 1990 of $37,829,317, less $178,750,000 to reflect the 25 percent disallowance for Trimble County ordered by the Commission in Case No. 9934.[1] LG&E also included in its proposed accumulated depreciation the first year depreciation expense on the December 31, 1990 estimated level of investment in Trimble County, exclusive of the 25 percent disallowance. LG&E cited two reasons for including Trimble County in the net original cost rate base. First, it stated that the Trimble County expenditures are known and measurable; and second, it claimed that the Settlement Agreement, Article IX, approved in Case No. 10320,[2] provide an

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[1] Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1, Order dated July 1, 1988.

absolute right to recover 75 percent of its Trimble County investment, including depreciation.

While the AG, Jefferson et al., and KIUC all filed testimony opposing LG&E's proposed treatment of Trimble County, none of these intervenors prepared a net original cost rate base. Their testimony focused on the impact that LG&E's proposals had on total capitalization, discussed later in this Order.

The Commission finds that the post test-year Trimble County expenditures are not known and measurable but, rather, are a moving target. On numerous occasions during the course of this case, LG&E revised its estimated December 31, 1990 level for Trimble County CWIP. In fact, LG&E's most recent revision discloses that almost $11,000,000 of Trimble County CWIP will not be spent until after January 1, 1991.

In proposing this rate base treatment for Trimble County, LG&E has ignored a basic concept of rate-making, the matching principle. While all rate base items except Trimble County are established at actual April 30, 1990 levels, LG&E has included a post test-year plant addition for Trimble County CWIP and the related accumulated depreciation at the estimated December 31, 1990 level. The Commission has a well-established, rate-making policy on the inclusion of post test-period plant additions. All utilities under the Commission's jurisdiction were given notice that, if a historic test period is used, adjustments for post

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2 Case No. 10320, An Investigation of Electric Rates of Louisville Gas and Electric Company to Implement a 25 Percent Disallowance of Trimble County Unit No. 1, Order dated October 2, 1989.

test-period plant additions should not be requested unless all revenues, expenses, rate base, and capital items have been updated to the same period as the plant additions.[3] LG&E acknowledged that it was aware of this policy but argued that it should not apply to this case because the policy was announced after the Settlement Agreement was signed on August 11, 1989.

The Commission is not persuaded by LG&E's argument. The date that the Settlement Agreement was signed has no particular significance in determining the applicability of the rate-making policy announced on August 22, 1989 in Case Nos. 10201[4] and 10481. The Settlement Agreement did not become binding and enforceable until approved by the Commission on October 2, 1989, six weeks after the Commission declared that:

> Therefore, in cases filed after this decision is issued, the Commission gives notice to Columbia [Kentucky-American] and other utilities under its jurisdiction that: 1) adjustments for post test-period additions to plant in service should not be requested unless all revenues, expenses, rate base, and capital items have been updated to the same period as the plant additions. . . .[5]

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3 Case No. 10481, Notice of Adjustment of the Rates of Kentucky-American Water Company Effective on February 2, 1989, Order dated August 22, 1989, page 5.

4 Case No. 10201, Adjustment of Rates of Columbia Gas of Kentucky, Inc., Order dated August 22, 1989.

5 Case No. 10201, Order dated August 22, 1989, page 6; and Case No. 10481, Order dated August 22, 1989, page 5.

This rate-making policy, having been announced before the Settlement Agreement was approved, and long before this rate case was filed, is applicable and controlling. Further, there is no language in the October 2, 1989 Order approving the Settlement Agreement that allows LG&E to disregard this policy.

Nevertheless, this Commission also recognizes that Trimble County represents a significant addition to LG&E's utility plant in service. By the date the rates authorized in this Order take effect, Trimble County will be in commercial operation and all Trimble County expenditures will be reclassified from CWIP to plant-in-service. Therefore, the Commission must consider the commercialization of a major plant addition and at the same time adhere to rate-making concepts, time tested for fairness and reasonableness.

We believe it fair and reasonable in this instance to include in LG&E's net original cost rate base the test-year-end Trimble County CWIP. This amount, net of the 25 percent disallowance, is $507,878,016. This rate-making treatment is essentially the same that LG&E has received throughout the construction of Trimble County. The Commission also finds it reasonable in this instance to allow depreciation expense on 75 percent of the Trimble County CWIP balance as of the end of the test year. The first year depreciation expense has been included in the accumulated depreciation used in determining the net original cost rate base. This approach properly recognizes the known and measurable fixed cost associated with the commercialization of Trimble County. The Commission cannot and will not include in rate base the post test-period plant additions for Trimble County or the related first year depreciation expense. To do otherwise would disregard established, and we feel fair, just and reasonable rate-making practices enunciated and adopted in prior Commission decisions concerning post test-period plant additions.

Fuel Inventory

LG&E proposed to include $14,297,235 as fuel inventory in its rate base calculations. This amount represents the test-year end balance for the fuel inventory account. During the hearing, LG&E indicated that it began to purchase coal for Trimble County in January 1990, but had not adjusted the fuel inventory to reflect a 25 percent disallowance of the Trimble County coal. The AG proposed to remove 25 percent of the increase in the fuel inventory between April 30, 1989 and April 30, 1990, stating the entire increase had to be related to Trimble County.

Based on a monthly account balance for fuel inventory review, the Commission believes it is more appropriate to use a 13-month average balance for fuel inventory in the calculation of rate base. The use of a 13-month average balance is consistent with our usual practice. The Commission also believes it is reasonable to remove from the fuel inventory 25 percent of the coal inventory related to Trimble County coal. The 13-month average balance for fuel inventory, including the Trimble County coal was $10,280,683.[6] The Commission has calculated a 13-month average balance, removing the Trimble County coal from each monthly

6 Response to Commission's Order dated June 29, 1990, Item 9.

balance, and finds that $10,270,961 should be used in the calculation of rate base.

<u>Materials, Supplies, and Prepayments</u>

In determining its net original cost rate base, LG&E used the test-year end balances for materials, supplies, and prepayments. The AG proposed to remove 25 percent of the increase in materials and supplies between April 30, 1989 and April 30, 1990, stating the entire increase had to be related to Trimble County. The Commission has reviewed the monthly account balances for these accounts, and as discussed previously, believes it is more appropriate to use a 13-month average balance for these accounts in the calculation of rate base. The Commission also believes it is reasonable to remove from materials and supplies 25 percent of any amounts related to Trimble County. During the hearing, LG&E indicated that $1,945,000[7] was included in materials and supplies for Trimble County. The 13-month average balance for materials and supplies, including the Trimble County materials and supplies, was $32,691,260.[8] The Commission would prefer to adjust the Trimble County amounts out on a monthly basis, and then compute the 13-month average. In this instance, the detailed information

7 Transcript of Evidence ("T.E."), Volume IV, November 19, 1990, pages 181 and 182.

8 Response to Commission's Order dated June 25, 1990, Item 9.

is not available. Therefore, the Commission has deducted $486,250[9] from the $32,691,260 average, and included $32,205,010 in rate base for materials and supplies. We included $748,304[10] for prepayments in our calculation of rate base.

Stores Expense

The AG also proposed to remove 25 percent of the increase in stores expense between April 30, 1989 and April 30, 1990, for the same reason stated in his adjustment to materials and supplies. At the hearing, LG&E stated that $434,000 in stores expense was related to Trimble County.[11] The Commission believes it is appropriate to remove 25 percent of its Trimble County stores expense from the rate base calculations. The test-year-end balance of $5,790,584 has been reduced by $108,500[12] to reflect the removal of the 25 percent Trimble County stores expense.

Gas Stored Underground

LG&E proposed to include $20,450,243 as gas stored underground in its calculation of rate base. This amount represented a 12-month average balance of the gas stored underground account. Again we believe it is more reasonable to use the 13-month average balance, and have included $19,515,080 as gas stored underground in the calculation of rate base.

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9 $1,945,000 x 25 percent = $486,250.

10 Response to Commission's Order dated June 29, 1990, Item 9.

11 T.E., Volume IV, November 19, 1990, pages 181 and 182.

12 $434,000 x 25 percent = $108,500.

Cash Working Capital Allowance

LG&E determined its cash working capital allowance using the 45 day or 1/8 formula methodology. This Commission has traditionally used this approach in rate cases and do again here. We have adjusted the allowance for cash working capital to reflect the accepted pro forma adjustments to operation and maintenance expenses.

In determining the cash working capital allowance, LG&E deducted from the operation and maintenance expenses the gas supply expenses. The level of gas supply expenses removed did not equal the amount LG&E deducted in its operating expense adjustment for gas supply expenses. It is best to use the same amount in both adjustments. Therefore, we have used the operating expense adjustment level of gas supply expenses in the calculation of the cash working capital allowance.

Based upon the previous findings, we have determined the net original cost rate base for LG&E at April 30, 1990 to be as follows:

	Electric	Gas	Total
Total Utility Plant	$1,915,177,722	$221,751,683	$2,136,929,405
Add:			
Materials & Supplies	46,804,173	1,353,882	48,158,055
Gas Stored Underground	0	19,515,080	19,515,080
Prepayments	621,092	127,212	748,304
Cash Working Capital	32,815,128	4,441,938	37,257,066
Subtotal	$ 80,240,393	$ 25,438,112	$ 105,678,505
Deduct:			
Reserve for Depreciation	529,783,546	84,484,852	614,268,398
Customer Advances	1,572,719	5,134,306	6,707,025
Accumulated Deferred Taxes	193,385,140	19,093,760	212,478,900
Investment Tax Credit (Prior Law)	1,127,320	427,400	1,554,720
Subtotal	$ 725,868,725	$109,140,318	$ 835,009,043
NET ORIGINAL COST RATE BASE	$1,269,549,390	$138,049,477	$1,407,598,867

Reproduction Cost Rate Base

LG&E presented a reproduction cost rate base of $2,605,266,805,[13] which included electric facilities of $2,238,145,899 and gas facilities of $367,120,906. LG&E estimated the value of plant in service, plant held for future use, and CWIP at the end of the test year. LG&E also reflected the same adjustments it had included in its net original cost rate base. We have given consideration to the proposed reproduction cost rate base.

CAPITAL

LG&E proposed a total capitalization of $1,384,481,820.[14] Included in the total capitalization were five adjustments, which

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13 Fowler Direct Testimony, Exhibit 5.

14 Fowler Direct Testimony, Exhibit 2, page 1 of 2.

LG&E allocated on a pro rata basis to all components of capital. The five adjustments were for the Job Development Investment Tax Credit ("JDIC"), the 25 percent disallowance of test year Trimble County CWIP, the unamortized balance of extraordinary retirements as determined by the Commission in Case No. 10064,[15] the estimated additional expenditures for Trimble County through December 31, 1990 net of the 25 percent disallowance, and the capital costs relating to LG&E's new office building.

The AG proposed a total capitalization of $1,352,739,019.[16] The AG added to total debt capital the difference between the 12-month average balance of gas stored underground and the April 30, 1990 balance. The AG deducted from common equity the entire 25 percent disallowance of test-year Trimble County CWIP and 25 percent of the net increase in fuel and supplies increases. After making these adjustments, the AG allocated on an adjusted pro rata basis the JDIC, the unamortized balance of extraordinary retirements, and the capital costs relating to LG&E's new office building. The AG stated that the adjustment to debt capital was necessary because the test-year end balance was not representative of the 12-month average balance, and it was logical to assume that the gas balances were financed by short-term debt since they varied greatly during the test year. The AG's proposal to remove

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15 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, Order dated July 1, 1988.

16 DeWard Direct Testimony, Exhibit TCD-1, Schedule 3.

the 25 percent Trimble County CWIP disallowance totally from common equity was based on the Settlement Agreement approved in Case No. 10320, which assigned any benefits, profits, or entitlements realized on the disallowed 25 percent of Trimble County to the shareholders of LG&E. The AG stated that LG&E had put itself at risk for both the costs and rewards related to the 25 percent disallowance. MHNA supported the AG's position on this issue.[17] The AG stated that it was logical that LG&E would begin to increase levels of fuel and supplies for Trimble County and that 25 percent of those increases should also be removed.

KIUC proposed a total capitalization of $1,356,100,000.[18] KIUC began with LG&E's total proposed capitalization and removed the pro rata allocation of the estimated additional expenditures for Trimble County through December 31, 1990. KIUC stated that LG&E had created a hybrid historic and forecasted test year, inconsistently relying upon actual historic costs in some instances and totally forecasted costs in other instances.[19]

Jefferson et al. did not propose an amount for total capitalization, but took issue with LG&E's proposal to include the estimated additional expenditures for Trimble County through December 31, 1990. Jefferson et al. stated that LG&E's application had to be evaluated using the historic test year

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17 Brief of MHNA, pages 7 and 8.

18 Kollen Direct Testimony, Table 6, page 42.

19 Id., page 13.

approach, and these additional expenditures did not constitute known and measurable items.

The Commission does not agree that an adjustment to the capitalization is necessitated by the use of an average balance for gas stored underground in the rate base determination. Nor do we agree with the argument that LG&E finances its gas stored underground exclusively through debt capital. In determining the capitalization of a utility, the Commission establishes the overall embedded capital needs which includes working capital items which vary in value throughout the course of a 12-month test period. These variations are sufficient to compensate LG&E for the monthly variations in gas stored underground. Such an adjustment is not necessary in this case.

Concerning the AG's proposal to remove the entire 25 percent disallowance of Trimble County CWIP from common equity, the Commission has ruled in prior cases that the investment in utility plant cannot be traced to specific capital sources. The AG presented no evidence to demonstrate that this investment actually came from common equity alone. Trimble County's construction has been financed by all components of capital, not solely by common equity. It is reasonable to allocate the disallowance on a pro rata basis, in order to reflect this fact. The Commission notes the inconsistency of the AG's position on this adjustment. While proposing a higher level of debt for capitalization, this higher level of debt was not reflected in the AG's proposed rate of return.

The Commission has determined that LG&E's total test-year end capitalization should be $1,355,523,360. The Commission has accepted all of LG&E's proposed adjustments to capitalization with the exception of the estimated additional expenditures on Trimble County through December 31, 1990. As has been discussed earlier in this Order, the Commission has determined that it is not reasonable nor equitable to include these estimated expenditures in rate base without concurrent adjustments to revenues and expenses. Likewise, capitalization must reflect only the level of Trimble County expenditures as of test-year end. The Commission has also adjusted the capitalization for the amount removed from rate base relating to the Trimble County coal inventory, materials and supplies, and stores expense.

PROPOSED PHASE II PROCEEDING

LG&E proposed a "Phase II" proceeding in addition to the current rate case. As proposed, Phase II would establish a process whereby LG&E could recover the allowable 75 percent portion of operation and maintenance expenses associated with the operation of Trimble County. Four areas would be addressed in Phase II. LG&E proposed to file with the Commission calculations annualizing the first three months of actual operating and maintenance expenses at Trimble County, as adjusted for unrepresentative costs. Operating expenses would be reduced by any Trimble County labor expenses recovered in this proceeding. Operating and maintenance expenses would also be reduced by 25 percent of the administrative and general expenses associated with the operation of Trimble County. Additional adjustments would be made to reduce the operating and maintenance expenses by the net revenues realized from off-system sales attributable to the allowable 75 percent portion of Trimble County and depreciation on Cane Run Unit No. 3, if the unit has been retired.[20] LG&E offered this process as a means to avoid the expenses and time associated with additional rate case proceedings, reduce the effects of regulatory lag, avoid the problems associated with a forecasted test year proceeding, and benefit LG&E's customers by allowing it to avoid future rate filings for a period of time.[21]

The AG, KIUC, and Jefferson et al. are opposed to the Phase II proposal. The AG questioned LG&E's willingness to provide information necessary to evaluate such a filing and how representative three months of operational data and off-system sales would be on a going forward basis.[22] KIUC characterized it as an attempt to inappropriately accelerate its Trimble County cost recovery and that the plan was premature and poorly designed.[23] Jefferson et al. cited problems with the three months chosen for annualization, the complexity of calculating the annualization, and how known and measurable the final results would be.[24]DOD stated that the proposal was too narrow in scope.[25]

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20 Fowler Direct Testimony, page 31.

21 Id., page 3.

22 DeWard Direct Testimony, pages 53 and 54.

23 Kollen Direct Testimony, pages 5 and 22.

24 Kinloch Direct Testimony, pages 15 and 16.

25 Brief of DOD, page 11.

The Commission does not believe it is reasonable to accept the Phase II proposal. The abbreviated proceeding would make it difficult to properly match revenues, expenses, rate base, and capital items. Significant non-Trimble County events would be excluded from Phase II. There is insufficient evidence to demonstrate that an annualization of three months of actual Trimble County data would be representative of going forward conditions.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $121,674,031.[26] LG&E originally proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted net operating income of $122,043,734.[27] Subsequently, LG&E proposed several correcting adjustments. The proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Revenue Normalization - Electric

LG&E proposed normalized electric operating revenues of $502,388,879 based on the rates in effect at the end of the test year. In normalizing its electric revenues, LG&E made adjustments to reflect year-end customers, to eliminate a non-recurring refund, and to eliminate the effect of changing to the unbilled method of recording revenues midway through the test year.

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26 Fowler Direct Testimony, Exhibit 1, page 1 of 3.

27 Id., page 3 of 3.

KIUC proposed an adjustment to increase normalized electric revenues by $4,896,459 to recognize for rate-making purposes the initial booking of unbilled revenues reported by LG&E in January 1990. The adjustment proposed by KIUC reflects a 3-year amortization of LG&E's initial booked amount of $14,689,378. KIUC contends that a one-time event such as LG&E's initial booking of unbilled revenues should be given rate-making treatment consistent with that afforded the one-time downsizing for which LG&E proposed a 3-year amortization. KIUC maintains that both the downsizing costs and the initial booking of unbilled revenues should either be amortized and included in the determination of LG&E's revenue requirements or treated as one-time, non-recurring events that were booked during the test year, will not impact future earnings, and should be excluded from the determination of LG&E's revenue requirements.

LG&E's proposed adjustments are reasonable for determining normalized electric revenues. No adjustment should be made to amortize the amounts included in LG&E's initial booking of unbilled revenues. The initial booking is a one-time occurrence recorded during the test year that will not impact future periods during which the approved rates will be in effect.

<u>Revenue Normalization - Gas</u>

LG&E proposed normalized gas operating revenues of $194,585,467 based on the rates in effect at the time of filing its application. In normalizing its gas revenues, LG&E made adjustments to reflect normal weather conditions and year-end customers. LG&E eliminated the effect of changing to the unbilled method of recording revenues and adjusted its gas cost revenues to $130,285,428 based on its wholesale gas cost in effect at the time the application was filed.

KIUC proposed an adjustment to increase LG&E's normalized gas revenues by $5,034,036 to reflect a 3-year amortization of LG&E's initial booking of unbilled revenues. This was the same adjustment KIUC proposed for LG&E's electric revenues. For the same reasons previously cited in the discussion of electric revenues, the Commission finds that no adjustment should be made.

LG&E's normalized gas operating revenues have been reduced by $11,289,435 to $183,296,032 based on LG&E's latest gas cost adjustment effective November 1, 1990.[28] This includes gas cost revenues of $118,995,993 based on LG&E's current cost of gas. LG&E's purchased gas expense has also been reduced to this amount to reflect the current gas cost adjustment. With this adjustment, LG&E's gas operating revenues will be properly normalized for rate-making purposes.

Fuel Cost Recovery

On an adjusted basis, LG&E's electric fuel cost exceeded its fuel cost recovery by $1,737,240 during the test year. The AG proposed an adjustment to reduce fuel expense by $1,737,240 in order to match fuel cost and fuel cost recovery to ensure that the test-year under-recovery of fuel costs did not impact the setting of base rates in a non-fuel cost rate proceeding.

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28 Case No. 10064-J, The Notice of Purchased Gas Adjustment Filing of Louisville Gas and Electric Company, Order dated November 1, 1990.

LG&E maintains that the AG's adjustment was based on an erroneous understanding of the fuel adjustment clause ("FAC"). LG&E contends that the timing difference that exists between the incurrence of fuel costs and the recovery of fuel costs prohibits a matching of fuel cost and fuel revenues in any 12-month period. LG&E recounts that these types of adjustments have not been made in its past rate cases because the FAC was not designed to match revenues with expenses but was designed to track a variable cost outside of a general rate proceeding.

LG&E opines that the over- and under-recovery mechanism approved in Administrative Case No. 309[29] will improve the match between fuel cost and fuel revenues but will not provide for a full reconciliation of costs and that the proposed adjustment would deprive LG&E of the opportunity to fully recover its costs.

It is true that the current FAC does not produce an absolute synchronization of fuel costs and fuel cost recovery. Nor does it result in a full reconciliation of costs that will produce a precise matching of fuel costs and fuel revenues in any 12-month reporting period. The current FAC, however, with the over- and under-recovery mechanism approved in Administrative Case No. 309 is fully recovering, meaning that all allowable fuel costs will, over time, be recovered through the clause.

In the past, the FAC tracked fuel costs for one month in order to determine an adjustment factor that would be applied to a

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29 Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Order dated December 18, 1989 and Order dated April 16, 1990.

subsequent month's kilowatt-hour sales. This factor, applied with a 2-month lag to a different level of sales, would produce an over- or under-recovery for the billing month that was not tracked, or reconciled, in subsequent months. Once incurred, a monthly over- or under-recovery was lost, either to the utility or the ratepayer, and was not subject to true-up at a later date.

The over- and under-recovery mechanism now in place ensures that a given month's over- or under-recovery will be tracked and included in the utility's fuel cost calculation in a later month. The result is a fully recovering FAC through which all allowable fuel costs will, over time, be recovered. With recovery of fuel costs through the FAC assured, it is improper to include the over- or under-recovery of a given test year in the determination of a utility's revenue requirements. Therefore, an adjustment should be made to eliminate LG&E's test-year under-recovery of $1,737,240.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $3,570,447 for labor and labor-related costs. The actual cost items and the proposed adjustments to combined gas and electric operations are as follows:

	Total
Wages and Salaries	$4,010,669
FICA Taxes	334,829
Federal Unemployment	21,262
State Unemployment	41,348
Health Insurance	(636,899)
Pensions	(462,358)
Dental Insurance	29,463
Group Life Insurance	232,133
	$3,570,447

Wages and Salaries. LG&E proposed to increase wages and salaries by $4,010,669. The proposed increase reflected the effects of base wage increases granted to non-union employees during the test year, a lump sum transition payment to non-union employees during the test year, a 3 percent wage increase for union employees effective November 12, 1990, and a change in the labor capitalization rate due to the future commercialization of Trimble County. LG&E's adjustment included the annualization of the actual test-year-end levels of wages for each employee group. The November wage increase was applicable to all of LG&E's union employees, including those identified as "project temporaries" who work at Trimble County. Instead of using its test-year actual labor capitalization rate, LG&E used the capitalization rate for the month of April 1990 and adjusted it to reflect the changes expected in labor operating expenses due to the commercialization of Trimble County. This adjusted labor capitalization rate was included in all of LG&E's labor and labor-related cost adjustments.

The AG disagreed with three components of LG&E's proposed adjustment: (1) allowing the 3 percent union wage increase for the project temporaries, citing LG&E's statements that these employees would no longer be employed once Trimble County was in commercial operation; (2) the inclusion of the lump sum transition payment to non-union employees, stating that future incentive payments were not known and measurable and not appropriate for inclusion; and (3) the use of the adjusted April 1990 capitalization rate, inasmuch as LG&E had not established that

April was a representative month and that LG&E was attempting to recover Trimble County costs without making necessary adjustments to off-system sales and expenses.

KIUC recommended that all non-Trimble County pre- and post-test-year adjustments proposed by LG&E be rejected as inconsistent with the basic underlying concepts of determining the test year basis for fair, just, and reasonable rates.[30] KIUC included the November 1990 union wage increase in this group of adjustments. KIUC further argued that all pro forma adjustments proposed by LG&E be rejected in the absence of a complete set of appropriate pro forma adjustments to non-Trimble County operating income and rate base.[31]

LG&E's proposed adjustment to wages and salaries is reasonable, except for two issues. While the November union wage increase is based on the union contract, the Commission does not believe it is appropriate to allow the 3 percent increase for the Trimble County project temporaries. This particular group of employees will be terminated once Trimble County is completed.[32] The use of the adjusted April 1990 labor capitalization rate proposed by LG&E is not acceptable. The adjustment of the rate to reflect what is expected to happen when Trimble County is commercialized is not appropriate. In light of the Commission's decision to include only the level of investment in Trimble County

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30 Kollen Direct Testimony, page 25.

31 Id., page 29.

32 T.E., Volume IV, November 19, 1990, page 268 and 269.

as of test-year end, it is not appropriate to use the estimated labor capitalization rate. However, we have used the actual labor capitalization rate for the last month of the test year, April 1990, without the Trimble County adjustment. The April 1990 labor capitalization rate was 32.09 percent[33] which reduces LG&E's test-year wages and salaries by $475,505.

<u>FICA Taxes</u>. LG&E proposed to increase its FICA taxes to reflect increases in total wages and salaries, a change in the FICA taxable wage base, and a change in the FICA tax rate. The Commission has reviewed LG&E's calculations for the FICA taxes. It appears that LG&E did not include in its calculations the effects of the November 1990 union wage increase. Wage adjustments and payroll tax adjustments should be determined in a consistent manner and reflect the same wage increases. Based on the Commission's decisions concerning the wage and salary adjustment, the FICA taxes have been recalculated which increases LG&E's test-year FICA taxes by $133,583.

<u>Unemployment Taxes</u>. In calculating its proposed increase to federal and state unemployment taxes, LG&E followed the methodology outlined by the Commission in Case No. 10064. The proposed adjustment is reasonable, except for the labor capitalization rate. Using the actual April 1990 labor

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33 Response to the Commission's Order dated June 29, 1990, Item 16(d), page 7 of 16, $3,314,676 / $10,330,308 = 32.09 percent.

capitalization rate, federal unemployment insurance should be increased $14,701 and state unemployment insurance should be increased $33,850 over the test-year actual expense.

Health Insurance. LG&E's proposed reduction in health insurance costs reflected its efforts in controlling its medical benefit costs, which had been an issue in LG&E's last two general rate cases. The AG opposed the use of the adjusted April 1990 labor capitalization rate in the calculation of this adjustment. Using the actual April 1990 labor capitalization rate, it is reasonable to reduce the test-year health insurance expense by $1,003,962.

Pensions. LG&E's proposed pension expense adjustment included the results of its latest actuarial study. The AG disagreed with incorporating the results of this study in the adjustment, stating that a change in wage assumptions was not an appropriate reason to ask ratepayers to bear the additional expense. The AG also opposed the use of the adjusted labor capitalization rate. Except for the labor capitalization rate utilized, the pension adjustment is reasonable, resulting in a $566,651 decrease in test-year pension expense.

Dental Insurance. The AG again opposed the use of the adjusted labor capitalization rate in determining the adjustment to dental insurance. The Commission believes that the dental insurance expense is reasonable, except for the labor capitalization rate utilized, and has determined the test-year dental insurance expense should be decreased by $7,909.

Group Life Insurance. In determining its proposed increase to group life insurance expense, LG&E followed the methodology outlined by the Commission in Case No. 10064. Included in the calculations were the total November 1990 union wage increase and the adjusted April 1990 labor capitalization rate. For the same reasons stated concerning the wage and salary adjustment, the AG opposed the inclusion of the union wage increase for the Trimble County project temporaries and the adjusted labor capitalization rate. In accordance with our decision on the wage and salary adjustment, we have excluded the union wage increase for the project temporaries and utilized the actual April 1990 labor capitalization rate in making this adjustment, which increases the test-year group life insurance expense by $206,187.

401(k) Thrift Savings Plan. Included in LG&E's test year expenses for labor-related costs was the employer's share of its 401(k) thrift savings plan ("401(k) plan"), which totalled $449,029. This amount represented LG&E's match to amounts deferred by its non-union employees who participated in the 401(k) plan. LG&E proposed no adjustment to the test-year expense. LG&E noted that the 401(k) plan was available only to non-union employees, and very little of the matching share amount would be appropriate to capitalize.[34]

The AG proposed to reduce the test-year expense to reflect the capitalization of the expense at the test-year actual labor

[34] T.E., Volume IV, November 19, 1990, pages 304 and 305.

capitalization rate, and that it was inappropriate to totally expense this item.[35]

The Commission's initial concern that LG&E had not adjusted the test-year expense to reflect the effects of its corporate reorganization, which occurred during the test year, was allayed by LG&E's schedule which showed the annualized test-year-end employer match to be $385,349.[36] We find it reasonable to include $385,349 in expenses for the 401(k) plan, which generates a reduction of $63,680 in test-year expense.

Supplemental Executive Retirement Plan. The AG proposed an adjustment removing the test-year expense of LG&E's Supplemental Executive Retirement Plan ("SERP"). The AG stated that the SERP was designated for certain key employees, and in light of the overall compensation and fringe benefits available to those employees, the costs of the SERP should not be borne by ratepayers. We agree, which reduces expenses by $247,922.

The Commission has noted in this proceeding several references by LG&E to its analysis and outside evaluations of portions of its labor and labor-related costs. In past orders the Commission has encouraged this type of evaluation, as did the management audit in several recommendations. However, LG&E has not yet performed an overall, comprehensive evaluation of its total compensation and fringe benefits package. Such an

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35 DeWard Direct Testimony, page 31.

36 Responses to Data Requests from Hearing, filed December 5, 1990, Item 18.

evaluation would compare LG&E's total compensation and fringe benefits package with other utilities as well as with other industries in its general service area. LG&E should undertake such an analysis of its total compensation and fringe benefits package as soon as possible.

Amortization of Downsizing Costs

During the last quarter of 1989, LG&E undertook a corporate reorganization which resulted in a workforce reduction of 174 exempt and non-exempt employees. Throughout this proceeding, this corporate reorganization has been referred to as a "downsizing." The costs associated with this downsizing totalled $9,486,550 and were composed of separation allowance payments, enhanced early retirement benefits, post-retirement health care provisions, and a gain on the purchase of retired employees' annuities.[37] LG&E proposed to amortize these costs over a 3-year period, and pointed out that the annual amortization would not exceed the expected annual savings resulting from the downsizing.[38]

The AG stated that LG&E had incurred or accrued these costs during the test year, had expensed these items during the test year, that these costs would not be occurring on a going forward basis,[39] and recommended removing the test-year downsizing costs in total and not allow amortization.

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37 Fowler Direct Testimony, page 18.

38 Id., page 19.

39 DeWard Direct Testimony, pages 28 and 29.

KIUC recommended that the downsizing costs be amortized over a 10-year period linked to the Commission's acceptance of KIUC's proposals concerning unbilled revenues. KIUC stated that if its proposals concerning unbilled revenues was not accepted, the Commission should disallow recovery of the downsizing costs as a matter of consistency.[40]

LG&E incurred and recorded the downsizing costs in the test year. LG&E has already recovered these costs from its ratepayers. While adjustments in its workforce will occur, it is highly unlikely that LG&E will be involved with a downsizing of this magnitude on a recurring basis. We have removed the entire $9,486,550 of downsizing costs for rate-making purposes.

Storm Damage Expenses

LG&E proposed an adjustment to increase storm damage expenses by $723,291. LG&E calculated its adjustment by averaging the actual storm damage expenses for the last 5 calendar years and comparing the average to the test-year actual expense. The methodology was essentially the same as was used by the Commission in Case No. 10064.

Jefferson et al. performed an analysis of LG&E's storm damage expenses for the past 15 years and determined that the test-year expense level was not below normal. Jefferson et al. arrived at the same conclusion using the 5-year period LG&E used but substituting two abnormal years with two normal years of expenses.

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40 Kollen Direct Testimony, page 25.

As the Commission noted in Case No. 10064, the random occurrence of severe storm damage cannot be accurately predicted. The Commission finds it is appropriate to include for rate-making purposes a level of storm damage expense which reflects a reasonable, on-going level of expense. Traditionally, the Commission has used historic averages in determining this reasonable level of expense. In this proceeding, the Commission has available the actual storm damage expenses for the past 15 calendar years. However, simply taking the average of an historic period would not recognize the effects of inflation when looking at such a long period of time. In Case No. 90-041[41] the Commission computed storm damage expenses by taking a 10-year average of actual expenses, adjusted for inflation by using the Consumer Price Index - Urban. We feel this approach the more reasonable and the preferred methodology to be used in determining this adjustment, which results in a $520,533 increase in storm damage expenses.

Provision for Uncollectible Accounts

LG&E proposed an increase of $100,000 to the test-year level of uncollectible accounts expense based on its analysis of the appropriate total annual provision. The proposed increase was determined using LG&E's actual 1990 accrual rate for the provision.

41 Case No. 90-041, An Adjustment of Gas and Electric Rates of the Union Light, Heat and Power Company, Order dated October 2, 1990.

Jefferson et al. opposed the increase to the expense, citing the fact that LG&E's actual charge-off history and accruals for uncollectible accounts over the past 5 years have experienced significant decreases in overall percentage.

The Commission believes it is best to leave the uncollectible accounts expense at the test-year level.

Location of Gas Service Lines

LG&E proposed an increase of $152,000 in expenses related to the location of customer owned service lines on private property. LG&E stated that this adjustment reflects the additional costs that it expects to incur as a result of placing temporary markings to locate customer service lines.[42] The Commission finds that LG&E has not adequately explained or supported the necessity for this proposed adjustment. Therefore, the Commission has not included the proposed increase in expense. The Commission is not attempting to limit this activity. However, in determining the reasonable level of expense on an on-going basis, consideration must be given to whether the activity involves an item which should be expensed or capitalized. LG&E did not provide specific evidence to allow a thorough analysis of this issue.

Headwater Benefit Assessment

LG&E proposed an increase of $108,033 in expenses to reflect the first year of a 3-year amortization of its Federal Energy Regulatory Commission ("FERC") headwater benefit assessment. The total amount of $324,098 reflects LG&E's initial FERC payment

[42] Fowler Direct Testimony, page 21.

pending LG&E challenges to FERC's original assessment of $3,600,000. LG&E recorded this payment as a deferred debit.

KIUC claimed that LG&E had no regulatory authority to defer this cost for future recovery. KIUC further stated that LG&E selectively identified this cost as recoverable since it was not specifically identified as an expense in its last rate case. Under established rate-making theory, LG&E must bear the risks and rewards of such costs as long as specific regulatory authority for differing treatment is absent. KIUC argues that by allowing this adjustment, the Commission would establish a precedential basis for future manipulation of actual earnings and improper increases in revenue requirements in future rate cases.

Given that LG&E has not heretofore recovered this payment from its ratepayers, we find it reasonable to allow LG&E to amortize the headwater benefit assessment over a 3-year period.

Depreciation and Amortization Expense

LG&E proposed to increase depreciation expense by $15,333,843 in order to annualize the test-year-end level of expense and to reflect the first year of depreciation expense on Trimble County. Of the total adjustment, $15,171,389 was for electric and $162,454 was for gas. Included in the annualization calculations were the effects of LG&E's recently completed depreciation studies of the electric and gas plant in service. The increase in the electric depreciation reflected first year depreciation expense based on estimated total cost of $715,000,000 adjusted for the 25 percent disallowance.

The AG, KIUC, and Jefferson et al. all opposed this inclusion stating that LG&E wanted to treat Trimble County in a vacuum,[43] that LG&E's proposed treatment lacked consistency,[44] and that LG&E's adjustment for Trimble County expenses did not meet the known and measurable standard.[45]

Although the first year depreciation expense based on the CWIP as of April 30, 1990 is allowed, supra, we do not include any depreciation expense on the additional expenditures incurred after test-year-end. This allowance, together with other components of LG&E's proposed adjustment we find reasonable and should be included in expenses, which results in increased depreciation and amortization expenses of $14,431,836, $14,269,382 electric and $162,454 gas.

Property Taxes

LG&E proposed to increase its property tax expense by $982,754 based on the 75 percent recoverable portion of the total expected expenditures for Trimble County estimated at $715,000,000.

The AG, KIUC, and Jefferson et al. opposed the proposed adjustment for the same reasons they expressed concerning the Trimble County depreciation adjustment.

Consistent with our other decisions relating to Trimble County, we have included a portion of the fixed costs of Trimble

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43 DeWard Direct Testimony, page 48.

44 Kollen Direct Testimony, page 19.

45 Kinloch Direct Testimony, page 11.

County to allow an increase in property taxes related to the balance of Trimble County CWIP as of April 30, 1990, which increases the test-year property tax expense by $931,857.[46]

EPRI Membership Dues

LG&E proposed an increase of $1,311,826 to expenses representing the projected 3-year average of the annual membership dues LG&E will pay the Electric Power Research Institute ("EPRI"). In order for LG&E to access the research and development programs and materials produced by EPRI, LG&E became a member of EPRI in July 1990. LG&E's evidence showed that the annual costs of its membership in EPRI would be offset by the benefits it receives from EPRI. The full membership dues are phased-in over a 3-year period, and LG&E's proposed adjustment reflects the average of those first 3 years' dues as calculated for 1990.

The AG opposed the proposed adjustment because LG&E had not quantified any cost savings attributable to its membership in EPRI. KIUC opposed the adjustment because LG&E had not proposed all appropriate pro forma adjustments. Jefferson et al. recommended the Commission withhold ratepayer support of EPRI until EPRI's restrictive membership policy is changed or, at a minimum, the Commission should exclude that portion of EPRI's dues relating to nuclear research.

LG&E should have quantified expected cost savings and included those offsetting savings. The payment of the membership dues was clearly a post-test year transaction and the benefits

46 Fowler Direct Testimony, Exhibit 1, Schedule E, line 3.

will likewise be reflected in reductions of future costs. In order to properly include the dues in this case, the cost savings expected from membership should have also been included. Because these expected savings were not shown, we feel compelled to exclude this proposed increase in expenses. The Commission realizes that utilities need to undertake research and development projects, and we are not opposed to including the costs of those projects when they are determined to be reasonable and benefits are demonstrated and factored into the proposed revenues and expenses.

EEI Membership Dues

During the test year, LG&E recorded as operating expense membership dues of $178,779 to the Edison Electric Institute ("EEI"). In Case No. 10064, the Commission excluded the membership dues to EEI because LG&E had failed to show that its membership in EEI was of direct benefit to its ratepayers.[47] The AG proposed to reduce the test year expense for various EEI-related activities it considered inappropriate. Jefferson et al. proposed that all EEI dues be removed from the test year because EEI was a utility industry lobbying organization. Although LG&E gave three examples of ratepayer benefits derived from its membership in EEI, it still has not adequately shown that there is a direct ratepayer benefit from membership in EEI. As LG&E acknowledged, all of the major benefits associated with EEI

[47] Case No. 10064, final Order dated July 1, 1988, page 60.

membership are available to LG&E independent of EEI. Further, EEI's lobbying activities are clearly a below-the-line expense.

New Office Expenses

In keeping with LG&E's position to exclude all costs associated with the relocation to the new corporate headquarters, an additional $2,489[48] in legal costs related to the headquarters relocation which were inadvertently included in the test year have been excluded.

Holding Company Expenses

In keeping with the Commission's Order in Case No. 89-374,[49] $6,612[50] in legal expenses incurred for the LG&E Energy Corporation ("Holding Company") included in test-year operating expenses has been disallowed.

Trimble County Marketing Costs

Test-year costs of $156,434[51] associated with marketing the 25 percent disallowed portion of Trimble County has been excluded, decreasing operating expenses by $156,323. The AG had proposed to remove $500,000 in Trimble County expenses, but produced no evidence to support his assumptions.

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48 Responses to Data Requests from Hearing, filed December 5, 1990, Item 9.

49 Case No. 89-374, Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith, Order dated May 25, 1990.

50 Responses to Data Requests from Hearing, filed December 5, 1990, Item 8.

51 LG&E Hearing Exhibit No. 16.

State Sales Taxes

LG&E proposed to increase its state sales tax expense by $163,000 to reflect the change in the Kentucky sales taxes rate effective July 1, 1990. Although KIUC opposed this adjustment on the grounds that LG&E had not made necessary the pro forma adjustments, The Commission believes it is reasonable to reflect this change in the state sales tax rate and has increased the state sales tax expense by $163,000.

Office Supplies and Professional Services Expenses

The AG proposed to reduce LG&E's test-year expenses for office supplies and professional services by $1,818,791. This amount represented a reduction to the levels recorded in the year prior to the test year. The AG argued that LG&E had failed to meet its burden of proof in justifying these expense increases, and advocated the Commission further decrease LG&E's test-year expenses to reflect information provided subsequent to the hearing as well as improper items of expense included by LG&E but not detected by the AG.[52]

The Commission has reviewed the account description in the Uniform System of Accounts ("USoA") for Account No. 921, Office Supplies and Expenses. This account can include charges for items such as printing, stationary, meals, traveling, and incidental expenses. However, expenses charged to any account must be evaluated on the reasonableness of the charge and how appropriate it is to include the charge for rate-making purposes. The charges

52 Brief of AG, page 1.

questioned by the AG were recorded in subaccounts of Account No. 921 which were periodically "zeroed out." Thus, these charges were not included in the test-year balance for Account No. 921. Given the information available, the Commission finds reasonable the test-year level of expense recorded in Account No. 921.

Concerning the professional services, LG&E has shown that it had already removed or reduced several of these charges in its pro forma adjustments. The Commission has specifically reviewed the invoices provided to the AG for test-year legal charges. LG&E edited many of these invoices and provided only very brief descriptions for the edited items. LG&E claimed that it could not disclose the nature of certain legal activities under the attorney-client privilege. The invoices included charges for numerous proceedings involving Trimble County and other major issues before or with the Commission. The Commission believes it is reasonable to remove the charges for the numerous Commission related proceedings since this level of activity should not be as large with the completion of Trimble County, on a going forward basis. We have also removed charges relating to the invoices where descriptions have been omitted, reducing test-year professional services expense by $294,676.

Miscellaneous Expense Adjustments

The AG proposed to reduce miscellaneous expenses by $314,903. Included in this proposed adjustment were contributions, economic development donations, moving expenses, and commitment fees recorded above the line, which the AG argues were not the ratepayers responsibility. The AG also argued that LG&E's

commitment fees should not be as high as in the past, since these fees had been related to the financing needs of Trimble County.

We have removed the contributions, economic development donations, and the moving expenses from the test-year expenses. The Commission traditionally has excluded above the line contributions and donations from rates; and we have not been persuaded that the moving expenses incurred in the test year represent a recurring item of expense. However, it is reasonable to include the test year level of commitment fees, because LG&E will be incurring commitment fees for its financing requirements on a recurring basis. Taken together this reduces test-year miscellaneous expenses by $151,507.

Amortization of Management Audit Fee

In Case No. 10064, the Commission approved LG&E's request to amortize the cost of the Management Audit over a 3-year period. This resulted in an annual amortization of $194,000.[53] As of the end of the test year, $226,333[54] remained to be amortized. At the present amortization rate, LG&E would have recovered the cost by the middle of 1991.

LG&E should recover the total cost of the management audit but it is not entitled to recover in excess of its cost, requiring the amortization rate to now be adjusted. The annual amortization rate for rate-making purposes should be $75,444 based on a 3-year amortization of the unamortized cost at test-year-end.

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53 Case No. 10064, Order dated July 1, 1988, page 62.

54 April 1990 Monthly Report, page 28.

Considering that the amortization has continued during the course of these proceedings, LG&E will recover its entire cost by the middle of 1992 at the $75,444 annual amortization rate. Test-year expenses have been reduced by $118,560 to reflect this adjustment.

Annualization of Year-End Customers

LG&E proposed an increase in operating expenses of $1,118,728 to reflect the increase in expenses related to annualizing the number of customers at test-year-end. This adjustment corresponded to a similar adjustment to operating revenues.

The AG proposed an increase in operating expenses of $947,065. The AG made several adjustments to the operating expenses used in the calculation of the proposal, stating that several expenses included by LG&E had not been shown to vary with the number of customers. The AG further stated that absent an LG&E study which showed that expenses increased with customer growth revenues, any adjustment based on an operating ratio is not known and measurable.[55]

The Commission specifically used the operating ratio methodology in Case No. 10064 and LG&E has followed that methodology in preparing its proposal. We have accepted LG&E's proposed adjustment.

Directors and Officers Liability Insurance

The AG proposed to reduce expenses by $245,943 to reflect the assignment of 50 percent of the cost of directors and officers liability insurance to the shareholders of LG&E. The AG argued

[55] DeWard Direct Testimony, page 33.

that the protection provided by the insurance was for both the shareholder and ratepayer. While there may be some benefits to shareholders, the main beneficiaries are the ratepayers. This insurance allows LG&E to induce highly qualified individuals to serve on its Board of Directors. We feel it is not proper or reasonable to include this adjustment.

Workers' Compensation Insurance

The AG proposed to reduce expenses by $536,187 to reflect a portion of the Workers' Compensation insurance expense recorded in the test year as capitalized. The AG stated that it was unclear whether LG&E was capitalizing any of the Workers' Compensation insurance costs, but that such an adjustment was appropriate. LG&E indicated that it was in fact capitalizing its Workers' Compensation insurance costs.[56] The Commission believes the amount included as workers' compensation insurance expense is reasonable.

Amortization of Investment Tax Credits

LG&E proposed to increase the amortization of investment tax credits ("ITC") by $1,554,000. The proposal reflected the change in depreciation rates used by LG&E and the amortization of ITCs attributable to Trimble County. The proposal reflected Trimble County ITCs for plant to be in service as of December 31, 1990.

The AG, KIUC, and Jefferson et al. opposed the inclusion of the Trimble County ITC amortization for the same reasons expressed

[56] T.E., Volume IV, November 19, 1990, page 185.

concerning LG&E's proposed adjustment to depreciation expense related to Trimble County.

As discussed earlier in this Order, it is reasonable to nclude Trimble County CWIP as of test-year end and the related first year depreciation expense in rates.‾ Likewise, it is reasonable to include the amortization on the Trimble County ITCs related to the April 30, 1990 balance of CWIP, which increases the amortization of ITCs by $1,507,000.[57]

Flowback of Unprotected Federal Excess Deferred Taxes

In Case No. 10064, the Commission ordered LG&E to amortize $4,749,500 in unprotected federal excess deferred taxes and $4,385,600 in state tax deficiencies over a 5-year period.[58] The AG claimed that LG&E did not appear to be in conformity with the Order in Case No. 10064 and proposed that the test year flowback of the unprotected federal excess deferred taxes be increased by $162,300. LG&E stated that it had changed the amount of the federal amortization due to the discovery of some errors in the amounts originally provided to the Commission in Case No. 10064, but even after the discovery of these errors, it had not informed the Commission of the change. LG&E filed information concerning the change in the amount of unprotected excess deferred taxes and its change in the amortization amount.

The Commission has reviewed the account information. It appears that both amortization amounts have been changed, not just

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57 Fowler Direct Testimony, Exhibit 1, Schedule Y, line 5.

58 Case No. 10064, Order dated July 1, 1988, page 61.

the amortization for the federal excess deferred taxes. Insufficient information has been provided to justify a change in the federal amortization as ordered in Case No. 10064. The flowback of unprotected federal excess deferred taxes is restored to the level ordered in Case No. 10064 by $162,300.

State Income Tax Rate Change

LG&E proposed three adjustments to reflect the change in the Kentucky income tax rate, which became effective January 1, 1990. The adjustments were an increase in state income tax of $508,000; an increase in deferred state income tax of $42,000; and an increase in the amortization of cumulative state deferred tax of $512,000. In all three adjustments, LG&E computed the corresponding savings in federal income taxes relating to the state income tax rate change.

The methodology used to reflect the change in the state income tax rates is reasonable. But, based on the information provided, these adjustments require recalculations to reflect the level of state tax deficiency identified in Case No. 10064. The state income tax is increased by $508,000; deferred state income tax increased by $41,473; and the amortization of cumulative state deferred tax increased by $446,582.

Tax Adjustment for Other Interest Expense

LG&E proposed to increase income tax expense by $198,430 to reflect the income taxes applicable to other interest expense. In Case No. 10064, the Commission determined that LG&E could not recover other interest expense from ratepayers. Because LG&E could not recover this expense from ratepayers, LG&E claims that the ratepayers should not receive any corresponding income tax benefits. We do not agree. According to the USoA, other interest expense is recorded below the line.

It is not proper to make the proposed adjustment to income tax expense without supporting documentation which shows LG&E included other interest expense in the determination of its above-the-line income tax expense.

Interest Synchronization

LG&E proposed two adjustments in order to determine its interest synchronization. The first adjustment annualized the interest expense on debt, and the second reflected the allocation of JDIC on the computation. Traditionally, the Commission has applied the cost rates applicable to the long-term debt and short-term debt components of the capital structure in order to compute an interest adjustment. This was the approach the Commission used in Case No. 10064. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the 25 percent Trimble County disallowance and the capital costs of LG&E's new office building. Using the adjusted capital structure allowed, the Commission has computed an interest reduction of $1,193,023 which results in an increase to income taxes of $470,588.

Following the approach used in Case No. 10064, the Commission has applied the combined state and federal income tax rate of 39.445 percent to the accepted pro forma adjustments. The Commission finds that combined operating income should be increased by $6,639,060 to $130,376,955.

The adjusted net operating income is as follows:

	Electric	Gas	Total
Operating Revenues	$502,388,881	$183,296,032	$685,684,913
Operating Expenses	384,835,893	170,472,065	555,307,958
ADJUSTED NET OPERATING INCOME	$117,552,988	$ 12,823,967	$130,376,955

RATE OF RETURN

Capital Structure

LG&E proposed an adjusted end-of-test-year capital structure containing 43.13 percent long-term debt, 4.69 percent short-term debt, 8.22 percent preferred stock, and 43.96 percent common equity. Year-end, long-term debt was adjusted to reflect: (1) the retirement of $16,000,000 of 4 7/8 percent First Mortgage Bonds, Series due October 1, 1990;[59] (2) the scheduled redemption of $750,000 of 1975 Pollution Control Bonds due September 1, 1990;[60] and (3) the refinancing of $25,000,000 of Series J 1985 Pollution Control Bonds at 8.25 percent interest with 1990 bonds at 7.45 percent interest.[61] The retirement of the $16,000,000 of 4 7/8 percent First Mortgage Bonds and the redemption of the $750,000 1975 Pollution Control Bonds were reflected as adjustments to short-term debt. The refinancing of the 1985

59 Fowler Direct Testimony, Exhibit I, Schedule V.

60 Id.

61 T.E., Volume IV, November 19, 1990, page 11.

Series J Pollution Control Bonds with 1990 bonds did not affect the capital structure.

LG&E decreased year-end preferred stock and increased common equity by $1,033,459, the discount and expense associated with the preferred stock issues.[62] LG&E also decreased common equity by $9,251,593 to reflect the adjustment to retained earnings for unbilled revenues as discussed previously in this Order.[63]

The AG proposed a capital structure containing 43.11 percent long-term debt, 4.69 percent short-term debt, 8.30 percent preferred stock, and 43.90 percent common equity.[64] The difference in the AG's proposal and LG&E's proposal is that the AG proposed to exclude unamortized premiums, discounts, and expenses. The AG claims these amounts are not a part of the permanent financing of a utility. Moreover, the AG disagreed with LG&E's adjustment to place the preferred stock discount and expense in the weighted average of preferred stock.[65] The AG maintained that the preferred stock discount and expense was properly recorded in the capital stock account and should remain in the weighted average of common equity.

Premiums, discounts, and other expenses of issuing securities are an integral part of the financing of a utility and should be

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62 Fowler Direct Testimony, page 1 of 2.

63 Id., page 1.

64 Weaver Direct Testimony, Exhibit, Statement 17.

65 Id., page 30.

reflected as such in the capital structure. LG&E's adjustment to place the discount and expenses associated with preferred stock in the preferred stock structure is appropriate. The Commission finds LG&E's capital structure is as follows:

	Percent
Long-Term Debt	43.13
Short-Term Debt	4.69
Preferred Stock	8.22
Common Equity	43.96
Total Capital	100.00%

Cost of Debt and Preferred Stock

LG&E proposed a cost of long-term debt of 7.72 percent after adjustments for the refinancing of the $25,000,000 1985 First Mortgage Bonds.[66] The AG proposed a cost of long-term debt of 7.79 percent[67] but did not include an adjustment for refinancing the 1985 First Mortgage Bonds. To arrive at its cost of long-term debt, LG&E included the unamortized premium on bonds in long-term debt and adjusted interest expense by the amortization of expenses, premiums, and the loss on reacquired debt.[68] The AG did not include the unamortized premium on bonds in long-term debt and adjusted interest expense by the amortization of the expenses and

66 Calculated from Fowler Direct Testimony, Exhibit 2, page 1; and T.E., Volume IV, November 19, 1990, page 11.

67 Weaver Response to LG&E, 17.

68 Fowler Direct Testimony, Exhibit 2, page 1; and Exhibit 1, Schedule V.

premium but did not adjust interest expense by the amortization of the loss on reacquired debt.[69]

It is more appropriate to adjust long-term debt by the unamortized premium on bonds and to adjust interest expense by the amortization of the loss on reacquired debt. We find the cost of long-term debt to be 7.72 percent.

LG&E proposed the cost of short-term debt to be 8.38.[70] The AG proposed the cost of short-term debt to be 8.43.[71] The AG subsequently agreed with a cost of 8.38, and the Commission concurs.

LG&E[72] and the AG[73] both agreed that the cost of preferred stock is 8.09 percent and the Commission concurs.

Return on Equity

LG&E proposed a return on equity ("ROE") in the range of 13.0 to 13.5 percent,[74] and subsequently revised its expected cost of equity to be in the range of 13.25 to 13.75 percent.[75] The AG proposed a range of 12.0 to 12.5 percent.[76] KIUC proposed an ROE

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69 Weaver Direct Testimony, Exhibit, Statement 15.

70 Fowler Direct Testimony, Exhibit 2, page 1.

71 Weaver Direct Testimony, Exhibit Statement 16, page 2.

72 Fowler Direct Testimony, Exhibit 2, page 1.

73 Weaver Direct Testimony, Exhibit, Statement 17.

74 Olson Direct Testimony, page 36.

75 Olson Supplemental Testimony, page 18.

76 Weaver Direct Testimony, page 28.

of 11.7 percent.[77] Jefferson et al. proposed an ROE in the range of 11.0 to 11.5 percent.[78]

To determine the ROE, LG&E used a discounted cash flow ("DCF") analysis. In addition, LG&E utilized an interest premium calculation and DCF study of eight other electric utilities as a check on the results of its DCF analysis. LG&E adjusted the results for financing costs and to show additional margin.

In its DCF analysis, LG&E used a dividend yield of 7.57 percent[79] based on a projected dividend rate of $2.84 and a 6-month high/low stock price average during the period May 1 - October 26, 1990.[80] LG&E relied on three methods of analysis to determine its estimated growth rate: 1) a study of past and current trends in dividends, earnings and book value; 2) retention or internal growth; and 3) estimates of expected growth available from security analysts.[81] Based on its analysis, LG&E opined that investors expect growth of 4.75 to 5.25 percent.[82] Overall, LG&E's DCF analysis produced a return requirement of 12.32 to 12.82 percent.[83]

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77 Baudino Direct Testimony, page 26.

78 Kinloch Direct Testimony, page 22.

79 Olson Supplemental Testimony, page 17.

80 Id.

81 Olson Direct Testimony, page 23.

82 Id., page 29.

83 Olson Supplemental Testimony, page 17.

Using an interest premium approach as a first check on its DCF analysis, LG&E concluded its cost of common equity to be 14.5 percent. The risk premium of investors was estimated to be 4.75 percent. This was added to the current yield to maturity on Double A bonds of 9.8 percent.[84] As a second check of its results, LG&E performed a DCF study of eight selected utilities. The results indicated an investor requirement of 12.48 to 12.98 percent.[85]

LG&E determined that the results of its DCF analysis were not in fact the returns required by investors. LG&E applied an 8 percent premium to its DCF results to compensate for financing cost and market pressure.[86] LG&E concluded that its required ROE should be 13.25 to 13.75 percent.[87]

To perform a DCF analysis, the AG selected 5 companies he considered to be of comparable risk to LG&E. The companies considered were combination gas and electric companies reported in <u>Value Line</u> with characteristics similar to LG&E in capital structure ratios, total assets, fuel mix, electric vs. gas revenue distribution, betas, stock ratings, and bond ratings.[88] According to the AG's analysis, LG&E has a slightly greater amount of risk from its capital structure and operating leverage than the

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[84] Olson Direct Testimony, pages 32-33.

[85] Olson Supplemental Testimony, page 18.

[86] Olson Direct Testimony, page 36.

[87] Olson Supplemental Testimony, page 18.

[88] Weaver Direct Testimony, page 6.

comparison group but this risk is offset by the greater risk of the comparison group from acid rain legislation.[89]

The AG used four methods of calculating growth for its DCF analysis. The methods used were: 1) compound growth rate in dividends per share; 2) compound growth rate in earnings per share; 3) compound growth rate in book value per share; and 4) earnings retention ratio multiplied by ROE. Based on these calculations, the AG's recommended growth rate was 4.0 to 4.5 percent.[90]

The AG calculated a dividend yield from June 29, 1990 through September 7, 1990 of 7.44 percent for LG&E and 7.75 percent for the comparison group.[91] The AG employed these yields in its DCF analysis to reflect greater uncertainty caused by the Middle East situation.[92] The results of the AG's DCF analysis yielded an ROE for LG&E of 11.74 to 12.27 percent and 12.06 to 12.60 percent for the comparable companies.[93] Based on these results the AG determined LG&E's required ROE to be within a range of 12.0 to 12.5 percent.[94]

KIUC performed a DCF analysis using the same eight companies that LG&E used in its DCF study of comparable companies and a risk

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89 Id., page 18.

90 Id., page 25.

91 Id., page 26.

92 Id.

93 Id., page 27.

94 Id., page 28.

premium analysis. KIUC calculated a 6-month average dividend yield during the period from February through July 1990 of 7.22 percent for the comparison group[95] and 7.28 percent for LG&E.[96] Averaging the Institutional Brokers Estimate System ("IBES") earnings growth project, Value Line compound dividend growth rate from 1990 to 1994, and Value Line compound earnings per share growth rate from 1990 to 1994 resulted in an expected growth rate of 4.28 percent for the comparison group[97] and 3.46 percent for LG&E.[98] To complete the DCF equations, KIUC applied one-half the growth rate to the historical dividend yields to arrive at a ROE for the comparison group of 11.65 percent[99] and 10.87 percent for LG&E.[100] KIUC opined that its DCF cost of equity for LG&E was too conservative given the DCF cost of equity for the comparison group.[101] KIUC found the comparison group results were not understated based on a sustainable growth calculation it performed as a check.[102]

In addition, KIUC performed a risk premium analysis as a supplementary check on its DCF analysis. Adding a risk premium of

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95 Baudino Direct Testimony, page 11.

96 Id., page 18.

97 Id., page 13.

98 Id., page 19.

99 Id., page 16.

100 Id., page 20.

101 Id., page 21.

102 Id., page 25.

2.11 percent to the 9.65 percent average yield of LG&E's first mortgage bonds for February and July 1990 resulted in a cost of equity for LG&E of 11.76 percent.[103] In its final analysis, KIUC averaged the results of its DCF for comparison companies and its risk premium analysis to arrive at its estimate of 11.7 percent as a fair rate of return for LG&E.[104]

Jefferson et al. opined that an ROE between 11.0 and 11.5 percent would offer LG&E's shareholders a fair return on their investment.[105] This was based on a review of returns recently granted by other Commissions as published in Public Utilities Fortnightly and KIUC's assessment of LG&E's level of risk as compared to the named utilities.

The 8 percent premium proposed by LG&E to adjust for flotation cost and market pressure would overstate LG&E's cost of capital. LG&E is rated a solid Aa/AA by Moody's and Standard and Poor and thus can be considered less risky than the average utility investment. Pressure to finance ongoing construction is declining and by its own admission, LG&E is in a one-of-a-kind position to perform under the Clean Air Act. However, the current state of the economy is timorous. The Commission, having considered all of the evidence, including current economic conditions, finds that an ROE of 12.25 to 12.75 percent is fair, just, and reasonable. An ROE in this range would allow LG&E to

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103 Id., page 24.

104 Id., page 26.

105 Kinloch Direct Testimony, page 22.

attract capital at a reasonable cost and maintain its financial integrity to ensure continued service and provide for necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers. A return of 12.5 percent will best meet the above objectives.

Rate of Return Summary

Applying the rates of 7.79 percent for debt, 8.09 percent for preferred stock, and 12.50 percent for common equity to the capital structure produces an overall cost of capital of 9.89 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on LG&E's net original cost rate base of 9.52 percent which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $3,618,915 to produce a rate of return of 12.50 percent on common equity based on the adjusted historical test year. After the provision for state and federal taxes, there is an overall revenue deficiency of $5,976,245 the amount of additional revenue granted. The net operating income necessary to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $133,995,870. A breakdown between electric and gas operations of the required operating income and the increase in revenue allowed is as follows:

	Electric	Gas	Total
Net Operating Income Found Reasonable	$120,854,300	$ 13,141,570	$133,995,870
Adjusted Net Operating Income	117,552,988	12,823,967	130,376,955
Net Operating Income Deficiency	3,301,312	317,603	3,618,915
Gross Up Revenue Factor for Taxes [1.00-.39445]	.60555	.60555	.60555
Additional Revenue Required	5,451,758	524,487	5,976,245

The additional revenue granted will provide a rate of return on the net original cost rate base of 9.52 percent and an overall return on total capitalization of 9.89 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $691,661,158. These operating revenues include $507,840,639 in electric revenues and $183,820,519 in gas revenues. The gas operating revenues reflect the most recent gas cost adjustment approved in Case No. 10064-J.

PRICING AND TARIFF ISSUES

Electric Cost-of-Service Study

LG&E presented a fully embedded time-differentiated electric cost-of-service study for the purpose of allocating costs among the classes of service on the basis of cost incurrence. The study used a base-intermediate-peak ("BIP") method to allocate production and transmission costs to costing periods and to customer classes. The BIP methodology, which was approved by the

Commission in Case Nos. 8616,[106] 8924,[107] and 10064,[108] was described by LG&E in the following manner:

> The cost assignments to the base period were established on the basis of the relationship of the minimum demand to the maximum demand. This recognized that some level of capacity is always present to meet customer needs. Base costs were allocated among classes based on their individual contribution to the average system demand. Intermediate peak costs were determined on the basis of the maximum winter peak demand over and above the average demand. Such costs were then assigned to the winter peak period based on the relationship of the number of hours in that period to the total hours in both the winter and summer peak periods. Costs were then allocated among customer classes according to each class's contribution to the winter peak demand. The remaining production and transmission costs were assigned to the summer peak period and allocated on the basis of each class's contribution to the summer peak demand.[109]

All other electric cost-of-service methodologies used by LG&E are essentially the same as those approved by the Commission in LG&E's last two rate cases.

KIUC recommended that demand-related costs be allocated to customer classes using the Probability of Peak ("POP") method. This method represents a type of coincident peak allocation in which each class's contribution to the utility's twelve monthly

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[106] Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Order dated March 2, 1983, pages 33-34.

[107] Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Order dated May 16, 1984, pages 37-38.

[108] Case No. 10064, Order dated July 1, 1988, pages 81-84.

[109] Walker Direct Testimony, pages 11-12.

system peaks are weighted by a given month's relative probability of attaining the annual system peak.[110] KIUC concluded that LG&E's electric cost-of-service study could not be used because it does not properly assign costs to customer classes. KIUC argued that the BIP method is deficient because it allocates a portion of demand-related production and transmission costs on an energy basis and assigns too much of the remaining weight to LG&E's winter system peak.[111]

According to LG&E, the POP method proposed by KIUC results in an assignment of nearly 90 percent of the weight of production and transmission costs to the coincident peaks that occurred during the summer months of July and August, with over 97 percent assigned to the June-September period.[112] LG&E further contended that the POP method leads directly to a class allocation in which the lighting schedules, Rates PSL, OL, and SLE, are assigned no portion of the production and transmission demand-related costs even though customers served under those rate schedules have access to power whenever they desire it.[113] KIUC even stated that "demand-related fixed costs are incurred due to the utility's obligation to provide service when requested".[114] LG&E stated that the BIP method is superior to the POP method in reflecting

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110 Kalcic Direct Testimony, page 11.

111 Id., page 10.

112 Brief of LG&E, page 122.

113 Id., pages 122-123.

114 Kalcic Direct Testimony, page 8.

the realities of cost incurrence on its system and should be used in the analysis of cost of service.[115]

The Commission continues to believe that the BIP method is appropriate as a means of allocating production and transmission costs to the customer classes. The BIP method recognizes that LG&E's embedded production and transmission costs were incurred to meet all customer demand, not just that which is coincident with system peak. KIUC's proposed POP method places too much weight on coincident peak demand. If any customer has access to electricity whenever it is demanded, that customer should bear the responsibility of some portion of demand-related costs.

LG&E's electric cost-of-service study is acceptable and should be used as a starting point for electric rate design.

Gas Cost-of-Service Study

LG&E filed a fully embedded gas cost-of-service study to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each rate class makes to overall return on net rate base. Pursuant to a Commission directive in Case No. 10064, LG&E disaggregated its customers in this cost-of-service study into the following classes: Residential Rate G-1, Commercial Rate G-1, Industrial Rate G-1, Commercial Rate G-6, Industrial Rate G-6, and Fort Knox

[115] Brief of LG&E, page 123.

Special Contract.[116] For purposes of this study, LG&E combined the sole customer served under Uncommitted Gas Service Rate G-7 with Industrial Rate G-6.[117] LG&E stated, however, that the provision of service to Rate G-7 customers is markedly different from that provided to Rate G-6 customers.[118]

LG&E did not disaggregate the customer classes further into transportation and sales categories. LG&E contended that since all transportation customers may purchase any portion of their annual gas requirements under the applicable sales rate schedules, and since all but one of its transportation customers purchased sales gas during the test year, a disaggregation of transportation customers would be unnecessary.[119]

LG&E's cost-of-service model consists of the following steps: (1) costs are assigned to the major functional groups (underground storage, transmission, distribution general, distribution structures, distribution mains, distribution services, distribution meters, customer accounting, and customer services); (2) functionalized costs are then classified into demand, commodity, and customer components; and then (3) classified costs

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116 In the Commission's Order in Case No. 10064 dated July 1, 1988, at page 81, LG&E was directed to address, in its next rate case, an assertion made by KIUC that LG&E's cost-of-service study did not fully disaggregate its various classes of customers.

117 Walker Exhibit 2, page 1.

118 Id.

119 Brief of LG&E, page 125.

are allocated to LG&E's rate classes.[120] LG&E's gas cost-of-service methodologies are consistent with those approved by the Commission in Case No. 10064.

The AG criticized several allocation methodologies used by LG&E and suggested alternative allocation factors. The AG, however, did not conduct a cost-of-service study incorporating his recommended allocation factors.[121]

The AG proposed to allocate exactly half of the demand-related underground storage and transmission costs on the basis of extreme winter seasonal requirements and design-day demand, the same factor LG&E used to allocate all of the storage and transmission demand costs in its cost-of-service study. The AG recommended that the other half be allocated on the basis of total class usage.[122]

Similarly, the AG proposed to allocate half of the commodity-related storage and transmission costs on the basis of design-day demand, with the other half allocated on the basis of total class usage.[123]

The AG proposed to allocate one-third of the costs associated with distribution structures and equipment on the basis of class

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120 Walker Exhibit 2, page 2.

121 T.E., Volume VII, November 26, 1990, pages 12-13.

122 Sheehan Direct Testimony, pages 10-11.

123 *Id.*, page 12.

design-day demand, with the remaining two-thirds allocated on the basis of total class usage.[124]

Finally, the AG recommended substituting a usage-based allocator or a different customer-based allocator for LG&E's customer-based allocator for the allocation of costs associated with customer accounting and customer service expenses.[125]

The AG has provided no evidence to support the reasonableness of his cost-of-service allocation methodologies. In fact, when asked to explain the basis for one of his proposed methodologies, the AG's witness vaguely characterized it as "rule of thumb" and "reasonable at a first glance."[126] He also indicated that some of his other recommended methodologies could be similarly described.[127] Explanations such as that hardly support the reasonableness of the AG's recommended allocation methodologies. Furthermore, the AG is unable to quantify the effect his recommendations will have on class rates of return.[128] Considering the lack of support for the AG's recommendations, the Commission is unable to adopt them as alternatives to LG&E's allocation methodologies.

KIUC criticized LG&E's gas cost-of-service study because it does not establish separate classes for transportation customers

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124 Id., page 14.

125 Id., pages 16-19.

126 T.E., Volume VII, November 26, 1990, page 54.

127 Id., pages 55-56.

128 Id., page 58.

and sales customers. It contended this absence renders the study useless with respect to the design of cost-based transportation rates.[129]

KIUC asserted that the cost incurrence characteristics of transportation service are significantly different from those of sales service based on an analysis of load factor and customer size data for G-1 and G-6 sales and transportation customers. KIUC contended that the larger load factors and customer sizes of transportation customers indicate "radically different" cost incurrence,[130] and asserted that the gas cost-of-service study should disaggregate transportation customers from sales customers.

KIUC presented an alternative gas cost-of-service study in which commercial and industrial G-1 and G-6 customers are disaggregated further into separate sales classes and transportation classes. With respect to the allocation methodologies utilized to assign costs to these classes, KIUC adopts the same methodologies employed by LG&E in its study.[131]

KIUC's reliance on load factor and customer size data to prove a significant difference in cost incurrence characteristics is not sufficient to convince the Commission that such an extreme cost differential exists. LG&E has clearly shown that all but one of its transportation customers also relied upon and used sales

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[129] Eisdorfer Direct Testimony, page 3.

[130] Id., page 6.

[131] Id., pages 8-9.

service to some degree during the test year.[132] This ability of transportation customers to rely upon and use sales services is a privilege not adequately considered by KIUC in its analysis. Nor does KIUC's analysis acknowledge that LG&E's distribution system is constructed in a manner so as to provide sales service to these customers whenever such service is demanded. These factors must be considered when attempting to determine differences in cost incurrence characteristics between customers. KIUC's evidence lacks such consideration and analysis.

LG&E has stated that certain differences exist in the provision of service to Rate G-6 customers and Rate G-7 customers.[133] Yet LG&E combined its one G-7 customer with the Rate G-6 class for purposes of its cost-of-service study. LG&E should, in subsequent cost-of-service studies, fully disaggregate Rate G-7 customers from those served under Rate G-6.

LG&E's gas cost-of-service study is acceptable and should be used as a starting point for gas rate design.

Revenue Allocation

Based on the results of its electric cost-of-service study, LG&E proposed to allocate increases to all customer classes ranging from 7.4 percent for the residential and street and outdoor lighting classes to 5.9 percent for the general service and special contract classes. LG&E indicated that its allocation

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132 T.E., Volume VII, November 26, 1990, page 93.

133 Walker Exhibit 2, page 1.

methodology was designed to achieve a better balance between class rates of return while maintaining rate stability and continuity.

LG&E proposed to allocate the full amount of the gas increase to the General Service ("G-1") rate. This proposal was based on the results of LG&E's cost-of-service study which showed that the rate of return for the residential class, which is served under the G-1 rate schedule, was significantly below rates of return for other classes. LG&E proposed no increases for its interruptible rate classes, G-6 and G-7, or for the Fort Knox special contract.

KIUC, based on its electric cost-of-service study, proposed allocations ranging from a 5.6 percent decrease for Carbon Graphite, a contract customer, to a 13.1 percent increase for the residential class. On gas, KIUC proposed decreases for G-1 and G-6 industrial transportation customers. The amount of the decreases were dependent on the amount by which the Commission reduced LG&E's requested gas increase. None of the other intervenors offered specific allocation recommendations.

LG&E's allocation proposals are supported by its cost-of-service analyses and are consistent with the Commission's goals of gradualism and rate continuity. Having accepted LG&E's cost-of-service studies, the Commission finds that the resulting allocation proposals produce an equitable distribution of the revenue increases granted and shall be reflected in the rate design approved herein.

Electric Rate Design

LG&E proposed generally uniform increases in customer, demand and energy charges with some changes in its existing tariffs and rate design. The changes included: switching from a minimum bill to a customer charge for its water heating, space heating, and traffic lighting rates; changes in demand ratchets that would impact the billing demands for large commercial and industrial customers; seasonal billing demands for industrial customers served under rate LP; and making time-of-day rates available for smaller sized industrial and commercial customers. In addition, LG&E proposed changes in Public Street Lighting ("PSL") and Outdoor Lighting ("OL") rates to equalize the prices, by lumens of output, between mercury vapor and high pressure sodium lights. LG&E also proposed to revise its interruptible service rider by increasing the monthly demand credit to $3.30 per KW.

Louisville opposed LG&E's proposed changes to the PSL rates contending that the marginal cost pricing methodology employed by LG&E unfairly impacted Louisville with its older, more fully depreciated street lighting system. Louisville recommended an alternative rate schedule based on embedded costs and proposed to be separated from LG&E's other PSL customers either through a special contract or by establishing a separate tariff classification.

Jefferson et al. proposed changing LG&E's residential rate structure from a flat summer rate and declining block winter rate to inverted block rates in both summer and winter. Jefferson et al. opines that LG&E was deficient in its response to the Commission's directive in Case No. 10064 that LG&E address the issues of inverted block rates in the summer and declining block winter rates.[134] Jefferson et al., based on its analysis of LG&E's cost-of-service study, contends that LG&E's temperature-sensitive loads (summer air conditioning and winter heating) have a major impact on LG&E's costs and the allocation of those costs. Jefferson et al. proposes that LG&E's cost recovery, through rates, should also reflect the impact of these temperature-sensitive loads.

Jefferson et al.'s proposal would reduce LG&E's energy rate for the first 600 KWH to 5.435¢ on a year-round basis compared to LG&E's existing rates of 6.402¢ and 5.833¢ in the summer and winter, respectively. Jefferson et al. would increase the rate for sales over 600 KWH to 8.189¢ in the summer and 6.227¢ in the winter compared to the existing rates of 6.402¢ in summer, and 4.528¢ in winter. These rates were based on Jefferson et al.'s analysis of LG&E's temperature-sensitive costs using the base, winter, and summer demands from LG&E's cost-of-service study and using one month of the test year, October 1989, as the measure of LG&E's non-temperature-sensitive load.

LG&E argues that while unit costs are higher in the summer than in the winter there is no load research evidence to support Jefferson et al.'s proposal. LG&E contends that its existing rate design reflects the differences in summer and winter unit costs and, through the declining block winter rate, attempts to reduce the average unit cost by spreading fixed costs over greater sales volumes. LG&E further contends that deficient recovery of

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[134] Case No. 10064, Order dated August 10, 1988.

customer costs through the customer charge requires these costs to be recovered in the initial usage steps to prevent large users from paying a disproportionate share of these costs. Finally, LG&E argues that its declining block winter rates should be continued to promote off-peak loads and that customer acceptance and revenue stability must be included in any consideration of rate design changes.

The Commission finds most of LG&E's rate design changes proper and reasonable. On PSL and OL rates, the Commission finds LG&E's alternative proposal proper and reasonable. The alternative proposal, to which Louisville agreed, results in approximately equal percentage increases for existing lights, be they mercury vapor or high pressure sodium.[135] For mercury vapor lights installed in the future, the rates would be higher, based on LG&E's marginal costs, while for new high pressure sodium lights the rates would equal the rates for existing lights.

The Commission is not persuaded that LG&E's residential rates should be redesigned in the precise manner proposed by Jefferson et al.; however, we find that a change resulting in an inverted block summer rate is appropriate. The Commission finds there to be substantial support for Jefferson et al.'s proposed inverted summer rates. LG&E is a strong summer peaker with a significant amount of capacity installed to meet its residential air conditioning load. As LG&E pointed out, its unit costs are higher in the summer than in the winter largely due to the relatively

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[135] T.E., Volume V, November 20, 1990, page 111.

small increment of energy sales associated with the capacity required to meet its air conditioning demands.[136] These summer load characteristics indicate that LG&E's temperature- sensitive load is a major contributor to its generating and transmission costs and point out the need for long-term reductions in peak demand that can translate into lower future costs.

The Commission considers reduced peak demand, improved system load factor, and lower unit costs to be common goals that are in the best interest of all parties. To that extent, we are not persuaded that LG&E's winter rate design should be modified. Increased off-peak loads can produce many of the same benefits as reduced on-peak loads.

In recognition of concerns about cost recovery, customer acceptance, and revenue stability we have chosen a moderate approach to the implementation of an inverted block summer rate. The summer energy rate will remain unchanged for the first 600 KWH usage; the summer energy charge increase will be assigned in total to the usage in excess of 600 KWH. Given the relatively small number of KWH sold in relation to the capacity needed to meet air conditioning demands, this increase should not affect LG&E's revenue stability.

Cable Television Attachment Charges ("CATV")

LG&E proposed increasing its charges for CATV pole attachments by approximately 35 percent. LG&E's calculation of these charges was based on the formula established by the

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[136] Walker Direct Testimony, page 22.

Commission in Administrative Case No. 251[137] with an added cost component for tree trimming expense.

KCTA opposed the increase contending that LG&E's allocation of the entire amount of tree trimming expense included in Account 593.004, Tree Trimming of Electric Distribution Routes, to poles was improper. KCTA opined that the vast majority of the expense goes not to clear space for poles, but to clear space for LG&E's overhead conductions and services and for clearing a path for the span of lines between the poles. KCTA proposed allocating the tree trimming expense based on LG&E's investment in poles compared to its combined investment in poles, overhead conductors, and services thereby increasing LG&E's pole attachment charges by approximately 14 percent. KCTA also proposed that the approved pole attachment rates be calculated using the overall rate of return approved by the Commission in this case.

LG&E argued that since the cable television lines are strung between the poles, those lines are benefited by the tree trimming that clears the path between the poles. LG&E also pointed out that pole attachment charges are assessed through a formula, based on the percentage of usable space, that uses an allocation factor to derive the appropriate charge.

The clearing of the span between the poles inures to the benefit of all parties whose lines cover the span, be they

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137 Administrative Case No. 251, The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments, Order dated August 12, 1982.

electric, telephone, or CATV. As such, the full amount of the tree trimming expense is properly includible in calculating the O & M component of the annual carrying cost used to derive the pole attachment charge. Applying the annual carrying charge to an allocated fix cost component, derived using the percentage of usable space, effectively allocates the O&M component of the annual carrying charge. The result is a pole attachment charge which reflects an equitable allocation and recovery of LG&E's costs. The pole attachment charges proposed by LG&E, modified to reflect the overall rate of return of 9.89 percent, are granted.

Gas Rate Design

For the G-1 class, LG&E proposed to increase customer charges by approximately 24 percent and commodity charges by approximately 1.8 percent. This proposal reflected the results of LG&E's cost-of-service study and the need to improve the residential rate of return. LG&E maintains that since the average residential usage is significantly smaller than the usage of the commercial and industrial classes served under Rate G-1, the customer charge, rather than the commodity charge, is the appropriate rate to increase for the purpose of achieving a better balance between class rates of return.

The AG opposed the proposed increase in the residential customer charge from $4.35 to $5.40, taking issue with several of LG&E's cost allocators used in arriving at its customer costs. The AG argued that the proposal acted as a disincentive for conservation by placing the bulk of the increase on the fixed portion of the customer's bill. The AG calculated a customer cost of $3.75 and opined that the existing charge of $4.35 was more than adequate.

Jefferson et al. maintained that the customer charge increase would overly burden the small, lower income customers in the residential class. Jefferson et al. argued that LG&E's stated intention of increasing the residential class rate of return was improper because the lower risk associated with serving the residential class should translate into a lower rate of return. Jefferson et al. proposed a rate design that included increasing the customer charge by 2.4 percent, the amount of the overall requested G-1 rate increase.

Although LG&E's proposal for increasing the customer charge may be logical and reasonable, the amount of the increase is not consistent with the Commission's goals of rate continuity and gradualism. While there is a lower risk associated with serving the residential class some increase in the residential class rate of return is warranted. As a means of achieving this increase in return, it is proper to assign the majority of the revenue increase to the customer charge. Given the magnitude of the increase, the Commission will assign the customer charge an increase of approximately 2.5 times the overall G-1 percentage increase, exclusive of gas cost revenues. The revenue increase of .9 percent results in a customer charge increase of 2.3 percent, producing a residential customer charge of $4.45. The non-residential customer charge will increase by a similar percentage, from $8.70 to $8.90.

Late Payment Charges

The AG proposed that LG&E's late payment charge be abolished. The AG argued that the charge was not cost-justified and that LG&E had not shown that the charge served as an incentive for prompt payment.

Jefferson et al. proposed a plan to change the way LG&E credits partial payments as a means of reducing the number of late payment charges imposed on customers with past due account balances. At present, LG&E credits partial payments first to the customer's past due balance, then to the current month's bill. Jefferson et al. pointed out that this procedure results in a customer being assessed a late payment charge when it makes a partial payment sufficient to cover its current month's bill because, after the payment is credited to the customer's past due balance, the remainder is not enough to cover the current month's balance. Jefferson et al. argued that this change would encourage customers to make timely payments on their current balances knowing there would be no late payment penalty assessed in a subsequent month when the current month's bill was paid in full.

LG&E argued that the existing procedure serves as an incentive for customers to pay off their past due balances and that the late payment charge functions as an incentive to encourage timely payments. LG&E also argued that if the late payment charge were abolished, the loss of the associated revenues would have to be incorporated into the rates charged all customers.

LG&E's late payment charge has been in its tariffs for many years. The AG performed no analysis on the effectiveness of this charge as an incentive for timely payment of bills. The Commission finds, as it did in LG&E's last rate case,[138] that the late payment charge serves as an incentive and has an important role in LG&E's bill collection strategy.

The arguments of Jefferson et al. to change the way LG&E credits partial payments are persuasive. The Commission finds Jefferson et al.'s plan to be a means of minimizing the instances of recurring late payment charges for customers experiencing payment problems. When a customer can pay the current month's bill plus make a payment toward its past due balance, the customer should not be assessed still another late payment charge.

The Commission is mindful of LG&E's concerns that implementation of Jefferson et al.'s proposal could result in customer laxity toward the payment of past due balances. In considering those concerns, the Commission notes that LG&E retains the ability to terminate service if payment is not eventually made. However, to minimize the need for such actions, the Commission will make the following modification to Jefferson et al.'s proposal to create an incentive for customers to reduce their past due balances: When a customer with a past due balance makes a partial payment sufficient to pay the bill for the current month's usage, plus pay $10.00 or 5 percent of the outstanding past due balance, whichever is greater, LG&E shall credit the

[138] Case No. 10064, Order dated April 20, 1989.

payment to the current month's bill first, then credit the remainder to the past due balance. Crediting the current month's bill first will eliminate the assessment of a late payment penalty on the current month's bill, and requiring some payment toward the past due balance as a prerequisite for such crediting provides the customer an incentive to reduce the past due balance. The Commission finds that such a plan is a reasonable modification to LG&E's current collection procedures and should be approved. LG&E is hereby directed to implement this change in the way it credits partial payments concurrent with the effective date of this Order.

Transportation Service/Standby Service

KIUC recommended that LG&E's tariffs be modified to make standby service optional for all gas transportation customers. KIUC claimed that, under LG&E's existing tariffs, transportation service exclusive of standby service was limited to Rate T transportation customers taking sales service under Rate G-7, Uncommitted Gas Service. KIUC argued that this prerequisite effectively forced transportation customers to take standby service under Rate TS which is available to customers served under sales rates G-1 and G-6.

LG&E contends that Rate T is available to G-1 and G-6 sales customers but that a customer served on Rate T will have no standby or back-up protection for its Rate T volumes other than the G-7 rate for uncommitted gas service.[139] LG&E maintains that

139 T.E., Volume II, November 9, 1990, pages 115-116.

KIUC has misinterpreted the Rate T tariff regarding the precondition of being a G-7 sales customer.

The Commission can understand KIUC's reading and interpretation of the Rate T tariff language which states "available to commercial and industrial customers serviced under Rate G-7. . ." to mean that being a G-7 sales customer is required in order to receive transportation service under Rate T. We also understand LG&E's explanation that the intent of the tariff is to indicate that for customers taking transportation service under Rate T, LG&E will not be obligated to provide standby quantities other than the uncommitted gas available under Rate G-7. Some modification of the tariff language regarding the availability of Rate T is needed to eliminate this misunderstanding. The above-quoted reference to Rate G-7 should be eliminated and a description of the limited protection of uncommitted gas offered under Rate G-7 should be added. LG&E should so modify this tariff when it files its revised tariffs setting forth the rates approved in this proceeding.

Pipeline Demand Charges

KIUC proposed that the pipeline supplier's demand component of LG&E's G-6 rates be reduced. KIUC opined that G-6 customers, being subject to interruption during the winter, have a lower quality of service than G-1 customers, and that this lower quality of service should be reflected in lower rates. We do not agree.

Rate G-6 customers are subject to interruption for only 90 days during the winter season. LG&E's pipeline demand costs are lower due both to its storage capabilities and the interruptibility of rate G-6 customers.

KIUC presented no evidence or analysis to support its argument. G-6 customers receive firm service for all but 90 days of the year. The quality of their service is not significantly different than that of G-1 customers. In addition, LG&E's lower pipeline demand costs are flowed through to all customers, both firm and interruptible, regardless of whether the lower cost results from LG&E's storage capabilities or the interruptibility of its G-6 customers.

Fuel Adjustment Clause

KIUC proposed that LG&E's electric fuel costs be removed from the base energy charges contained in LG&E's tariffs. KIUC argued that fuel costs should be recovered solely through the operation of the fuel clause and should be shown separately from non-fuel costs.

We disagree. The fuel clause regulation, 807 KAR 5:056, requires the establishment of a level of fuel costs in base rates such that, at the time of setting the base rates, the fuel adjustment factor will be equal to zero.

Tariff Changes

The Commission has addressed a number of specific rate design and tariff changes proposed either by LG&E or the intervenors. Several of the changes proposed by LG&E include text additions, deletions, or revisions which were not challenged by any party. The Commission has reviewed all such changes and finds they should be approved. Due to their voluminous nature, these text changes are not included in the Appendix.

OTHER ISSUES

Management Audit

While the Commission is encouraged by the organizational efficiencies and expected savings described by LG&E concerning its work force, the Commission remains concerned that all aspects supporting LG&E's organization structure are not in place. LG&E has indicated that the restructuring or downsizing dealt primarily with management employees.[140] LG&E has apparently not completed its evaluation of human resources needs and systems, but has begun a process of continuous improvement recognizing that the changes will take time to implement properly.[141] LG&E further indicated that this was the first year that organizational development had been seriously included in LG&E's five year plan and that a manpower planning process was currently being designed for implementation in January 1991.[142]

The Commission fully expects LG&E to pursue in a prompt and expeditious manner the organizational and operational efficiencies described during this proceeding. LG&E's efforts in this area will be monitored by the Commission through the normal management audit follow-up process.

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140 T.E., Volume II, November 8, 1990, page 126.

141 Wood Direct Testimony, page 4.

142 T.E., Volume II, November 8, 1990, page 200.

LG&E also discussed the 4KV conversion program stating that the program was scheduled for completion in approximately the year 2004.[143] Because of the savings estimated by LG&E in an internal study, the Commission encourages LG&E to continue its dialogue with the Management Audit Staff regarding the optimal conversion schedule during the management audit follow-up process.

Energy Conservation Programs

Paddlewheel proposed that the Commission establish a task force to design and administer capacity-avoiding conservation programs for LG&E. Paddlewheel suggested that the task force include LG&E Staff, Commission Staff, traditional intervenors, and conservation experts located in LG&E's service territory. Paddlewheel opined that the Commission, or specifically Commission regulations, have impeded the development of conservation programs in Kentucky. Paddlewheel recommended that the Commission provide utilities incentives for conservation by allowing conservation expenditures to be treated as rate base investments on which a utility can earn a return rather than as operating expenses for which it will be reimbursed. Subsequent to the hearing, Paddlewheel filed a motion requesting the Commission enter an Order formally establishing a task force.

LG&E indicated it was interested in expanding its energy conservation programs and would agree with Paddlewheel that rate base treatment of conservation expenditures would serve as an incentive to encourage utilities to design and implement new

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[143] T.E., Volume III, November 9, 1990, page 199.

conservation programs. LG&E also indicated it would like to participate in a collaborative process (task force) to develop new conservation programs.

The Commission endorses the proposal to establish a task force for the purpose of designing and overseeing new conservation programs at LG&E. The Commission is also agreeable to allowing utilities to earn a return on conservation expenditures as an incentive to encourage development of such programs.

The Commission notes that neither at present nor in the past has it had a regulation or policy that acted as a deterrent to utilities making conservation expenditures. In fact, over 9 years ago the Commission stated, "We have in mind an aggressive conservation program, which sees expenditures on conservation not as an unfortunate necessity or misguided effort, but rather as an investment, and as such an alternative to investment in added generating capacity."[144] (emphasis in original) We encourage LG&E and interested intervenors to begin discussion on these matters for the purpose of establishing general goals and establishing a task force, including Commission Staff, to develop new conservation programs for LG&E. However, nothing in Paddlewheel's motion convinces the Commission that there is a present need to order the establishment of such a task force.

[144] Case No. 8177, General Adjustment of Electric Rates of Kentucky Utilities Company, Order dated September 11, 1981.

Cane Run Unit No. 3 ("Cane Run No. 3")

KIUC and Jefferson et al. recommend that LG&E be prohibited from retiring Cane Run No. 3 until an independent evaluation of the unit could be performed to determine its reliability and possible renovation to extend its active service life. Jefferson et al. also proposed that the Commission establish a process requiring a certificate of decommissioning be obtained by a utility prior to retiring a generating unit. After the hearing in this case, Paddlewheel moved to establish a case in order to investigate the status of Cane Run No. 3.

LG&E agreed that it would not retire, or take any measure to retire, Cane Run No. 3 until an independent evaluation was performed on the unit, either by someone chosen by the Commission or selected by agreement of the company and the intervenors.[145] LG&E did, however, have some questions as to the cost and payment for the evaluation and the time frame within which the study might be performed.

The Commission endorses the proposal agreed to by LG&E that an independent party be selected to perform an evaluation of Cane Run No. 3 prior to its retirement from service. LG&E should begin the process of selecting an independent expert to perform the evaluation. In the event that LG&E and the intervenors are unable to agree on an expert, the Commission will facilitate the selection. The cost, as with any outside service, should be borne by LG&E, with rate recovery at some future point. The Commission

[145] T.E., Volume I, November 7, 1990, page 167.

would expect the evaluation to be completed prior to the time of LG&E's initial filing under the integrated resource planning regulation in late 1991. The Commission finds no need to establish a case at this time. Accordingly, Paddlewheel's motion will be denied.

Ohio Valley Electric Corporation ("OVEC") Power Agreement

LG&E is one of 15 owners of OVEC, an electric utility which sells power to the Department of Energy ("DOE") under a contract that expires in October 1992. If the DOE contract is not renewed in 1992, the OVEC power reverts to its owners. LG&E would have rights to 165 MW of OVEC capacity if the contract is not renewed.

KIUC recommended that the Commission implore LG&E to take reasonable steps to enhance the usefulness of the OVEC surplus capacity. KIUC proposed that the Commission hold LG&E financially responsible for the OVEC capacity by refusing to allow additional Trimble County capacity, or other capacity, in rate base so long as LG&E's surplus OVEC entitlement results in sufficient capacity to offset the need for additional Trimble County capacity.

LG&E should take reasonable steps to enhance the usefulness of surplus OVEC capacity and all other available capacity, be it through upgrading its hydro capacity or extending the useful life of Cane Run No. 3. All of these planning issues, and any new conservation programs, can be reviewed under the integrated resource planning regulation. As part of that review, and in future rate cases, the Commission will require that LG&E fully explore OVEC capacity, as well as other capacity alternatives, prior to allowing additional Trimble County capacity in rate base.

Reporting for the Holding Company

In the final Order in Case No. 89-374, the Commission indicated that LG&E should provide certain reports to the Commission concerning the activities of the Holding Company. Since the issuance of that Order, LG&E has become a subsidiary of the Holding Company, as was envisioned in the application in Case No. 89-374. The final Order in Case No. 89-374 did not contain a specific date on which LG&E was to begin providing the listed reports. LG&E should begin filing these reports immediately. Reports due annually should begin with calendar year 1990, and reports due quarterly should begin with the quarter ending December 31, 1990. These reports should be filed with the Commission within 30 days after the end of the reporting period.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds that:

1. The rates in the Appendix, attached hereto and incorporated herein, are the fair, just, and reasonable rates for LG&E to charge for service rendered on and after January 1, 1991.

2. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied.

IT IS THEREFORE ORDERED that:

1. The rates in the Appendix be and they hereby are approved for service rendered by LG&E on and after January 1, 1991.

2. The rates proposed by LG&E are hereby denied.

3. The tariff changes authorized herein are approved for service rendered on and after January 1, 1991.

4. Paddlewheel's motions to establish cases to designate a conservation task force and to investigate the status of Cane Run No. 3 be and they hereby are denied.

5. Within 30 days from the date of this Order, LG&E shall file with the Commission revised tariff sheets setting out the rate and tariff changes approved herein.

6. Annual reports concerning the Holding Company shall begin with calendar year 1990, while quarterly reports concerning the Holding Company shall begin with the quarter ending December 31, 1990. LG&E shall file these reports 30 days after the end of the reporting period.

Done at Frankfort, Kentucky, this 21st day of December, 1990.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 90-158 DATED 12/21/90

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE

RESIDENTIAL RATE
(RATE SCHEDULE R)

RATE:

Customer Charge: $3.29 per meter per month

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	5.905¢ per KWH
Additional kilowatt-hours per month	4.584¢ per KWH

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

First 600 kilowatt-hours per month	6.402¢ per KWH
Additional kilowatt-hours per month	6.555¢ per KWH

WATER HEATING RATE
(RATE SCHEDULE WH)

RATE:

Customer Charge: $0.93 per meter per month.

All kilowatt-hours per month 4.339¢ per KWH

Minimum Bill: The customer charge.

GENERAL SERVICE RATE
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.89 per meter per month for single-phase service
$7.78 per meter per month for three-phase service

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

All kilowatt-hours per month 6.317¢ per KWH

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.102¢ per KWH

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE
RATE SCHEDULE GS

RATE:

Customer Charge: $2.24

For all consumption recorded on the separate meter during the heating season the rate shall be 4.568¢ per kilowatt-hour.

Minimum Bill: The customer charge. This minimum charge is in addition to the regular monthly minimum of Rate GS to which this rider applies.

LARGE COMMERCIAL RATE
(RATE SCHEDULE LC)

RATE:

Customer Charge: $17.09 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: (Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$7.33 per KW per month	$5.68 per KW per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.43 per KW per month	$8.53 per KW per month

Energy Charge:

All kilowatt-hours per month 3.139¢

LARGE COMMERCIAL TIME-OF-DAY RATE

RATE:

Customer Charge: $18.92 per delivery point per month

Demand Charge:

Basic Demand Charge	
Secondary Distribution	$3.71 per KW per month
Primary Distribution	$2.01 per KW per month
Peak Period Demand Charge	
Summer Peak Period	$6.72 per KW per month
Winter Peak Period	$3.57 per KW per month

Energy Charge: 3.139¢ per KWH

INDUSTRIAL POWER
(RATE SCHEDULE LP)

RATE:

Customer Charge: $42.22 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
Winter Rate: (Applicable during 8-monthly billing periods of October through May)			
All kilowatts of billing demand	$8.19 per KW per month	$6.24 per KW per month	$5.03 per KW per month
Summer Rate: (Applicable during 4-monthly billing periods of June through September)			
All kilowatts of billing demand	$10.82 per KW per month	$8.88 per KW per month	$7.66 per KW per month

Energy Charge:

All kilowatt-hours per month 2.716¢ per KWH

INTERRUPTIBLE SERVICE

RATE:

The monthly bill for service under this rider shall be determined in accordance with the provisions of either Rate LC, Rate LC-TOD, Rate LP, or Rate LP-TOD, except there shall be an interruptible demand credit of $3.30 per kilowatt per month.

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

RATE:

Customer Charge: $44.31 per delivery point per month

Demand Charge:	
Basic Demand Charge:	
Secondary Distribution	$5.32 per KW per month
Primary Distribution	$3.34 per KW per month
Transmission Line	$2.13 per KW per month
Peak Period Demand Charge:	
Summer Peak Period	$5.57 per KW per month
Winter Peak Period	$2.96 per KW per month
Energy Charge:	2.708¢ per KWH

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATE:

	Rate Per Month Per Unit	
	Installed Prior to January 1, 1991	Installed After December 31, 1990
Overhead Service		
Mercury Vapor		
100 watt*	$6.92	$ -0-
175 watt	7.83	9.23
250 watt	8.87	10.32
400 watt	10.80	12.37
1000 watt	19.69	22.32
High Pressure Sodium Vapor		
100 watt	$7.69	$7.69
150 watt	9.84	9.84
250 watt	11.62	11.62
400 watt	12.27	12.27
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	$12.06	$12.81
175 Watt - Top Mounted	12.83	13.81

High Pressure Sodium Vapor

100 Watt - Top Mounted	$14.19	$14.19
150 Watt	19.33	19.33
250 Watt	22.17	22.17
400 Watt	24.40	24.40

* Restricted to those units in service on 5-31-79.

Special Terms and Conditions:

Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. The customer to pay an additional charge of $1.64 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

PUBLIC STREET LIGHTING SERVICE
(RATE SCHEDULE PSL)

RATE:

	Rate Per Month Per Unit	
	Installed Prior to January 1, 1991	Installed After December 31, 1990
Type of Unit		
Overhead Service		
Mercury Vapor		
100 Watt (open bottom fixture)	$6.22	$ -0-
175 Watt	7.28	9.05
250 Watt	8.28	10.15
400 Watt	9.90	12.20
400 Watt (underground pole)	14.31	-0-
1000 Watt	18.39	22.07

High Pressure Sodium Vapor		
150 Watt	8.90	8.90
250 Watt	10.66	10.66
400 Watt	11.10	11.10
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	10.16	12.55
175 Watt - Top Mounted	11.12	13.63
175 Watt	15.09	21.47
250 Watt	16.12	22.57
400 Watt	18.96	24.62
400 Watt on State of KY Pole	11.21	-0-
High Pressure Sodium Vapor		
100 Watt - Top Mounted	11.17	11.17
150 Watt	19.32	19.32
250 Watt	20.50	20.50
250 Watt on State of KY Pole	10.48	-0-
400 Watt	21.95	21.95
Incandescent		
1500 Lumen	8.29	-0-
6000 Lumen	10.91	-0-

STREET LIGHTING ENERGY RATE
(RATE SCHEDULE SLE)

RATE: $3.972¢ per kilowatt hour

TRAFFIC LIGHTING ENERGY RATE
(RATE SCHEDULE TLE)

RATE:

Customer Charge: $2.45 per meter per month

All kilowatt-hour per month 4.992¢ per KWH

Minimum Bill The customer charge.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
CARBON GRAPHITE SPECIAL CONTRACT

Demand Charge

Primary Power (28,500 KW)	$11.82 per KW per month
Secondary Power (Excess KW)	$5.91 per KW per month
Demand Credit for Primary Interruptible Power (24,500 KW)	$3.30 per KW per month
Energy Charge All KWH	1.946¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

Demand Charge

$11.14 per KW of billing demand per month

Energy Charge

2.012¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
FORT KNOX SPECIAL CONTRACT

Demand Charge

Winter Rate:
(Applicable during 8 monthly billing periods of October through May)

All KW of Billing Demand	$6.32 per KW per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All KW of Billing Demand	$8.52 per KW per month
Energy Charge: All KWH per month	2.605¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

$7.62 per KW of billing demand per month

Energy Charge

2.138¢ per KWH

GAS SERVICE

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through Case No. 10064-J.

GENERAL GAS RATE
G-1

RATE:

Customer Charge:

$4.45 per delivery point per month for residential service
$8.90 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	11.075¢
Gas Supply Cost Component	27.323¢
Total Charge Per 100 Cubic Feet	38.398¢

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

RATE:

The rate for "Summer Air Conditioning Consumption," as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:

Distribution Cost Component	6.075¢
Gas Supply Cost Component	27.323¢
Total Charge Per 100 Cubic Feet	33.398¢

GAS TRANSPORTATION SERVICE/STANDBY
RATE TS

RATE:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

	G-1	G-6
Distribution Charge Per Mcf	$1.1075	$0.5300
Pipeline Supplier's Demand Component	.2032	.2032
Total	$1.3107	$0.7332

LG&E Case No. 90-158 Rebuttal Testimony – Randall J. Walker
Responding Witness – William Steven Seelye

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY)	CASE NO. 90-158

REBUTTAL TESTIMONY OF
RANDALL J. WALKER

Q. Please state your name.
A. Randall J. Walker

Q. Are you the same Randall J. Walker who earlier filed direct testimony in this case?
A. Yes.

Q. Have you reviewed the testimony and Schedule 20 of Thomas C. De Ward wherein he proposed to reduce electric fuel expenses in the test period by $1,737,240 to match the level of adjusted fuel related revenues?
A. Yes, I have.

Q. Do you agree or disagree with his conclusion that such a reduction is proper in this case?
A. I disagree. Mr. De Ward's proposed reduction appears to be based, at least in part, upon his impression that the fuel clause is a fully recovering fuel clause (See De

Ward response to Question #47a of LG&E's request for information). In order to get the impression that such an adjustment is proper, one must either assume that the fuel clause mechanism in effect during the test period accurately tracked fuel costs on a timely basis, or that the revised mechanism that became effective after the test period (July 1, 1990) and which includes an over- and under-recovery provision will do so. It is obvious that the previous mechanism did not accomplish this, as confirmed by the under-recovery during the test period. Therefore, I can only assume that Mr. De Ward has chosen to ignore the test period results and is basing his recommendation on the "impression" that the inclusion of an over- and under-recovery mechanism will somehow eliminate future mismatches.

Q. Wasn't there a data request by the Commission in this proceeding that addressed this subject?

A. Yes. In its Order dated August 29, 1990, Question No. 22, the Commission asked for an explanation of the differences between fuel costs and fuel recoveries and, in view of the newly incorporated over- and under-recovery mechanism, the reason any over- or under-recoveries should be included in rate case revenue requirements.

Q. What was LG&E's response to that data request?

A. We pointed out that a matching of fuel costs and recoveries is impossible under the present methodology, that the over- and under-recovery mechanism was not placed into effect until after the end of the test period and that the over-and under-recovery mechanism will not provide for a full reconciliation of fuel costs and FAC revenues.

Q. What prevents the fuel clause mechanism from accurately tracking fuel costs?

A. The recovery of fuel clause revenues is not synchronized with the incurrence of LG&E's fuel expenses. In other words, a timing difference exists between when the costs are incurred by the Company and the billing of those costs. For example, fuel clause billings made in November 1990 are based on unit fuel costs from September 1990. Likewise, fuel costs incurred in November 1990 will not be billed to the customers until January 1991. In any given twelve month test period, the fuel clause revenues are based on two months of fuel expenses that occurred prior to the beginning of the test period and 10 months of fuel expenses within the period. Fuel clause billings which recover the last two months of fuel expenses in the test period will not occur until after the end of the test period. This two month lag precludes a matching of expenses and revenues in any twelve month period.

The Commission has always recognized that the fuel clause mechanism was not designed to match revenues with expenses over a particular period of time, but was designed to track a variable cost without a general rate proceeding. In its determination of revenue requirements in past rate proceedings, no adjustments were made by the Commission to match fuel expenses with FAC revenues. Differences between fuel expenses and fuel related revenues must remain in the 12-month test period, otherwise the Company has no opportunity to recover its costs.

Q. *Why doesn't the new over- and under-recovery mechanism take care of this problem?*

A. As pointed out in our comments filed with the Commission on January 29, 1990, in Administrative Case No. 309, the over- and under-recovery mechanism will only slightly improve the match between fuel clause revenues and fuel costs, but will <u>not</u> provide for a full reconciliation of costs. That conclusion were based on several years of historical data wherein recoveries under the then effective mechanism were compared with computed recoveries under the proposed mechanism. Attached hereto as Walker Rebuttal Exhibit 1, are those computations.

As shown on page 3, approximately $1,229 million of fuel costs were incurred by LG&E during 1989 and the 10 prior years, beginning in January 1979, and $1,224 million of those costs were recovered under the FAC mechanism. By incorporating the over- and under-recovery provision into the mechanism, the recoveries would have been $1,225 million during the same period (Exhibit 1, page 6)--- a better match, but certainly not a full recovery.

The new over- and under-recovery mechanism merely gives effect to differences between the Kwh's used in determining the FAC rate and the Kwh's to which the FAC rate is actually applied, two months later. There is no provision to reconcile expenses and recoveries month by month as they actually occur. In addition, the Kwh differences are multiplied by the FAC rate, not the total fuel cost per Kwh, when determining the amount of monthly over- and under-recoveries to be tracked through future billings. The mechanism cannot be expected to provide for a full reconciliation of costs and revenues.

While the fuel clause mechanism applicable to LG&E and all other regulated utilities within the state "generally" tracks fuel costs, it was not designed to precisely match fuel expenses and fuel recoveries. With both fuel prices and sales volumes likely to increase over the long-term, utilities will almost always be in the position of under-recovering their fuel costs, even with the new over- and under-recovery mechanism.

Q. Since the FAC and the Gas Supply Clause both have over- and under-recovery mechanisms, why doesn't the new FAC mechanism accomplish the matching achieved by the Gas Supply Clause?

A. First, the recovery of gas supply costs through the GSC is synchronized with the incurrence of those costs. The quarterly recovery charge is determined by calculating the supply costs for a 3-month based on known purchased gas and storage withdrawal costs and dividing such costs by the expected customer deliveries in that same 3-month period. The FAC, as mentioned earlier, does not bill for incurred fuel costs until two months after the fact. Second, GSC over- and under-recoveries which are tracked through future billings result from a measurement of actual quarterly supply costs against actual quarterly GSC revenues within the same time period. FAC over- and under-recoveries, on the other hand, are based on differences between the Kwh's used to determine the unit charge and the Kwh's billed at such charge two months later. Third, the amount of GSC over- and under-recoveries are determined on the basis of the difference between <u>total</u> gas supply costs incurred during a specific 3-month period and the <u>total</u> GSC revenues recovered during the same period. As indicated earlier, the over-and under-recovery mechanism in the FAC only deals with the credit below or charge above a predetermined base.

Q. What would the effect be on LG&E if the Commission were to accept Mr. De Ward's proposal and reduce fuel expenses by $1.74 million?

A. LG&E is entitled to recover all of its legitimate operating costs, including fuel expenses not recovered through the FAC. Neither the fuel clause mechanism in effect during the test period nor the revised July 1 mechanism is designed to provide LG&E with full recovery of fuel costs in the twelve months contained in the test period or any other specific twelve month period. Therefore, the Commission must, as it has done in past cases, recognize the inherent mismatch in fuel costs and fuel recoveries under the FAC mechanism. Otherwise, LG&E would be placed in a position of not having an opportunity to recover its costs.

Q. Does this complete your rebuttal testimony?

A. Yes.

WALKER REBUTTAL EXHIBIT I

FUEL COST AND FAC REVENUES
METHODOLOGY PRECEDING OVER- AND UNDER- RECOVERY MECHANISM

		FUEL COST	FORCED OUTAGE	NET FUEL COST	DETERMINATION KWH	COST / KWH	LESS: BASE / KWH	FAC CHG.	APPLICABLE KWH	UNIT CHARGE	FAC REVENUE	BASE REVENUE	TOTAL RECOVERY
NOV	1978	$6,159,965	-$6,954	$6,153,011	567,967,103	$0.01083	$0.01235	-$0.00152	553,346,116				
DEC		6,855,344	-33,733	6,821,611	604,223,872	0.01129	0.01235	-0.00106	587,109,478				
JAN	1979	$8,104,184	-$86,192	$8,017,992	699,462,062	$0.01146	$0.01235	-$0.00089	674,244,071	-$0.00152	-$1,024,851	$8,326,914	$7,302,063
FEB		6,584,870	-30,276	6,554,594	609,781,364	0.01075	0.01235	-0.00160	661,059,262	-0.00106	-700,723	8,164,082	7,463,359
MAR		6,570,053	-77,748	6,492,305	590,033,711	0.01100	0.01235	-0.00135	602,871,360	-0.00089	-536,556	7,445,461	6,908,906
APR		6,108,553	-24,543	6,084,010	543,064,646	0.01120	0.01235	-0.00115	563,320,543	-0.00160	-901,313	6,957,009	6,055,696
MAY		6,374,323	-16,255	6,358,068	595,866,484	0.01067	0.01235	-0.00168	578,987,270	-0.00135	-781,633	7,150,493	6,368,860
JUN		7,581,185	-21,172	7,560,013	706,841,977	0.01070	0.01235	-0.00165	642,873,612	-0.00115	-739,305	7,939,489	7,200,184
JUL		7,929,725	-3,325	7,926,400	735,273,018	0.01078	0.01235	-0.00157	711,406,710	-0.00168	-1,195,163	8,785,873	7,590,710
AUG		8,858,455	-79,688	8,778,767	782,323,460	0.01122	0.01235	-0.00113	754,558,105	-0.00165	-1,245,021	9,318,793	8,073,772
SEP		7,098,691	-16,499	7,082,192	638,375,516	0.01109	0.01235	-0.00126	718,373,731	-0.00157	-1,127,847	8,871,916	7,744,069
OCT		6,714,213	-16,024	6,698,189	584,268,170	0.01146	0.01235	-0.00089	591,324,466	-0.00113	-668,197	7,302,857	6,634,661
NOV		6,611,224	-14,566	6,596,658	575,410,409	0.01146	0.01235	-0.00089	558,650,753	-0.00126	-703,900	6,899,337	6,195,437
DEC		6,968,466	-35,293	6,933,173	601,002,106	0.01154	0.01235	-0.00081	589,258,752	-0.00089	-524,440	7,277,346	6,752,905
JAN	1980	$7,395,276	-$43,059	$7,352,217	640,738,485	$0.01147	$0.01235	-$0.00088	631,527,301	-$0.00089	-$562,059	$7,799,362	$7,237,303
FEB		7,219,921	-20,353	7,199,568	613,607,185	0.01173	0.01235	-0.00062	633,103,980	-0.00081	-512,814	7,818,834	7,306,020
MAR		7,487,189	-10,066	7,477,123	616,174,650	0.01213	0.01235	-0.00022	611,687,505	-0.00088	-538,285	7,554,341	7,016,056
APR		6,588,682	-14,284	6,574,398	536,303,040	0.01226	0.01235	-0.00009	565,066,175	-0.00062	-350,341	6,978,567	6,628,226
MAY		7,125,162	-91,144	7,034,018	567,549,129	0.01239	0.01235	0.00004	530,124,546	-0.00022	-116,627	6,547,038	6,430,411
JUN		8,105,545	-165,580	7,939,965	659,979,758	0.01203	0.01235	-0.00032	618,482,141	-0.00009	-55,663	7,638,254	7,582,591
JUL		10,841,883	-31,041	10,810,842	859,338,586	0.01258	0.01235	0.00023	760,680,715	0.00004	30,427	9,394,407	9,424,834
AUG		11,119,823	-69,354	11,050,469	855,917,986	0.01291	0.01235	0.00056	863,556,380	-0.00032	-276,338	10,664,921	10,388,583
SEP		8,805,940	-14,460	8,791,480	683,437,217	0.01286	0.01235	0.00051	795,941,617	0.00023	183,067	9,829,879	10,012,946
OCT		7,541,489	-2,344	7,539,145	584,548,165	0.01290	0.01235	0.00055	624,664,120	0.00056	349,812	7,714,602	8,064,414
NOV		7,059,946	-1,125	7,058,821	574,554,630	0.01229	0.01235	-0.00006	554,496,140	0.00051	282,793	6,848,027	7,130,820
DEC		7,684,084	-3,207	7,680,877	619,041,050	0.01241	0.01235	0.00006	601,091,254	0.00055	330,600	7,423,477	7,754,077
JAN	1981	$8,674,025	-12,141	$8,661,884	670,698,632	$0.01291	$0.01235	$0.00056	675,380,364	-$0.00006	-$40,523	$8,340,947	$8,300,425
FEB		7,563,169	-6,009	7,557,160	577,233,600	0.01309	0.01235	0.00074	624,815,879	0.00006	37,489	7,716,476	7,753,965
MAR		7,734,091	-5,875	7,728,216	601,770,235	0.01284	0.01235	0.00049	583,071,810	0.00056	326,520	7,200,937	7,527,457
APR		7,434,266	-8,976	7,425,290	544,279,497	0.01364	0.01235	0.00129	545,413,351	0.00074	403,606	6,735,855	7,139,461
MAY		7,771,548	-2,749	7,768,799	570,023,442	0.01363	0.01235	0.00128	542,219,520	0.00049	265,688	6,696,411	6,962,099
JUN		10,774,549	-123,503	10,651,046	734,501,584	0.01450	0.01235	0.00215	665,854,376	0.00129	858,952	8,223,302	9,082,254
JUL		11,091,617	-79,381	11,012,236	828,151,537	0.01330	0.01235	0.00095	792,629,426	0.00128	1,014,566	9,788,973	10,803,539
AUG		10,642,188	-24,509	10,617,679	767,844,458	0.01383	0.01235	0.00148	769,781,912	0.00215	1,655,031	9,506,807	11,161,838
SEP		8,584,858	-73,252	8,511,606	623,608,260	0.01365	0.01235	0.00130	705,656,033	0.00095	670,373	8,714,852	9,385,225
OCT		7,756,852	-18,909	7,737,943	571,878,575	0.01353	0.01235	0.00118	583,523,750	0.00148	863,615	7,206,518	8,070,133
NOV		7,292,818	-19,762	7,273,056	552,745,178	0.01316	0.01235	0.00081	546,237,463	0.00130	710,109	6,746,033	7,456,141
DEC		8,787,129	-27,217	8,759,912	604,507,328	0.01449	0.01235	0.00214	565,491,105	0.00118	667,280	6,983,815	7,651,095
JAN	1982	$9,852,129	-$28,399	$9,823,730	670,401,206	$0.01465	$0.01235	$0.00230	651,270,182	$0.00081	$527,529	$8,043,187	$8,570,716
FEB		8,710,670	-36,228	8,674,442	574,042,118	0.01511	0.01235	0.00276	643,701,267	0.00214	1,377,521	7,949,711	9,327,231
MAR		8,771,457	-84,358	8,687,099	575,493,352	0.01510	0.01235	0.00275	590,288,362	0.00230	1,357,663	7,290,061	8,647,725
APR		7,823,720	-61,128	7,762,592	540,119,589	0.01437	0.01235	0.00202	553,177,382	0.00276	1,526,770	6,831,741	8,358,510
MAY		9,112,824	-78,272	9,034,552	621,406,576	0.01454	0.01235	0.00219	563,691,124	0.00275	1,550,151	6,961,585	8,511,736
JUN		9,832,025	-125,598	9,706,427	636,686,332	0.01525	0.01235	0.00290	649,213,674	0.00202	1,311,412	8,017,789	9,329,200
JUL		12,240,858	-132,316	12,108,542	784,620,291	0.01543	0.01235	0.00308	687,371,959	0.00219	1,505,345	8,489,044	9,994,388
AUG		11,012,894	-15,281	10,997,613	696,272,474	0.01579	0.01235	0.00344	740,827,011	0.00290	2,148,398	9,149,214	11,297,612
SEP		9,351,210	-62,640	9,288,570	585,773,913	0.01586	0.01235	0.00351	636,430,474	0.00308	1,960,206	7,859,916	9,820,122
OCT		8,667,327	-30,094	8,637,233	571,667,760	0.01511	0.01235	0.00276	567,330,165	0.00344	1,951,616	7,006,528	8,958,143
NOV		8,203,027	-185,690	8,017,337	540,057,795	0.01485	0.01235	0.00250	535,276,154	0.00351	1,878,819	6,610,661	8,489,480
DEC		8,768,034	-74,597	8,693,437	567,481,904	0.01532	0.01235	0.00297	552,008,451	0.00276	1,523,543	6,817,304	8,340,848

		FUEL COST	FORCED OUTAGE	NET FUEL COST	DETERMINATION KWH	COST / KWH	LESS: BASE / KWH	FAC CHG.	APPLICABLE KWH	UNIT CHARGE	FAC REVENUE	BASE REVENUE	TOTAL RECOVERY
JAN	1983	$9,085,269	-$70,357	$9,014,912	629,424,898	$0.01432	$0.01235	$0.00197	601,909,166	$0.00250	$1,504,773	$7,433,578	$8,938,351
FEB		7,933,385	-13,858	7,919,527	562,468,528	0.01408	0.01235	0.00173	611,186,900	0.00297	1,815,225	7,548,158	9,363,383
MAR		8,430,544	-20,055	8,410,489	592,690,735	0.01419	0.01235	0.00184	592,674,228	0.00197	1,167,568	7,319,527	8,487,095
APR		7,892,339	-2,232	7,890,107	542,273,115	0.01455	0.01235	0.00220	558,972,641	0.00173	967,023	6,903,312	7,870,335
MAY		8,394,405	-106,013	8,288,392	553,555,239	0.01497	0.01235	0.00262	540,569,702	0.00184	994,648	6,676,036	7,670,684
JUN		9,883,251	-20,372	9,862,879	683,654,395	0.01443	0.01373	0.00070	593,679,563	0.00220	1,306,095	7,331,943	8,638,038
JUL		13,239,796	-45,576	13,194,220	858,721,589	0.01536	0.01511	0.00025	768,076,250	0.00262	2,012,360	11,605,632	13,617,992
AUG		13,476,576	-14,400	13,462,176	878,251,187	0.01533	0.01511	0.00022	898,122,836	0.00070	628,686	13,570,636	14,199,322
SEP		9,765,816	-20,971	9,744,845	668,142,948	0.01458	0.01511	-0.00053	808,393,780	0.00025	202,098	12,214,830	12,416,928
OCT		8,445,995	-10,700	8,435,295	573,881,905	0.01470	0.01511	-0.00041	609,543,864	0.00022	134,100	9,210,208	9,344,307
NOV		8,059,072	-32,316	8,026,756	573,295,336	0.01400	0.01511	-0.00111	556,221,316	-0.00053	-294,797	8,404,504	8,109,707
DEC		10,869,504	-13,186	10,856,318	683,451,324	0.01588	0.01511	0.00077	608,624,005	-0.00041	-249,536	9,196,309	8,946,773
JAN	1984	$10,304,206	-112,789	$10,191,417	689,315,665	$0.01478	0.01511	-$0.00033	694,580,909	-$0.00111	-$770,985	$10,495,118	$9,724,133
FEB		8,336,154	-63,600	8,272,554	583,001,523	0.01419	0.01511	-0.00092	659,869,989	0.00077	508,100	9,970,636	10,478,735
MAR		9,276,660	-8,358	9,268,302	640,377,517	0.01447	0.01511	-0.00064	623,174,677	-0.00033	-205,648	9,416,169	9,210,522
APR		8,386,855	-11,214	8,375,641	563,719,657	0.01486	0.01511	-0.00025	589,028,289	-0.00092	-541,906	8,900,217	8,358,311
MAY		8,783,262	-22,357	8,760,905	593,872,877	0.01475	0.01511	-0.00036	570,133,365	-0.00064	-364,885	8,614,715	8,249,830
JUN		12,315,725	-80,622	12,235,103	788,729,839	0.01551	0.01511	0.00040	691,629,068	-0.00025	-172,907	10,450,515	10,277,608
JUL		11,668,231	-35,972	11,632,259	781,144,888	0.01489	0.01511	-0.00022	782,561,680	-0.00036	-281,722	11,824,507	11,542,785
AUG		12,109,123	-33,937	12,075,186	807,426,157	0.01496	0.01511	-0.00015	784,846,550	0.00040	313,939	11,859,031	12,172,970
SEP		9,103,280	-18,555	9,084,725	634,741,975	0.01431	0.01511	-0.00080	714,654,099	-0.00022	-157,224	10,798,423	10,641,200
OCT		8,616,719	-18,597	8,598,122	604,272,913	0.01423	0.01511	-0.00088	601,052,111	-0.00015	-90,158	9,081,897	8,991,740
NOV		8,356,179	0	8,356,179	595,349,867	0.01404	0.01511	-0.00107	587,107,170	-0.00080	-469,686	8,871,189	8,401,504
DEC		9,905,679	-98,029	9,807,650	608,478,872	0.01612	0.01511	0.00101	627,369,580	-0.00088	-552,085	9,479,554	8,927,469
JAN	1985	$11,418,068	-$17,098	$11,400,970	735,176,841	$0.01551	$0.01511	$0.00040	652,480,583	-$0.00107	-$698,154	$9,858,982	$9,160,827
FEB		9,385,792	0	9,385,792	625,158,933	0.01501	0.01511	-0.00010	705,367,062	0.00101	712,421	10,658,096	11,370,517
MAR		9,546,765	0	9,546,765	608,221,824	0.01570	0.01511	0.00059	617,315,172	0.00040	246,926	9,327,632	9,574,558
APR		8,502,352	-20,329	8,482,023	589,205,804	0.01440	0.01511	-0.00071	590,963,157	-0.00010	-59,096	8,929,453	8,870,357
MAY		8,934,789	-12,978	8,921,811	631,040,365	0.01414	0.01511	-0.00097	594,513,265	0.00059	350,763	8,983,095	9,333,858
JUN		10,207,368	-18,067	10,189,301	704,089,152	0.01447	0.01511	-0.00064	667,898,900	-0.00071	-474,208	10,091,952	9,617,744
JUL		12,108,366	-13,574	12,094,792	815,574,885	0.01483	0.01511	-0.00028	751,110,552	-0.00097	-728,577	11,349,280	10,620,703
AUG		11,418,580	-10,000	11,408,580	791,392,833	0.01442	0.01511	-0.00069	825,054,093	-0.00064	-528,035	12,466,567	11,938,533
SEP		10,247,301	-10,719	10,236,582	695,648,290	0.01472	0.01511	-0.00039	764,568,833	-0.00028	-214,079	11,552,635	11,338,556
OCT		8,879,052	-41,973	8,837,079	625,872,361	0.01412	0.01511	-0.00099	630,796,491	-0.00069	-435,250	9,531,335	9,096,085
NOV		8,645,071	-12,275	8,632,796	591,119,184	0.01460	0.01511	-0.00051	588,786,767	-0.00039	-229,627	8,896,568	8,666,941
DEC		10,468,421	-30,457	10,437,964	691,339,432	0.01510	0.01511	-0.00001	636,426,256	-0.00099	-630,062	9,616,401	8,986,339
JAN	1986	$9,796,383	-$15,486	$9,780,897	690,789,400	$0.01416	$0.01511	-$0.00095	676,987,589	-$0.00051	-$345,264	$10,229,282	$9,884,019
FEB		9,053,647	-28,498	9,025,149	605,129,377	0.01491	0.01511	-0.00020	655,537,806	-0.00001	-6,555	9,905,176	9,898,621
MAR		9,083,932	-28,426	9,055,506	624,884,143	0.01449	0.01511	-0.00062	657,930,140	-0.00095	-625,034	9,941,324	9,316,291
APR		8,306,232	-22,927	8,283,305	597,198,389	0.01387	0.01511	-0.00124	599,816,610	-0.00020	-119,963	9,063,229	8,943,266
MAY		9,461,763	10,921	9,472,684	660,437,640	0.01434	0.01511	-0.00077	622,236,720	-0.00062	-385,787	9,401,997	9,016,210
JUN		11,783,719	-9,737	11,773,982	799,497,070	0.01473	0.01511	-0.00038	722,633,211	-0.00124	-896,065	10,918,988	10,022,923
JUL		13,661,286	-38,913	13,622,373	934,887,696	0.01457	0.01511	-0.00054	873,666,713	-0.00077	-672,723	13,201,104	12,528,381
AUG		11,201,133	-18,246	11,182,887	780,167,402	0.01433	0.01511	-0.00078	829,836,956	-0.00038	-315,338	12,538,836	12,223,498
SEP		10,616,589	-8,236	10,608,353	727,068,311	0.01459	0.01511	-0.00052	739,997,393	-0.00054	-399,599	11,181,361	10,781,762
OCT		9,010,883	6,518	9,017,401	646,039,119	0.01396	0.01511	-0.00115	711,561,412	-0.00078	-555,018	10,751,693	10,196,675
NOV		8,902,681	-14,992	8,887,689	615,233,490	0.01445	0.01511	-0.00066	608,639,492	-0.00052	-316,493	9,196,543	8,880,050
DEC		9,529,790	-23,689	9,506,101	679,041,254	0.01400	0.01511	-0.00111	646,819,879	-0.00115	-743,843	9,773,448	9,029,606

		FUEL COST	FORCED OUTAGE	NET FUEL COST	DETERMINATION KWH	COST / KWH	LESS: BASE / KWH	FAC CHG.	APPLICABLE KWH	UNIT CHARGE	FAC REVENUE	BASE REVENUE	TOTAL RECOVERY
JAN	1987	$9,789,579	-15,365	$9,774,214	708,458,076	$0.01380	$0.01511	-$0.00131	666,835,301	-$0.00066	-$440,111	$10,075,881	$9,635,770
FEB		8,399,216	-11,780	8,387,436	612,525,766	0.01369	0.01511	-0.00142	681,914,489	-0.00111	-756,925	10,303,728	9,546,803
MAR		8,865,203	-69,672	8,795,531	636,818,570	0.01381	0.01511	-0.00130	661,072,572	-0.00131	-866,005	9,988,807	9,122,801
APR		8,724,073	-11,433	8,712,640	600,744,664	0.01450	0.01511	-0.00061	604,105,994	-0.00142	-857,831	9,128,042	8,270,211
MAY		10,435,507	-1,017	10,434,490	746,621,109	0.01398	0.01511	-0.00113	665,735,060	-0.00130	-865,456	10,059,257	9,193,801
JUN		11,618,765	-3,357	11,615,408	838,433,466	0.01385	0.01511	-0.00126	811,423,397	-0.00061	-494,968	12,260,608	11,765,639
JUL		12,856,610	-8,713	12,847,897	910,516,624	0.01411	0.01511	-0.00100	863,965,915	-0.00113	-976,281	13,054,525	12,078,243
AUG		13,215,484	-6,375	13,209,109	920,769,307	0.01435	0.01511	-0.00076	924,095,119	-0.00126	-1,164,360	13,963,077	12,798,717
SEP		10,096,793	-8,896	10,087,897	723,512,393	0.01394	0.01511	-0.00117	800,640,695	-0.00100	-800,641	12,097,681	11,297,040
OCT		8,786,049	-481	8,785,568	637,735,904	0.01378	0.01511	-0.00133	662,212,231	-0.00076	-503,281	10,006,027	9,502,746
NOV		8,613,694	-2,961	8,610,733	623,019,208	0.01382	0.01511	-0.00129	624,676,588	-0.00117	-730,872	9,438,863	8,707,992
DEC		9,918,628	-12,745	9,905,883	688,550,872	0.01439	0.01511	-0.00072	647,667,744	-0.00133	-861,398	9,786,260	8,924,862
JAN	1988	$10,551,025	-$9,979	$10,541,046	749,097,296	$0.01407	$0.01511	-$0.00104	722,290,090	-$0.00129	-$931,754	$10,913,803	$9,982,049
FEB		9,625,541	8,335	9,633,876	684,902,221	0.01407	0.01511	-0.00104	717,414,614	-0.00072	-516,539	10,840,135	10,323,596
MAR		9,435,164	-65,840	9,369,324	678,160,447	0.01382	0.01511	-0.00129	697,816,187	-0.00104	-725,729	10,544,003	9,818,274
APR		8,341,574	-6,836	8,334,738	607,596,805	0.01372	0.01511	-0.00139	642,207,596	-0.00104	-667,896	9,703,757	9,035,861
MAY		9,541,364	-5,843	9,535,521	687,444,652	0.01387	0.01511	-0.00124	630,382,017	-0.00129	-813,193	9,525,072	8,711,879
JUN		11,843,685	-7,081	11,836,604	853,325,744	0.01387	0.01511	-0.00124	772,140,208	-0.00139	-1,073,275	11,667,039	10,593,764
JUL		13,391,680	-46,076	13,345,604	949,394,150	0.01406	0.01511	-0.00105	926,246,663	-0.00124	-1,148,546	13,995,587	12,847,041
AUG		14,210,726	-65,164	14,145,562	994,497,365	0.01422	0.01511	-0.00089	970,418,545	-0.00124	-1,203,319	14,663,024	13,459,705
SEP		10,140,563	-44,950	10,095,613	723,512,158	0.01395	0.01511	-0.00116	821,317,309	-0.00105	-862,383	12,410,105	11,547,721
OCT		8,940,432	-32,880	8,907,552	658,408,792	0.01353	0.01511	-0.00158	671,099,346	-0.00089	-597,278	10,140,311	9,543,033
NOV		8,828,524	-8,591	8,819,933	656,048,138	0.01344	0.01511	-0.00167	657,446,975	-0.00116	-762,638	9,934,024	9,171,385
DEC		10,504,421	-33,714	10,470,707	715,283,670	0.01464	0.01511	-0.00047	700,471,813	-0.00158	-1,106,745	10,584,129	9,477,384
JAN	1989	$10,001,635	-9,313	$9,992,322	715,531,116	$0.01396	$0.01511	-$0.00115	721,095,552	-$0.00167	-$1,204,230	$10,895,754	$9,691,524
FEB		9,480,645	-9,082	9,471,563	694,095,199	0.01365	0.01511	-0.00146	708,490,740	-0.00047	-332,991	10,705,295	10,372,304
MAR		8,906,650	-11,768	8,894,882	693,513,240	0.01283	0.01511	-0.00228	719,342,271	-0.00115	-827,244	10,869,262	10,042,018
APR		8,204,893	-11,134	8,193,759	663,460,083	0.01235	0.01511	-0.00276	662,057,594	-0.00146	-966,604	10,003,690	9,037,086
MAY		8,641,611	-11,166	8,630,445	699,443,844	0.01234	0.01511	-0.00277	651,059,508	-0.00228	-1,484,416	9,837,509	8,353,093
JUN		10,275,856	-7,451	10,268,405	830,709,032	0.01236	0.01467	-0.00231	798,053,688	-0.00276	-2,202,628	12,058,591	9,855,963
JUL		11,598,876	-8,586	11,590,290	941,420,123	0.01231	0.01422	-0.00191	900,627,978	-0.00277	-2,494,739	13,045,113	10,550,374
AUG		11,232,655	-1,854	11,230,801	930,582,203	0.01207	0.01422	-0.00215	884,090,433	-0.00231	-2,042,249	12,572,547	10,530,298
SEP		9,488,940	-2,190	9,486,750	777,774,560	0.01220	0.01422	-0.00202	872,833,851	-0.00191	-1,667,113	12,411,697	10,744,585
OCT		8,317,543	-1,599	8,315,944	691,788,820	0.01202	0.01422	-0.00220	686,601,233	-0.00215	-1,476,193	9,763,470	8,287,277
NOV		8,134,220	-3,050	8,131,170	679,330,891	0.01197	0.01422	-0.00225	667,623,594	-0.00202	-1,348,600	9,493,608	8,145,008
DEC		10,134,987	-1,608	10,133,379	806,692,333	0.01256	0.01422	-0.00166	738,301,470	-0.00220	-1,624,263	10,498,647	8,874,384
TOTALS*				$1,228,825,022									$1,223,922,518

*Total Jan. 1979 to Dec. 1989

FUEL COST AND FAC REVENUES
APPLYING OVER- AND UNDER- RECOVERY MECHANISM

		FUEL COST	LESS: FORCED OUTAGE	COMMISSION PROPOSAL LESS OVER/ PLUS UNDER RECOVERY	FUEL INCLUDING OVER/UNDER RECOVERY	DETERMINATION KWH	COST / KWH	FAC CHG.	APPLICABLE KWH	UNIT CHARGE	FAC REVENUE	BASE REVENUE	TOTAL RECOVERY
NOV	1978	$6,159,965	-$6,954		$6,153,011	567,967,103	$0.01083	-$0.00152	553,346,116				
DEC		6,855,344	-33,733		6,821,611	604,223,872	0.01129	-0.00106	587,109,478				
JAN	1979	$8,104,184	-$86,192	$161,541	$8,179,533	699,462,062	$0.01169	-$0.00066	674,244,071	-$0.00152	-$1,024,851	$8,326,914	$7,302,063
FEB		6,584,870	-30,276	60,246	6,614,840	609,781,364	0.01085	-0.00150	661,059,262	-0.00106	-700,723	8,164,082	7,463,359
MAR		6,570,053	-77,748	-63,750	6,428,555	590,033,711	0.01090	-0.00145	602,871,360	-0.00066	-397,895	7,445,461	7,047,566
APR		6,108,553	-24,543	-69,691	6,014,319	543,064,646	0.01107	-0.00128	563,320,543	-0.00150	-844,981	6,957,009	6,112,028
MAY		6,374,323	-16,255	-16,017	6,342,051	595,866,484	0.01064	-0.00171	578,987,270	-0.00145	-839,532	7,150,493	6,310,961
JUN		7,581,185	-21,172	127,755	7,687,768	706,841,977	0.01088	-0.00147	642,873,612	-0.00128	-822,878	7,939,489	7,116,611
JUL		7,929,725	-3,325	197,574	8,123,974	735,273,018	0.01105	-0.00130	711,406,710	-0.00171	-1,216,505	8,785,873	7,569,367
AUG		8,858,455	-79,688	70,143	8,848,910	782,323,460	0.01131	-0.00104	754,558,105	-0.00147	-1,109,200	9,318,793	8,209,592
SEP		7,098,691	-16,499	-21,969	7,060,223	638,375,516	0.01106	-0.00129	718,373,731	-0.00130	-933,886	8,871,916	7,938,030
OCT		6,714,213	-16,024	-198,639	6,499,550	584,268,170	0.01112	-0.00123	591,324,466	-0.00104	-614,977	7,302,857	6,687,880
NOV		6,611,224	-14,566	-102,845	6,493,813	575,410,409	0.01129	-0.00106	558,650,753	-0.00129	-720,659	6,899,337	6,178,677
DEC		6,968,466	-35,293	6,138	6,939,311	601,002,106	0.01155	-0.00080	589,258,752	-0.00123	-724,788	7,277,346	6,552,557
JAN	1980	$7,395,276	-$43,059	$59,484	$7,411,701	640,738,485	$0.01157	-$0.00078	631,527,301	-$0.00106	-$669,419	$7,799,362	$7,129,943
FEB		7,219,921	-20,353	25,681	7,225,249	613,607,185	0.01178	-0.00057	633,103,980	-0.00080	-506,483	7,818,834	7,312,351
MAR		7,487,189	-10,066	-22,660	7,454,463	616,174,650	0.01210	-0.00025	611,687,505	-0.00078	-477,116	7,554,341	7,077,224
APR		6,588,682	-14,284	-27,668	6,546,730	536,303,040	0.01221	-0.00014	565,066,175	-0.00057	-322,088	6,978,567	6,656,480
MAY		7,125,162	-91,144	-21,513	7,012,505	567,549,129	0.01236	0.00001	530,124,546	-0.00025	-132,531	6,547,038	6,414,507
JUN		8,105,545	-165,580	11,505	7,951,470	659,979,758	0.01205	-0.00030	618,482,141	-0.00014	-86,587	7,638,254	7,551,667
JUL		10,841,883	-31,041	-1,931	10,808,911	859,338,586	0.01258	0.00023	760,680,715	0.00001	7,607	9,394,407	9,402,014
AUG		11,119,823	-69,354	61,073	11,111,542	855,917,986	0.01298	0.00063	863,556,380	-0.00030	-259,067	10,664,921	10,405,854
SEP		8,805,940	-14,460	14,581	8,806,061	683,437,217	0.01288	0.00053	795,941,617	0.00023	183,067	9,829,879	10,012,946
OCT		7,541,489	-2,344	145,690	7,684,835	584,548,165	0.01315	0.00080	624,664,120	0.00063	393,538	7,714,602	8,108,140
NOV		7,059,946	-1,125	68,339	7,127,160	574,554,630	0.01240	0.00005	554,496,140	0.00053	293,883	6,848,027	7,141,910
DEC		7,684,084	-3,207	-13,234	7,667,643	619,041,050	0.01239	0.00004	601,091,254	0.00080	480,873	7,423,477	7,904,350
JAN	1981	$8,674,025	-12,141	-$5,041	$8,656,843	670,698,632	$0.01291	$0.00056	675,380,364	$0.00005	$33,769	$8,340,947	$8,374,717
FEB		7,563,169	-6,009	-231	7,556,929	577,233,600	0.01309	0.00074	624,815,879	0.00004	24,993	7,716,476	7,741,469
MAR		7,734,091	-5,875	49,071	7,777,287	601,770,235	0.01292	0.00057	583,071,810	0.00056	326,520	7,200,937	7,527,457
APR		7,434,266	-8,976	23,547	7,448,837	544,279,497	0.01369	0.00134	545,413,351	0.00074	403,606	6,735,855	7,139,461
MAY		7,771,548	-2,749	33,944	7,802,743	570,023,442	0.01369	0.00134	542,219,520	0.00057	309,065	6,696,411	7,005,476
JUN		10,774,549	-123,503	-162,910	10,488,136	734,501,584	0.01428	0.00193	665,854,376	0.00134	892,245	8,223,302	9,115,546
JUL		11,091,617	-79,381	-298,292	10,713,944	828,151,537	0.01294	0.00059	792,629,426	0.00134	1,062,123	9,788,973	10,851,097
AUG		10,642,188	-24,509	-68,091	10,549,588	767,844,458	0.01374	0.00139	769,781,912	0.00193	1,485,679	9,506,807	10,992,486
SEP		8,584,858	-73,252	72,272	8,583,878	623,608,260	0.01376	0.00141	705,656,033	0.00059	416,337	8,714,852	9,131,189
OCT		7,756,852	-18,909	256,206	7,994,149	571,878,575	0.01398	0.00163	583,523,750	0.00139	811,098	7,206,518	8,017,616
NOV		7,292,818	-19,762	109,093	7,382,149	552,745,178	0.01336	0.00101	546,237,463	0.00141	770,195	6,746,033	7,516,227
DEC		8,787,129	-27,217	10,412	8,770,324	604,507,328	0.01451	0.00216	565,491,105	0.00163	921,751	6,983,815	7,905,566
JAN	1982	$9,852,129	-$28,399	-$99,510	$9,724,220	670,401,206	$0.01451	$0.00216	651,270,182	$0.00101	$657,783	$8,043,187	$8,700,970
FEB		8,710,670	-36,228	-84,659	8,589,783	574,042,118	0.01496	0.00261	643,701,267	0.00216	1,390,395	7,949,711	9,340,105
MAR		8,771,457	-84,358	173,044	8,860,143	575,493,352	0.01540	0.00305	590,288,362	0.00216	1,275,023	7,290,061	8,565,084
APR		7,823,720	-61,128	54,457	7,817,049	540,119,589	0.01447	0.00212	553,177,382	0.00261	1,443,793	6,831,741	8,275,534
MAY		9,112,824	-78,272	35,997	9,070,549	621,406,576	0.01460	0.00225	563,691,124	0.00305	1,719,258	6,961,585	8,680,843
JUN		9,832,025	-125,598	-231,279	9,475,148	636,686,332	0.01488	0.00253	649,213,674	0.00212	1,376,333	8,017,789	9,394,122
JUL		12,240,858	-132,316	-148,422	11,960,120	784,620,291	0.01524	0.00289	687,371,959	0.00225	1,546,587	8,489,044	10,035,631
AUG		11,012,894	-15,281	-263,476	10,734,137	696,272,474	0.01542	0.00307	740,827,011	0.00253	1,874,292	9,149,214	11,023,506
SEP		9,351,210	-62,640	428,269	9,716,839	585,773,913	0.01659	0.00424	636,430,474	0.00289	1,839,284	7,859,916	9,699,200
OCT		8,667,327	-30,094	395,853	9,033,086	571,667,760	0.01580	0.00345	567,330,165	0.00307	1,741,704	7,006,528	8,748,231
NOV		8,203,027	-185,690	214,110	8,231,447	540,057,795	0.01524	0.00289	535,276,154	0.00424	2,269,571	6,610,661	8,880,231
DEC		8,768,034	-74,597	67,825	8,761,262	567,481,904	0.01544	0.00309	552,008,451	0.00345	1,904,429	6,817,304	8,721,734

		FUEL COST	LESS: FORCED OUTAGE	COMMISSION PROPOSAL LESS OVER/ PLUS UNDER RECOVERY	FUEL INCLUDING OVER/UNDER RECOVERY	DETERMINATION KWH	COST / KWH	FAC CHG.	APPLICABLE KWH	UNIT CHARGE	FAC REVENUE	BASE REVENUE	TOTAL RECOVERY
JAN	1983	$9,085,269	-$70,357	-$178,750	$8,836,162	629,424,898	$0.01404	$0.00169	601,909,166	$0.00289	$1,739,517	$7,433,578	$9,173,096
FEB		7,933,385	-13,858	-135,048	7,784,479	562,468,528	0.01384	0.00149	611,186,900	0.00309	1,888,568	7,548,158	9,436,726
MAR		8,430,544	-20,055	62,109	8,472,598	592,690,735	0.01430	0.00195	592,674,228	0.00169	1,001,619	7,319,527	8,321,146
APR		7,892,339	-2,232	5,209	7,895,316	542,273,115	0.01456	0.00221	558,972,641	0.00149	832,869	6,903,312	7,736,181
MAY		8,394,405	-106,013	101,636	8,390,028	553,555,239	0.01516	0.00281	540,569,702	0.00195	1,054,111	6,676,036	7,730,147
JUN		9,883,251	-20,372	-113,608	9,749,271	683,654,395	0.01426	0.00053	593,679,563	0.00221	1,312,032	7,331,943	8,643,974
JUL		13,239,796	-45,576	-602,804	12,591,416	858,721,589	0.01466	-0.00045	768,076,250	0.00281	2,158,294	11,605,632	13,763,926
AUG		13,476,576	-14,400	-113,668	13,348,508	878,251,187	0.01520	0.00009	898,122,836	0.00053	476,005	13,570,636	14,046,641
SEP		9,765,816	-20,971	-22,648	9,722,197	668,142,948	0.01455	-0.00056	808,393,780	-0.00045	-363,777	12,214,830	11,851,053
OCT		8,445,995	-10,700	24,184	8,459,479	573,881,905	0.01474	-0.00037	609,543,864	0.00009	54,859	9,210,208	9,265,067
NOV		8,059,072	-32,316	-62,676	7,964,080	573,295,336	0.01389	-0.00122	556,221,316	-0.00056	-311,484	8,404,504	8,093,020
DEC		10,869,504	-13,186	12,855	10,869,173	683,451,324	0.01590	0.00079	608,624,005	-0.00037	-225,191	9,196,309	8,971,118
JAN	1984	$10,304,206	-112,789	$147,968	$10,339,385	689,315,665	$0.01500	-0.00011	694,580,909	-$0.00122	-$847,389	$10,495,118	$9,647,729
FEB		8,336,154	-63,600	18,629	8,291,183	583,001,523	0.01422	-0.00089	659,869,989	0.00079	521,297	9,970,636	10,491,933
MAR		9,276,660	-8,358	-7,276	9,261,026	640,377,517	0.01446	-0.00065	623,174,677	-0.00011	-68,549	9,416,169	9,347,620
APR		8,386,855	-11,214	5,364	8,381,005	563,719,657	0.01487	-0.00024	589,028,289	-0.00089	-524,235	8,900,217	8,375,982
MAY		8,783,262	-22,357	-45,659	8,715,246	593,872,877	0.01468	-0.00043	570,133,365	-0.00065	-370,587	8,614,715	8,244,128
JUN		12,315,725	-80,622	30,698	12,265,801	788,729,839	0.01555	0.00044	691,629,068	-0.00024	-165,991	10,450,515	10,284,524
JUL		11,668,231	-35,972	81,136	11,713,395	781,144,888	0.01500	-0.00011	782,561,680	-0.00043	-336,502	11,824,507	11,488,005
AUG		12,109,123	-33,937	1,709	12,076,895	807,426,157	0.01496	-0.00015	784,846,550	0.00044	345,332	11,859,031	12,204,364
SEP		9,103,280	-18,555	-7,314	9,077,411	634,741,975	0.01430	-0.00081	714,654,099	-0.00011	-78,612	10,798,423	10,719,811
OCT		8,616,719	-18,597	-30,956	8,567,166	604,272,913	0.01418	-0.00093	601,052,111	-0.00015	-90,158	9,081,897	8,991,740
NOV		8,356,179	0	-38,584	8,317,595	595,349,867	0.01397	-0.00114	587,107,170	-0.00081	-475,557	8,871,189	8,395,633
DEC		9,905,679	-98,029	21,480	9,829,130	608,478,872	0.01615	0.00104	627,369,580	-0.00093	-583,454	9,479,554	8,896,101
JAN	1985	$11,418,068	-$17,098	$65,129	$11,466,099	735,176,841	$0.01560	$0.00049	652,480,583	-$0.00114	-$743,828	$9,858,982	$9,115,154
FEB		9,385,792	0	-100,764	9,285,028	625,158,933	0.01485	-0.00026	705,367,062	0.00104	733,582	10,658,096	11,391,678
MAR		9,546,765	0	57,752	9,604,517	608,221,824	0.01579	0.00068	617,315,172	0.00049	302,484	9,327,632	9,630,117
APR		8,502,352	-20,329	-8,891	8,473,132	589,205,804	0.01438	-0.00073	590,963,157	-0.00026	-153,650	8,929,453	8,775,803
MAY		8,934,789	-12,978	9,322	8,931,133	631,040,365	0.01415	-0.00096	594,513,265	0.00068	404,269	8,983,095	9,387,364
JUN		10,207,368	-18,067	57,446	10,246,747	704,089,152	0.01455	-0.00056	667,898,900	-0.00073	-487,566	10,091,952	9,604,386
JUL		12,108,366	-13,574	115,267	12,210,059	815,574,885	0.01497	-0.00014	751,110,552	-0.00096	-721,066	11,349,280	10,628,214
AUG		11,418,580	-10,000	67,740	11,476,320	791,392,833	0.01450	-0.00061	825,054,093	-0.00056	-462,030	12,466,567	12,004,537
SEP		10,247,301	-10,719	-7,141	10,229,441	695,648,290	0.01470	-0.00041	764,568,833	-0.00014	-107,040	11,552,635	11,445,595
OCT		8,879,052	-41,973	-97,964	8,739,115	625,872,361	0.01396	-0.00115	630,796,491	-0.00061	-384,786	9,531,335	9,146,549
NOV		8,645,071	-12,275	-43,813	8,588,983	591,119,184	0.01453	-0.00058	588,786,767	-0.00041	-241,403	8,896,568	8,655,165
DEC		10,468,421	-30,457	12,137	10,450,101	691,339,432	0.01512	0.00001	636,426,256	-0.00115	-731,890	9,616,401	8,884,511
JAN	1986	$9,796,383	-$15,486	$49,804	$9,830,701	690,789,400	$0.01423	-$0.00088	676,987,589	-$0.00058	-$392,653	$10,229,282	$9,836,630
FEB		9,053,647	-28,498	358	9,025,507	605,129,377	0.01492	-0.00019	655,537,806	0.00001	6,555	9,905,176	9,911,732
MAR		9,083,932	-28,426	-28,916	9,026,590	624,884,143	0.01445	-0.00066	657,930,140	-0.00088	-578,979	9,941,324	9,362,346
APR		8,306,232	-22,927	-1,009	8,282,296	597,198,389	0.01387	-0.00124	599,816,610	-0.00019	-113,965	9,063,229	8,949,264
MAY		9,461,763	10,921	-1,747	9,470,937	660,437,640	0.01434	-0.00077	622,236,720	-0.00066	-410,676	9,401,997	8,991,321
JUN		11,783,719	-9,737	155,539	11,929,521	799,497,070	0.01492	-0.00019	722,633,211	-0.00124	-896,065	10,918,988	10,022,923
JUL		13,661,286	-38,913	164,186	13,786,559	934,887,696	0.01475	-0.00036	873,666,713	-0.00077	-672,723	13,201,104	12,528,381
AUG		11,201,133	-18,246	5,765	11,188,652	780,167,402	0.01434	-0.00077	829,836,956	-0.00019	-157,669	12,538,836	12,381,167
SEP		10,616,589	-8,236	-70,161	10,538,192	727,068,311	0.01449	-0.00062	739,997,393	-0.00036	-266,399	11,181,361	10,914,962
OCT		9,010,883	6,518	-52,827	8,964,574	646,039,119	0.01388	-0.00123	711,561,412	-0.00077	-547,902	10,751,693	10,203,791
NOV		8,902,681	-14,992	-73,426	8,814,263	615,233,490	0.01433	-0.00078	608,639,492	-0.00062	-377,356	9,196,543	8,819,186
DEC		9,529,790	-23,689	960	9,507,061	679,041,254	0.01400	-0.00111	646,819,879	-0.00123	-795,588	9,773,448	8,977,860

		FUEL COST	LESS: FORCED OUTAGE	COMMISSION PROPOSAL LESS OVER/ PLUS UNDER RECOVERY	FUEL INCLUDING OVER/UNDER RECOVERY	DETERMINATION KWH	COST / KWH	FAC CHG.	APPLICABLE KWH	UNIT CHARGE	FAC REVENUE	BASE REVENUE	TOTAL RECOVERY
JAN	1987	$9,789,579	-15,365	$40,249	$9,814,463	708,458,076	$0.01385	-0.00126	666,835,301	-$0.00078	-$520,132	$10,075,881	$9,555,750
FEB		8,399,216	-11,780	3,189	8,390,625	612,525,766	0.01370	-0.00141	681,914,489	-0.00111	-756,925	10,303,728	9,546,803
MAR		8,865,203	-69,672	-59,706	8,735,825	636,818,570	0.01372	-0.00139	661,072,572	-0.00126	-832,951	9,988,807	9,155,855
APR		8,724,073	-11,433	-11,872	8,700,768	600,744,664	0.01448	-0.00063	604,105,994	-0.00141	-851,789	9,128,042	8,276,252
MAY		10,435,507	-1,017	40,194	10,474,684	746,621,109	0.01403	-0.00108	665,735,060	-0.00139	-925,372	10,059,257	9,133,885
JUN		11,618,765	-3,357	132,728	11,748,136	838,433,466	0.01401	-0.00110	811,423,397	-0.00063	-511,197	12,260,608	11,749,411
JUL		12,856,610	-8,713	126,732	12,974,629	910,516,624	0.01425	-0.00086	863,965,915	-0.00108	-933,083	13,054,525	12,121,442
AUG		13,215,484	-6,375	94,228	13,303,337	920,769,307	0.01445	-0.00066	924,095,119	-0.00110	-1,016,505	13,963,077	12,946,573
SEP		10,096,793	-8,896	-94,493	9,993,404	723,512,393	0.01381	-0.00130	800,640,695	-0.00086	-688,551	12,097,681	11,409,130
OCT		8,786,049	-481	-170,648	8,614,920	637,735,904	0.01351	-0.00160	662,212,231	-0.00066	-437,060	10,006,027	9,568,967
NOV		8,613,694	-2,961	-128,487	8,482,246	623,019,208	0.01361	-0.00150	624,676,588	-0.00130	-812,080	9,438,863	8,626,784
DEC		9,918,628	-12,745	15,891	9,921,774	688,550,872	0.01441	-0.00070	647,667,744	-0.00160	-1,036,268	9,786,260	8,749,991
JAN	1988	$10,551,025	-$9,979	$148,906	$10,689,952	749,097,296	$0.01427	-$0.00084	722,290,090	-$0.00150	-$1,083,435	$10,913,803	$9,830,368
FEB		9,625,541	8,335	20,205	9,654,081	684,902,221	0.01410	-0.00101	717,414,614	-0.00070	-502,190	10,840,135	10,337,945
MAR		9,435,164	-65,840	-43,076	9,326,248	678,160,447	0.01375	-0.00136	697,816,187	-0.00084	-586,166	10,544,003	9,957,837
APR		8,341,574	-6,836	-43,122	8,291,616	607,596,805	0.01365	-0.00146	642,207,596	-0.00101	-648,630	9,703,757	9,055,127
MAY		9,541,364	-5,843	-64,979	9,470,542	687,444,652	0.01378	-0.00133	630,382,017	-0.00136	-857,320	9,525,072	8,667,753
JUN		11,843,685	-7,081	240,233	12,076,837	853,325,744	0.01415	-0.00096	772,140,208	-0.00146	-1,127,325	11,667,039	10,539,714
JUL		13,391,680	-46,076	317,607	13,663,211	949,394,150	0.01439	-0.00072	926,246,663	-0.00133	-1,231,908	13,995,587	12,763,679
AUG		14,210,726	-65,164	112,409	14,257,971	994,497,365	0.01434	-0.00077	970,418,545	-0.00096	-931,602	14,663,024	13,731,422
SEP		10,140,563	-44,950	-92,215	10,003,398	723,512,158	0.01383	-0.00128	821,317,309	-0.00072	-591,348	12,410,105	11,818,756
OCT		8,940,432	-32,880	-249,016	8,658,536	658,408,792	0.01315	-0.00196	671,099,346	-0.00077	-516,746	10,140,311	9,623,565
NOV		8,828,524	-8,591	-84,563	8,735,370	656,048,138	0.01332	-0.00179	657,446,975	-0.00128	-841,532	9,934,024	9,092,492
DEC		10,504,421	-33,714	82,444	10,553,151	715,283,670	0.01475	-0.00036	700,471,813	-0.00196	-1,372,925	10,584,129	9,211,204
JAN	1989	$10,001,635	-9,313	$116,435	$10,108,757	715,531,116	$0.01413	-0.00098	721,095,552	-$0.00179	-$1,290,761	$10,895,754	$9,604,993
FEB		9,480,645	-9,082	-2,445	9,469,118	694,095,199	0.01364	-0.00147	708,490,740	-0.00036	-255,057	10,705,295	10,450,238
MAR		8,906,650	-11,768	3,735	8,898,617	693,513,240	0.01283	-0.00228	719,342,271	-0.00098	-704,955	10,869,262	10,164,306
APR		8,204,893	-11,134	-47,095	8,146,664	663,460,083	0.01228	-0.00283	662,057,594	-0.00147	-973,225	10,003,690	9,030,466
MAY		8,641,611	-11,166	-96,795	8,533,650	699,443,844	0.01220	-0.00291	651,059,508	-0.00228	-1,484,416	9,837,509	8,353,093
JUN		10,275,856	-7,451	380,900	10,649,305	830,709,032	0.01282	-0.00185	798,053,688	-0.00283	-2,258,492	12,058,591	9,800,099
JUL		11,598,876	-8,586	585,446	12,175,736	941,420,123	0.01293	-0.00129	900,627,978	-0.00291	-2,620,827	13,045,113	10,424,286
AUG		11,232,655	-1,854	98,756	11,329,557	930,582,203	0.01217	-0.00205	884,090,433	-0.00185	-1,635,567	12,572,547	10,936,980
SEP		9,488,940	-2,190	-88,476	9,398,274	777,774,560	0.01208	-0.00214	872,833,851	-0.00129	-1,125,956	12,411,697	11,285,742
OCT		8,317,543	-1,599	-500,161	7,815,783	691,788,820	0.01130	-0.00292	686,601,233	-0.00205	-1,407,533	9,763,470	8,355,937
NOV		8,134,220	-3,050	-235,723	7,895,447	679,330,891	0.01162	-0.00260	667,623,594	-0.00214	-1,428,714	9,493,608	8,064,893
DEC		10,134,987	-1,608	135,817	10,269,196	806,692,333	0.01273	-0.00149	738,301,470	-0.00292	-2,155,840	10,498,647	8,342,807
TOTALS*													$1,224,962,419

*Total Jan. 1979 to Dec. 1989

Commonwealth of Kentucky

County of Jefferson

I, Randall J. Walker, say that the statements contained in the foregoing testimony are true to the best of my knowledge and belief.

Dated this 6th day of November, 1990.

Randall J. Walker

SUBSCRIBED AND SWORN to before me by Randall J. Walker on this 6th day of November, 1990.

Linda E. Martin

Linda E. Martin, Notary Public
State at Large, Kentucky

My commission expires May 12, 1993.

LG&E Case No. 90-158 Rebuttal Testimony – Charles E. Olson
Responding Witness – William Steven Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	))	CASE NO. 90-158

REBUTTAL AND SUPPLEMENTAL COST OF COMMON EQUITY CAPITAL TESTIMONY OF CHARLES E. OLSON

October 1990

PREPARED REBUTTAL AND SUPPLEMENTAL TESTIMONY OF

CHARLES E. OLSON

Q. Please state your name.

A. My name is Charles E. Olson.

Q. Are you the same Charles E. Olson whose direct testimony was filed earlier in this case?

A. Yes.

Q. Have you reviewed the testimony and exhibits that have been filed in this case by Richard A. Baudino, the witness for the Kentucky Industrial Utility Customers, and Carl G.K. Weaver and Thomas C. DeWard who appear on behalf of the Attorney General?

A. Yes, I have.

Q. Do you agree with the analyses and conclusions of Mr. Baudino?

A. I agree with parts of his testimony. However, I disagree with his conclusion concerning the cost of common equity capital.

Q. What cost of common equity does Mr. Baudino recommend, and how did he obtain his result?

A. Mr. Baudino recommended a return on common equity of 11.7 percent for Louisville Gas and Electric Company (Louisville). In reaching his conclusion as to the cost of equity, Mr. Baudino relied on the discounted cash flow (DCF) and interest premium approaches. His DCF estimates are based on results for the group of comparable electric companies I used in my direct testimony as well as on data for Louisville. His interest premium conclusion is a function of his DCF results for the group of electrics and bond yields for the group and for Louisville.

Q. Turning to Mr. Baudino's DCF analyses, what is your first disagreement with his implementation of this approach?

A. I believe he has underestimated the cost of equity to Louisville because his dividend yields are not up to date. Mr. Baudino's testimony was filed at the end of September. Yet, his dividend yields extend only through July. Schedule No. 1 of my rebuttal exhibit shows that the average dividend yield for the six month period ending September 1990 for the group of electrics is 7.41 percent, and for Louisville the dividend yield for that more recent six month period is 7.46 percent. In both cases, the more current yield is about 20 basis points higher than the yields used by Mr. Baudino.

Q. How did Mr. Baudino estimate expected growth for the group of electric companies and for Louisville?

A. He calculated averages of the following growth rates:

1. Compound dividend per share growth rate from 1990 to 1994 from Value Line.
2. Compound earnings per share growth rate from 1990 to 1994 from Value Line.
3. The IBES earnings growth projection.

Mr. Baudino gave equal weight to each of these growth rates. I note, however, that he has relied on different factors and different weights in previous testimony. Given this, it seems that Mr. Baudino's weighted average growth rates of 4.28 percent for the group and 3.46 percent for Louisville certainly reflect his judgment. Reliance on judgment is something for which Mr. Baudino criticized me.

It is important to note that the most forward-looking of the three growth estimates employed by Mr. Baudino is a five year growth rate. Thus, any improvement in growth beyond the end of the projection period is not recognized.

Comparison of Value Line's projected dividend and earnings growth rates, shown on Mr. Baudino's Table 2, along with the projected retention growth rates on Table 4, shows the importance of looking beyond the end of the near-term projection periods. Value Line's average projected earnings growth rate for the group of electrics is 5.53 percent, but their projected dividend growth rate for the next few years is 3.85 percent. The increase in book value through retention growth is projected to be 3.76 percent. Since Value Line expects earnings increases on the order of 5.5 percent, and earnings are either paid out as dividends or retained as book value, it is reasonable to expect that, in the long-term, dividend and book value growth rates will tend to increase at higher rates as well. Value Line apparently does not think this will happen in the next four or five years, but their data do suggest that long-term expected growth is likely to be greater than growth expected for the next few years.

Q. Does the same relationship hold true for Louisville?

A. Generally, it does. Mr. Baudino did not provide a retention growth rate for Louisville as part of his DCF analysis. However, in his rebuttal of my testimony, he stated that Value Line's projected retention growth rate is 2.9 percent. Value Line's estimate of the Company's earnings growth rate through 1994 is 4.93 percent, or two to three times its projected dividend growth rate of 1.74 percent, and close to twice its projected retention growth rate. This suggests to me that their estimates of dividend and retention growth are not representative of long-term expectations.

It is important to note that the IBES growth rate Mr. Baudino relies on for Louisville is 3.7 percent, but the current mean IBES estimate is 4.9 percent. Obviously, the use of this more recent growth rate would increase Mr. Baudino's weighted average growth rate for Louisville. Also, both the Value Line and the IBES estimates of expected earnings growth are within the projected growth rate range of 4.75 to 5.25 percent I used in my DCF analysis. Finally, at page 21 of his testimony, Mr. Baudino states that his DCF estimate for Louisville -- 10.7 percent -- "...is probably too conservative." I believe this is because he failed to consider probable trends in growth beyond the end of the Value Line and IBES projection periods.

Q. You stated earlier that Mr. Baudino relied on the DCF and interest premium approaches in estimating Louisville's cost of equity capital. Please explain his application of the interest premium approach.

A. Mr. Baudino computed an average DCF return requirement for the group of comparison companies, subtracted an average bond yield for those companies to get a risk premium, and then added that premium to a yield for Louisville's bonds to get an estimate of the return requirement for Louisville.

Q. Do you have any comments on Mr. Baudino's risk premium analysis?

A. Yes. The risk premium analysis Mr. Baudino performed is no better than the DCF method that determined the cost rate for common equity. Since, in my opinion, the results of his DCF study understate cost of equity in this case, it is axiomatic that I believe his return requirement developed using the interest premium approach is too low as well.

At page 26 of his testimony, Mr. Baudino says that his recommendation of a cost of equity for Louisville is "...based on averaging the results of the comparison group analysis utilizing analysts' forecasts and the risk premium analysis." However, since the bond yields of the companies in the group are virtually equal to Louisville's bond yield, as one would expect them to be since the companies were chosen for their comparability to Louisville, there is really no separate risk premium analysis. Mr. Baudino has merely subtracted a bond yield amount from his DCF results for the group and added the result back to Louisville's bond yield, which, by definition, is practically the same. Further, Mr. Baudino did not say which bonds are represented by the data he shows in his Table 8, and he did not provide a source for those bond yields. Therefore, is would be difficult to evaluate the data in Table 8 or to update the table.

Q. Are there other indications that Mr. Baudino's risk premium for the group, and therefore for Louisville, is too low?

A. Yes. There are other sources of data that provide a comparison between common stock returns and the returns on corporate bonds. One such source is the Paine Webber study I described in my direct testimony. Another well known study on this subject is updated and published annually by Ibbotson Associates of Chicago. The most recent of those publications is titled <u>Stocks Bonds Bills and Inflation, 1990 Yearbook - Market Results for 1926-1989</u>. The Ibbotson data show that over the 1926 to 1989 period, common stock returns have averaged 12.4 percent, and long-term corporate bond returns have averaged 5.5 percent. The difference between these figures of 6.9 percent is the average risk premium over the period of over 60 years. I am not suggesting that risk premiums have been constant over that period or that the risk premium for Louisville's stock over its yield bond is 6.9 percent at this time, but I do believe that the Ibbotson data provide an indication that Mr. Baudino's estimate of the risk premium for the group of electrics and for Louisville is quite low.

Q. Did Mr. Baudino include an allowance for flotation costs in his cost of common equity capital for Louisville?

A. No. At page 21 of his testimony, Mr. Baudino says:

> ...the problem with making an adjustment for flotation costs in the cost of equity calculation is that it assumes that all future issuances will have the same expenses associated with them. This is simply not a valid assumption, and would cause ratepayers to shoulder a cost burden which the utility may never incur.

Mr. Baudino fails to mention that if flotation costs are not estimated correctly, there is also a chance that utilities will not recover the costs they do incur. If no allowance is made for flotation costs, this will surely be the case.

As an alternative to adjusting the return requirement, Mr. Baudino suggests that the Commission allow Louisville to collect flotation costs in the cost of service. However, it has not been the practice of the Commission to collect flotation costs in this way. The point to be made here is that if the Commission does not see fit to adopt the approach Mr. Baudino suggests, then the investors' return requirement should be adjusted for flotation costs as I have recommended.

In discussing a flotation cost adjustment, Mr. Baudino also mentions that it is unclear that Louisville will be making any public issuances of common stock in the near future. I explained in my direct testimony why an adjustment should be made for flotation costs whether or not a company has current plans for a public issue of stock.

Finally, Mr. Baudino says that a market-to-book adjustment is completely unjustified because Louisville's market-to-book ratio is already above one. This, of course, is an inappropriate argument because, if Louisville's required return is allowed and earned, the Company's market-to-book ratio would tend to be one unless an adjustment for financing costs or market breaks is made. If common shares are issued when the market-to-book ratio is about one, the result of having to subtract underwriting and other expenses from the amount paid by investors is that net proceeds per share received by the Company are below book value and the market-to-book ratio then is below one. In other words, dilution of the existing shareholders' investment occurs. For this reason, Mr. Baudino is incorrect to conclude that a market-to-book ratio is unjustified because Louisville's market-to-book ratio is currently above one. I wonder if he would have recommended an upward adjustment if the Company's price had been below book value.

Q. At page 28 of his testimony, Mr. Baudino says that you erred in your calculation of retention growth. Is he correct?

A. No, he is not. In estimating expected retention growth, I first calculated an estimate of retention growth based on Louisville's 1989 return on equity of 11.1 percent and its 1989 retention ratio of 14.1 percent. Combining these two figures produced a retention growth figure of 1.6 percent. I believe even Mr. Baudino would agree that this growth rate is not representative of long-term expectations. Next, I stated that I believe investors expect future returns for Louisville on the order of 14.5 percent. Since this figure is 3.4 percent greater than the 1989 return, I added 3.4

percent to the 1989 retention growth figure. The resulting expected growth rate is 5.0 percent.

Mr. Baudino says my calculation is wrong because, assuming investors expect a return of 14.5 percent for Louisville, a forward looking retention growth rate would be calculated by multiplying the expected return by the 1989 retention ratio. The flaw in his reasoning is obvious. If earnings are expected to improve, then the retention ratio also would be expected to improve.

For example, if a utility's earnings per share are $1.00, its dividends per share are $.80, and its average book value per share is $10, its retention ratio would be 20 percent (1-$.80/$1.00) and its return on equity would be 10 percent ($1/$10). The company's retention growth rate, therefore, would be 2 percent (.20 x .10). However, if its return on equity is expected to be 12 percent, then earnings per share would be expected to be $1.20 (.12 x $10). Assuming that dividends remain at $.80, the expected retention ratio would become 33 percent (1-$.80/$1.20), and the retention growth rate would be 4 percent (.33 x .12). In other words, the retention growth rate has increased by the same amount as the expected increase in return on equity. If, on the other hand, the retention ratio remained at 20 percent, as Mr. Baudino suggests would be the case, then the dividend would increase by $.20 ($1.20-$1.00) to $1.00. This represents a 25 percent increase in dividends per share. I believe it is Mr. Baudino who fails to understand the mathematics of this situation.

Q. Please turn now to the testimony of Dr. Weaver. What cost of common equity capital did Dr. Weaver recommend, and how did he arrive at this estimated cost?

A. He recommended a cost rate for common equity of 12.0 to 12.5 percent based on DCF analyses of Louisville and a group of comparable companies.

Q. What investor return requirements did Dr. Weaver's DCF studies produce for Louisville and the comparable companies?

A. For Louisville, the return requirement was 11.74 to 12.27 percent. For the comparables, his estimated cost rate was 12.06 to 12.60 percent.

Q. What are your primary areas of disagreement with Dr. Weaver's study?

A. I believe he underestimated the expected growth rate for Louisville he used in his DCF analysis and that he should have included a market-to-book adjustment to account for the costs associated with issuing common stock.

Q. Please describe Dr. Weaver's approach to estimating expected growth and explain why you believe Dr. Weaver has underestimated expected growth.

A. Dr. Weaver calculated historical compound growth rates in earnings, dividends, and book value per share as well as average retention growth rates for the period 1979 to 1989. Although I agree that historical growth rates should be considered in estimating expected future growth, I believe projected growth rate data should be considered as well.

Dr. Weaver has failed to do this. I note that in his testimony in Louisville's last rate case he relied entirely on Value Line's projected retention growth figures. Dr. Weaver did adjust the historical growth rate he found for Louisville because, in his opinion, the historical growth rate underestimates expectations for the future. At page 28 of his testimony he says:

> The dividend yield of LG&E indicated to me that investors expect higher growth in the future than what has been achieved in the past. For this reason, I used the higher growth achieved by the five companies rather than the low growth achieved by LG&E to formulate this estimate.

He adds that, for consistency, he also used the DCF calculation for the five similar companies in formulating his final recommendation. In fact, his final recommendation of 12.0 to 12.5 percent is quite close to his DCF results for the group of 12.06 to 12.60 percent.

The expected growth rate that Dr. Weaver used for both Louisville and the group is 4.0 to 4.5 percent. As I mentioned previously, the current mean IBES consensus earnings estimate for Louisville is 4.9 percent. This indicates that Dr. Weaver was correct to conclude that higher growth is expected for Louisville in the future than has been experienced in the past. It also suggests that a forward-looking estimate that is even higher than 4.0 to 4.5 percent is appropriate.

Q. You mentioned that Dr. Weaver's recommended cost of equity for Louisville is about equal to his DCF results for his group of comparable companies. Does this seem reasonable to you?

A. Not entirely. At page 18 of his testimony, Dr. Weaver says that Louisville has slightly more risk than the group of comparable companies. To the extent that Louisville's risk is greater, its return should be greater as well.

Q. Why did Dr. Weaver say he did not include a market-to-book adjustment to the investor return requirement?

A. The first reason he gave is that Louisville does not have any current plans to issue common stock. I have already explained why it is proper to make an adjustment even if a firm has no plans to issue additional common shares to the public. Secondly, Dr. Weaver pointed out that Louisville's market-to-book ratio at the time he prepared his testimony was already above one. He added that when investor expectations are ignored, the application of a market determined cost of equity to a book value capital structure may cause market prices to converge toward book value. However, he next assumed that because the Commission has not made a market-to-book adjustment in recent decisions, investors do not expect one now and have adjusted the price they are willing to pay for Louisville's shares accordingly. I do not believe Dr. Weaver has provided adequate support for this assumption. Also, I note that in response to the Company's data requests (Question No. 10), Dr. Weaver said:

> The Public Service Commission is called upon to make numerous decisions and as circumstances change, the decisions may change. I believe that

investors would be foolish to rely too heavily on past decisions as determinants for future decisions.

Because Dr. Weaver has not made an adjustment for the costs associated with common share issuances, I believe he has underestimated the cost of equity to Louisville.

Q. You have mentioned that both Mr. Baudino and Dr. Weaver stated that one reason they did not include a market-to-book adjustment for flotation costs is that Louisville has no current plans to issue common stock. Can you provide additional support for your belief that an adjustment is necessary whether or not a utility has plans to issue new shares in the near-term?

A. Yes. Myron Gordon has explained that a regulatory agency must:

> ... estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of the book value. The welfare of the stockholders is independent of the firm's stock financing rate, and the utility may be expected to set the stock financing rate to satisfy the demand for service.*

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* Myron J. Gordon, <u>The Cost of Capital to a Public Utility</u>. East Lansing, 1974, pp. 165-66. Footnote reference omitted.

Q. Have other authors addressed this issue?

A. Yes. Another article on flotation costs which addresses this issue is entitled "Common Equity Flotation Costs and Rate-Making" by Eugene F. Brigham, Ph.D, Dana A. Aberwald, CPA, and Louis C. Gapenski, all of the University of Florida. The article was published in the Public Utilities Fortnightly, May 2, 1985, pages 28 through 36. Dr. Brigham et al. discuss the need for including an adjustment for flotation cost to "market-determined cost of equity" such as the discounted cash flow (DCF) method. On page 28 of the Bringham et al. article it states:

> Specifically, the market-determined cost of equity should be adjusted (increased) to reflect issuance costs associated with past issues regardless of whether the company plans to issue stock in the future or not, and the adjustment should be applied to the total common equity, including retained earnings.

Continuing on page 28:

> The flotation cost adjustment - whether bonds, preferred stocks, or common equity - is designed to convert market rate of return into fair rate of return on accounting book values.

In the conclusion, at page 36, Brigham summarizes the results of the article by saying:

> Further, the adjustment is always required, irrespective of whether or not a company plans to sell new stock in the future, and the adjusted return must be earned on total equity, including retained earnings. Otherwise, it would be impossible for investors to earn the cost of equity, even under prudent and efficient management.

Also, Roger A. Morin, Ph.D, Professor of Finance at Georgia State University, in his book Utilities Cost of Capital, (Arlington, Virginia: Public Utilities Reports, Inc., 1984), states on page 108:

> It is important to note that under the conventional approach [to the DCF model], flotation costs are only recovered if the rate of return is

> applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated.

Another author, Cleveland S. Patterson, Ph.D., Associate Professor of Finance, Concordia University in Montreal, writes in the July 16, 1981 Public Utilities Fortnightly an article entitled, "Issue Costs in the Estimation of the Cost of Equity Capital" (pages 28 through 32). He states on page 30 that "...the issue costs could be amortized by means of perpetual increment to the rate of return [on common equity.]" He goes on to say that this perpetual increment would be appropriate in all years after issuance.

In another article by Patterson entitled, "Flotation Cost Allowance in Rate of Return Regulation: Comment," published in The Journal of Finance, September 1983, pages 1335 through 1338, he writes on page 1136:

> ...r' [the required rate of return on equity adjusted for flotation cost] is independent of the rate of external financing and is applied to the equity base in every year whether new financing is contemplated or not.

He continues on page 1337:

> ...in other words, the flotation cost adjustment is not made to reflect current or future financing costs...; it is made to compensate investors for costs incurred in preceding stock issues.

Q. Dr. Olson, do you have any comments on the testimony of the Attorney General's accounting witness, Thomas C. DeWard with respect to capital structure?

A. Yes. Mr. DeWard recommends reducing Louisville's common equity ratio by 25 percent of the cost of Trimble County. He makes this recommendation because 25 percent of Trimble County's capacity and cost will not be reflected in Louisville's rates.

Q. Is this an appropriate adjustment?

A. No, it is not. Mr. DeWard's adjustment is based, implicitly at least, on the assumption that the below-the-line portion of Trimble County could not carry any debt capital if it were financed on a stand-alone basis, but this is simply not true. Trimble County is a new unit that was built below budgeted costs. No economic case can be made for treating the 25 percent below-the-line share of Trimble County as a 100 percent equity financed investment.

Q. Can an accounting case be made for such treatment?

A. No. No write-off of the investment is expected. Therefore, there will be no reduction in Louisville's common equity. Under the circumstances, it is reasonable to assume that all of the assets are financed by the entire capitalization.

Q. What would be the effect of reducing Louisville's common equity ratio by 25 percent of the cost of Trimble County?

A. The common equity ratio would be reduced to 35 percent, and Louisville's bond rating would decline to Baa/BBB. A far higher return on common equity would be required.

Q. Have you updated your direct testimony?

A. Yes.

Q. What is Louisville's updated dividend yield?

A. Louisville's dividend yield for the period of about six months beginning May 1 and ending October 26, 1990 was 7.57 percent. The high price during this period was $39.75, the low price was $35.25, and the average price was $37.50. The dividend rate employed in the yield calculation is $2.84; this is the current dividend rate and also the projected rate through September 1991.

Q. What long-term growth rate do you believe investors expect for Louisville at this time?

A. I continue to believe that investors expect Louisville's long-term growth to be 4.75 to 5.25 percent. As I pointed out previously, the IBES consensus estimate of expected earnings growth has increased to 4.9 percent, or to about the mid-point of this growth rate range.

When the dividend yield of 7.57 percent and the expected growth rate of 4.75 to 5.25 percent are combined, the investor return requirement becomes 12.32 to 12.82 percent. When the 8 percent market-to-book adjustment is included, the cost of equity is 13.31 to 13.85 percent.

Q. Have the results of your interest premium check of the DCF results changed as well?

A. No. The interest rate on Double A rated public utility bonds has not changed substantially since the time I prepared my direct testimony. Therefore, the 14.5 percent cost of equity I found using the interest premium approach has not changed.

Q. What is the current DCF result for the group of comparable electric companies that provided your second check of the

DCF results for Louisville?

A. The updated dividend yield for the group, shown on Schedule No. 2 of my rebuttal exhibit, is 7.48 percent for the May 1 to October 26 period. Schedule No. 3 shows the IBES growth rates for the comparable electrics as of October 1990. Although the average IBES growth rate for the group declined slightly from 3.5 percent to 3.2 percent, I believe the expected growth rate is still within the 5.0 to 5.5 percent range I found in my direct testimony. Combining the 7.48 percent dividend yield and the growth rate of 5.0 to 5.5 percent produces an investors' return requirement of 12.48 to 12.98 percent. When the market-to-book adjustment of 8 percent is included, the cost of equity becomes 13.48 to 14.02 percent. This is slightly above the cost of equity I found for Louisville.

Q. What is your current recommended return on common equity for Louisville?

A. Based primarily on my DCF study of Louisville, my recommended return at this time is 13.25 to 13.75 percent.

Q. Does this conclude your rebuttal and supplemental testimony?

A. Yes, it does.

DISTRICT OF COLUMBIA

CITY OF WASHINGTON

I, Charles E. Olson, say that the statements contained in the foregoing testimony are true to the best of my knowledge and belief.

Dated this 5th day of November, 1990.

Charles E. Olson

SUBSCRIBED AND SWORN to before me by Charles E. Olson on this 5th day of November, 1990.

Carole Y. Francis
Notary Public
Washington, D. C.

My commission expires: January 1, 1995.

LOUISVILLE GAS & ELECTRIC COMPANY

Selected Electric Companies
Dividend Yields
April - September 1990

Company	Dividend Yield
CIPSCO	8.71%
Cilcorp	7.48
IPALCO Enterprises	7.36
Kentucky Utilities	7.60
Orange & Rockland Utilities	7.98
Southern Indiana Gas & Electric	6.47
Southwestern Public Service	7.97
Teco Energy	5.69
Average	7.41%
LG&E Energy	7.46%

Source: Testimony of Richard A. Baudino, Tables 1 and 5. Standard & Poor's Stock Guide.

LOUISVILLE GAS AND ELECTRIC COMPANY

Selected Electric Utility Companies
Dividend Yields
May 1 - October 26, 1990

	(1)	(2)	(3)	(4)	(5)
	Market Price Per Share			Indicated	Dividend
Company	High	Low	Average	Dividends	Yield
CIPSCO	$22.250	$19.500	$20.875	$1.84	8.81%
Cilcorp	34.750	29.750	32.250	2.46	7.63
IPALCO Enterprises	36.375	23.125	24.750	1.80	7.27
Kentucky Utilities	20.750	17.250	19.000	1.46	7.68
Orange and Rockland Utilities	30.625	26.125	28.375	2.34	8.25
Southern Indiana Gas & Electric	30.625	27.875	29.250	1.90	6.50
Southwestern Public Service	29.375	25.125	27.25	2.20	8.07
Teco Energy	30.500	27.000	28.750	1.62	5.63
Average					7.48%

Source: Standard & Poor's Stock Guide. Barron's.

LOUISVILLE GAS & ELECTRIC COMPANY

Selected Electric Utility Companies
Projected Earnings Growth Rates

Company	5-Year Projected Growth
CIPSCO	2.2%
Cilcorp	2.8
IPALCO Enterprises	4.1
Kentucky Utilities	2.8
Orange & Rockland Utilities	2.8
Southern Indiana Gas & Electric	3.9
Southwestern Public Service	2.2
Teco Energy	5.0
Average	3.2%

Source: Institutional Brokers Estimate System, accessed through CompuServe Information Service, October 1990.

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that on the 6th day of November, 1990, the original and fifteen (15) copies of the foregoing were hand delivered to Hon. Lee M. MacCracken, Executive Director, Public Service Commission, 730 Schenkel Lane, Frankfort, KY 40602, and that each of the persons on the attached service list was served with the number of copies and in the manner indicated on the attached service list.

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LG&E Case No. 90-158 Rebuttal Testimony-Benjamin McKnight
Responding Witness – William Steven Seelye

BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF
ADJUSTMENT OF GAS AND)
ELECTRIC RATES OF)
LOUISVILLE GAS AND)
ELECTRIC COMPANY) CASE NO. 90-158

REBUTTAL TESTIMONY OF BENJAMIN A. MCKNIGHT

Q. Would you please state your name and with whom you are associated?

A. My name is Benjamin A. McKnight. I am a Certified Public Accountant and a partner with the firm of Arthur Andersen & Co., independent public accountants.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to comment on certain recommendations included in the direct testiony of Mr. Lane Kollen, on behalf of the Kentucky Industrial Utility Customers, and Mr. Thomas C. De Ward, on behalf of the Office of the Attorney General for the Commonwealth of Kentucky. Specifically, I will address Mr. Kollen's recommendation that this Commission should amortize Louisville Gas and Electric Company's (LG&E or the Company) January 1, 1990 balance of unbilled revenues over three years as a reduction in future rates. I will also address an adjustment proposed by Mr. De Ward to reduce the Company's capital structure for the test year ended April 30, 1990, for 25% of the Job Development Investment Tax Credit (JDIC) attributable to the Trimble County Unit I generation station.

Q. Do you agree with Mr. Kollen's proposal to utilize the Company's unbilled revenue balance as of January 1, 1990, $29.8 million, to reduce annual revenue requirements by $9.9 million for a three-year period?

A. No, I do not. Mr. Kollen's proposal is based on the erroneous conclusion that an accounting entry to record unbilled revenues for financial reporting purposes created a "windfall" benefit that was retained by the Company for its shareholders.

Q. Would you explain the basis of your disagreement with Mr. Kollen's conclusion?

A. Yes. In past LG&E rate cases, 12 months of revenues have been matched with 12 months of fuel, gas and other O&M expenses in order to determine a revenue deficiency or excess. In the ratemaking process there were no unbilled revenues because, in each rate case, test year adjustments were made to match 12 months of revenues and expenses and set appropriate rates based on the answer produced. The same procedure is being followed by the Company in this proceeding.

Let's now compare this regulatory treatment with the past accounting practice followed by the Company for financial reporting purposes. Prior to 1990, LG&E was one of many utilities that recorded revenue on the billed basis. As I indicated in my direct testimony, there were a number of reasons for this accounting practice, including the delay in the payment period for income taxes. The Tax Reform Act of 1986 eliminated this significant income tax related benefit. Consequently, in 1990, LG&E changed its accounting practice and began recording unbilled revenue for financial reporting purposes. The bookkeeping entry to record the $29.8 million pre-tax cumulative effect of unbilled revenues as of January 1, 1990, simply changed the Company's accounting practice to track the revenues actually produced by past regulatory treatment, instead of limiting the recognition of such revenues for financial reporting purposes to amounts billed.

This bookkeeping entry has no impact on amounts billed to customers or on LG&E's cash flow and provides no additional economic benefit to the Company's shareholders.

Q. If there is no economic benefit that results from recording unbilled revenues, what would be the effect of this Commission adopting Mr. Kollen's proposal?

A. Mr. Kollen's proposal increases ratemaking revenues for the accounting recognition of unbilled revenues. This results in a level of operating revenues for purposes of setting rates that is overstated and not representative of a 12-month period. When this excessive level of test year operating revenues is mismatched with 12-months of fuel, gas and other O&M expense, any revenue deficiency is understated. The economic effect of computing the revenue requirement deficiency with excessive operating revenues is to disallow, on a dollar-for-dollar basis, recovery of what otherwise would be allowable costs for regulatory purposes.

Q. Is that the intended result of Mr. Kollen's proposed treatment of unbilled revenues?

A. In his direct testimony, Mr. Kollen has linked his recommendation for unbilled revenue with his recommended regulatory treatment of certain downsizing costs associated with LG&E restructuring its management and professional workforce.

Mr. Kollen's testimony (page 38, line 18) states:

> "In order to be consistent with the Company's proposed treatment of the initial balance of unbilled revenue which I previously discussed, the Company should not be allowed recovery of its downsizing costs. However, if the Commission accepts my recommendation to recognize the initial balance of unbilled revenues over a three year period for ratemaking purposes, then I would recommend that LG&E be allowed to recover its downsizing costs. To reiterate, my recommendation is internally consistent and stands in direct contrast to LG&E's biased and one-sided proposed treatment. Either the Commission should recognize both the initial balance of unbilled revenues and downsizing costs for ratemaking purposes or they should both be rejected."

Q. Is there any relationship between unbilled revenues and downsizing costs?

A. No, there is not. The Company's accounting for unbilled revenues is simply a bookkeeping entry that recognizes for financial reporting purposes the revenues actually produced by past regulatory treatment.

In contrast, the Company is requesting recovery through future rates, over a three year period, the $9.5 million net cost of its downsizing program. These costs have not been previously reflected in rates or considered for regulatory treatment.

In substance, Mr. Kollen proposes to offset recovery of the Company's downsizing costs with an otherwise unrelated adjustment that would overstate regulatory operating revenues and understate any revenue requirement deficiency. The objective of Mr. Kollen's scheme is to indirectly disallow recovery of the downsizing costs and, as he states in his testimony (page 36, line 9), "to mitigate the rate effects of Trimble County."

Q. Mr. McKnight, are you recommending that this Commission reject Mr. Kollen's proposed adjustment for the initial balance of unbilled revenues?

A. Yes, I am. This Commission should accept the Company's proposed adjustments for unbilled revenues because they result in a representative 12-month level of operating revenues for setting future rates. Mr. Kollen recognizes this result on page 37 of his testimony (lines 5 through 14).

Q. Would you please comment on the adjustments to LG&E's capital structure for the test year ended April 30, 1990, that Mr. De Ward has proposed for Trimble County and the related JDIC?

A. Yes. In his direct testimony and as set forth on his Schedule 4, Mr. De Ward has proposed several adjustments to the Company's capital structure. Mr. De Ward has proposed removing 25% of the cost of the Trimble County generating station from the capital structure and attributing this disallowance to the stockholders of the Company. The amount of this cost exclusion is $169,292,671. Although Mr. De Ward attributes this cost disallowance to shareholders, the appropriateness of which will be addressed by the Company's witness, Mr. Olson, this 25% portion of the plant was financed with a variety of sources other than shareholders' equity, including preferred stock, debt and JDIC.

Mr. De Ward has also proposed a related adjustment to LG&E's capital structure to deduct 25% of the JDIC attributable to Trimble County. This proposed adjustment would reduce the Company's adjusted total capital structure by $13,323,750.

Q. If the $169,292,671 of excluded Trimble County cost was financed in part by JDIC, is Mr. De Ward's proposed reduction for the $13,323,750 appropriate?

A. No, it is not. Mr. De Ward has double counted his deductions for Trimble County with his second adjustment. Once 25% of the cost of Trimble County has been removed, the $13,323,750 has been considered because it is simply the portion of the $169,292,671 that was financed with JDIC.

The proof of this double counting is that 100% of the cost for Trimble County Unit I is $677,170,684. Mr. De Ward's two adjustments to the Company's April 30, 1990 capital structure total $182,616,421, which represents 26.97% of the cost and not 25%.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

LOUISVILLE, KENTUCKY

I, Benjamin A. McKnight, say that the statements contained in the foregoing testimony are true to the best of my knowledge and belief.

Dated this 5th day of November, 1990.

Benja A. McKnight

Benjamin A. McKnight

SUBSCRIBED AND SWORN to before me by Benjamin A. McKnight on this 5th day of November, 1990.

Sally L. Patton

Notary Public
Louisville, Kentucky

My commission expires: May 19, 1991.

LG&E Case No. 90-158 Rebuttal Testimony – M. Lee Fowler
Responding Witness – William Steven Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of

ADJUSTMENT OF GAS AND) ELECTRIC RATES OF LOUISVILLE) GAS AND ELECTRIC COMPANY)	CASE NO. 90-158

RESPONSIVE TESTIMONY ON REHEARING

OF M. LEE FOWLER

SUBMITTED MARCH 8, 1991

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

AN ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 90-158

CERTIFICATE OF SERVICE

I hereby certify that on the 8th day of March, 1991, the original and fifteen (15) copies of the following Testimony were hand-delivered to Hon. Lee M. MacCracken, Executive Director, Public Service Commission, 730 Schenkel, Frankfort, Kentucky 40602, and that each of the persons on the attached service list was served with the number of copies and in the manner indicated on the attached service list.

Respectfully submitted,

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

AN ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 90-158

RESPONSIVE TESTIMONY ON REHEARING OF
M. LEE FOWLER

Q. Please state your name.

A. M. Lee Fowler.

Q. In what capacity are you employed by Louisville Gas and Electric Company ("LG&E")?

A. I am vice president and controller of LG&E.

Q. Are you the same M. Lee Fowler who testified previously in this case?

A. Yes.

Q. What is the purpose of your testimony?

A. I will respond to the issues raised by Mr. Thomas C. DeWard and Mr. David H. Kinloch in their rehearing testimony submitted in this case. In his rehearing testimony submitted on behalf of the Attorney General's Office, Mr. DeWard addressed the issue of adjusting rate base and capitalization to reflect the test-year depreciation adjustment. Mr. Kinloch addressed the issue of storm damage normalization on behalf of Jefferson County.

RATE BASE AND CAPITALIZATION ADJUSTMENT

Q. In his rehearing testimony, Mr. DeWard maintains that LG&E's rate base should be adjusted to reflect the accumulated depreciation associated with the pro-forma level of depreciation expense determined to be appropriate for inclusion in cost of service. Did LG&E make such an adjustment in Case No. 90-158?

A. Yes. A downward adjustment of $15,333,843 was made to net original cost rate base to reflect the pro-forma adjustment to depreciation expenses that we had proposed. See Fowler Exhibit 4 (page 1, line 10) to my original direct testimony. However, it should be pointed out that we also added to rate base post test-year Trimble costs of $28,371,988 which was not allowed by the Commission. See Fowler Exhibit 4 (page 1, line 6). In the initial Order in this proceeding dated December 21, 1990 (the "Rate Order"), the Commission held that the net original cost rate base could <u>not</u> be adjusted for post test-year additions to Trimble.

Q. Mr. DeWard refers to the adjustments made by LG&E and the Commission to reduce the capital structure for excess plant and inventories and materials and supplies related to excess plant. Please comment on this discussion.

A. Mr. DeWard is discussing an issue that has no bearing on the need to reduce capitalization to reflect an adjustment to depreciation expense. These adjustments to capitalization, which relate to the 25% of Trimble not allowed in customer rates, are wholly unlike the proposed adjustment for depreciation. The 25% of Trimble is a non-jurisdictional asset. LG&E agreed to eliminate the investment in this non-jurisdictional asset through a reduction to both rate base and capitalization. Mr. DeWard is attempting to use these adjustments to support his proposal to adjust capitalization for depreciation applicable to the 75% of Trimble allowed in customer rates. His proposed adjustment relates to depreciation on a jurisdictional asset in rate base, not investment in a non-jurisdictional asset.

Q. Is it appropriate to adjust total capitalization to reflect the depreciation adjustment?

A. No. Lowering capitalization to reflect the depreciation adjustment would have the effect of projecting the capital structure beyond the end of the test year. Therefore, Mr. DeWard's proposed adjustment for a single item of expense violates the Commission's policy relating to post test-year adjustments to capitalization.

Simply stated, Mr. DeWard's entire argument is: It is proper to reduce rate base; therefore, capitalization should be reduced. However, it is no more appropriate to adjust capitalization for a pro-forma adjustment to depreciation expense, which is charged against operating income, than it is to adjust capitalization for any other adjustment to revenues or expenses. While we do not agree that an adjustment is appropriate, if total capitalization is adjusted to reflect depreciation on the 75% of Trimble County allowed in customer rates, then capitalization should be adjusted to reflect all of the other pro-forma adjustments to operating revenues and expenses, including the revenue increase.

Q. Wouldn't this require a redetermination of LG&E's capitalization after taking into consideration all adjustments to net operating income and revenue requirements?

A. Yes. Rates would have to be determined from a capital structure which has been adjusted to reflect <u>all</u> adjustments to operating revenues and expenses, including the increased revenue requirements. This approach would be equivalent to projecting total capitalization beyond the end of an historical test year, which the Commission does not allow. In fact, the Commission expressly rejected our proposal to extend capitalization beyond April 30, 1990, to reflect known and measurable costs associated with completion of the Trimble Generating Station.

Q. Are you recommending this methodology?

A. No. In order to be consistent with the "matching" principle set forth in the Rate Order, rates should be determined based on capitalization at the end of the test year. The adjustments to capitalization previously made for 25% of Trimble County not allowed in customer rates, unamortized retirements, and the capital costs of the LG&E building (because this adjustment was voluntarily made by the Company) are the only appropriate adjustments to capitalization.

Q. In his testimony, Mr. DeWard claims that in the absence of his proposed adjustment LG&E receives a windfall. Do you agree?

A. Absolutely not. Mr. DeWard does not seem to understand the difference between rate base and capitalization. The Commission's allowance of first year Trimble depreciation has absolutely no effect on capitalization. The additional revenue granted offsets the depreciation adjustment with no impact on capitalization. In addition, LG&E is not overcapitalized. Net original cost rate base exceeds capitalization, as determined in the Rate Order. See pages 11 and 15. The proposed adjustment would cause this difference to be even greater. Finally and most important, Mr. DeWard's proposed adjustment to capitalization is not proper because it is contrary to the Commission's policy regarding post test-year adjustments to capitalization.

Q. In prior rate orders, did the Commission adjust total capitalization to reflect a pro-forma adjustment to depreciation expense?

A. No. For example, in LG&E's previous rate case (Case No. 10064), the Commission allowed an increase in test-year depreciation expense of $1,871,837, but properly did not make a corresponding downward adjustment to capitalization. In its Order in Union Light, Heat, and Power's recent rate case (Case No. 90-041), the Commission made an adjustment to depreciation expenses but did not indicate that an adjustment to capitalization was made. To my knowledge, the Commission has never adjusted capitalization to reflect a pro-forma adjustment to depreciation expense.

Q. Should the Commission use rate base instead of total capitalization for setting rates?

A. Using ratebase is an option the Commission might want to consider. The use of total capitalization does cause some confusion. If property is excluded from rates, as in the case of 25% of Trimble County, it is abundantly clear what happens to rate base. However, it is not always clear by what amount capitalization should be reduced, because the net original cost of utility plant is booked as an asset not as capitalization. An example of the confusion that setting rates based on capitalization can cause is Mr. DeWard's contention early in the case, which he later retracted, that capitalization should be reduced by the cost of 25% of Trimble <u>plus</u> the investment tax credit attributable to this amount. Excluding 25% of the original cost of Trimble from capitalization may have also caused Mr. DeWard to jump to the erroneous conclusion that capitalization should be adjusted to reflect the depreciation expense.

STORM DAMAGE NORMALIZATION

Q. In his responsive testimony, Mr. Kinloch maintains that the calculation of average storm damage expenses for the 10-year period 1980-90 should exclude actual storm damage expenses incurred during July 1987. Do you agree with Mr. Kinloch's approach?

A. No. Mr. Kinloch has arbitrarily excluded storm damage expenses for the month of July 1987 because they were unusually high. Although expenses incurred during 1987 were high, that is no reason to exclude a portion of 1987 expenses in calculating an average. The purpose of calculating a 10-year average is to determine the expected value, based on all of the data, which then is used as a measure of the level of storm damage expenses on a going-forward basis. We believe that it would be highly unusual and inappropriate to arbitrarily remove some of the data because it is "too high". Mr. Kinloch has taken a very straightforward and <u>objective</u> calculation and turned it into a highly <u>subjective</u> measure of normal storm damage. Where would this end? Would it not be just as appropriate to exclude the years with the two lowest storm damage expenses because they are simply "too low"?

We repeat our assertion that Mr. Kinloch's exercise is analogous to calculating the average height of a basketball team without including the center's height in the calculation. Although well above the average, the height of a basketball center is a real, observable, and measurable occurrence. The analogies used by Mr. Kinloch, in contrast, have not been observed -- nor are they ever likely to be observed. It must be stressed that like the height of a basketball center, the amount of storm damage which LG&E incurred in 1987 was a real, observable, and measurable event. Neither the Commission nor the intervenors are in a position to guarantee that this level of storm damage will not reoccur in the future. Certainly, LG&E has an obligation to repair storm damage and restore service in an expedient manner without regard to the level of expense that might be incurred.

Q. The five year average storm damage expense calculated by the Company was $1,307,782. The Commission subsequently used a 10-year period to determine an inflation adjusted average of

$1,105,024. What were the actual storm damage expenses for 1990?

A. Actual storm damage expenses for the year ended December 31, 1990 were $1,673,760. This demonstrates that the use of a 5- or 10-year average is not unreasonable and that Mr. Kinloch's elimination of a portion of the 1987 storm damage expenses from the calculation of the average is unwarranted.

Q. Mr. Kinloch's rehearing testimony suggests that the Commission's use of a 5-year average in Case No. 10064 was designed to allow LG&E to recover the July 1987 storm damage expenses as a non-recurring expense item and that "by now, the July 1987 non-recurring costs have been recovered" by LG&E. Is that accurate?

A. No. In Case No. 10064, LG&E proposed a 3-year amortization of storm damage expenses, but the Commission decided instead to use a 5-year average to measure the level of expenses on a going-forward basis. In the Rate Order, the Commission used a 10-year average to measure the expected level of expenses on a going-forward basis. Mr. Kinloch seems to misunderstand the difference between the amortization of an investment or non-recurring expense (like downsizing) and the calculation of a normalization adjustment (like the storm damage adjustment) which attempts to measure <u>recurring</u> expenses on a going-forward basis.

Q. Does this conclude your testimony?

A. Yes.

Commonwealth of Kentucky

County of Jefferson

I, M. Lee Fowler, say that the statements contained in the foregoing testimony are true to the best of my knowledge and belief.

Dated this 6th day of March, 1991.

M Lee Fowler

SUBSCRIBED AND SWORN to before me by M. Lee Fowler on this 6th day of March, 1991.

Linda E Martin

Notary Public, State at Large, KY.
My commission expires May 12, 199[illegible]