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. 154

Responding Witness: William Steven Seelye

Q-154. With regard to Mr. Seelye's KU direct testimony, page 6, line 16 through page 7, line 1, please explain and provide all workpapers showing the method and basis for the decision to increase residential revenue by 4.27%, as well as to increase lighting rates by 4.22%.

A-154. KU is proposing to increase the two rate classes with rates of return significantly below the overall rate of return by approximately the same percentage. The workpapers are included 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. 155

Responding Witness: William Steven Seelye

Q-155. Please reference KU Seelye Exhibit 2. This exhibit references Seeley Exhibit 19 as the source. Please provide specific references to Seelye Exhibit 19 as to how (where) the following Residential amounts are developed or determined:

a. Distribution Customer Rate Base ($299,833,724);
b. Customer-related Expenses Before Adjustments ($66,877,997);
c. Incremental Income Taxes ($1,848,862); and,
d. Incremental Miscellaneous Revenues (-$193,043).

A-155. a. The Distribution Customer Rate Base amount of $299,833,724 contains an allocation of all rate base costs classified as customer related in Seelye Exhibit 18, the Functional Assignment and Classification section of the Cost of Service Study. The accumulation and subsequent allocation of these costs to each rate class can be found in the Rate Base section of the Cost of Service Study, Seelye Exhibit 19. These costs include the customer related portion of primary and secondary distribution related rate base, the customer related portion of distribution transformer rate base, distribution services, distribution meters, customer accounts rate base, and customer service rate base allocated to the residential class. The customer related portion of primary and secondary distribution rate base and distribution transformer rate base is determined through the application of the zero intercept for overhead conductor, underground conductor, and line transformers.

b. The Customer-Related Expenses Before Adjustments of $66,877,997 includes an allocation of all expenses classified as customer related in Seelye Exhibit 18, the Functional Assignment and Classification section of the Cost of Service Study. The expenses from Seelye Exhibit 18 are accumulated and allocated to each rate class in Seelye Exhibit 19. All categories of expenses are included in the calculation of customer-related expenses, including operation and maintenance (O&M), depreciation, regulatory credits, accretion, property and other taxes, amortization of investment tax credit, and other expenses. The components of expenses allocated to the residential class in each category that make up customer-related expenses include the customer related portion of primary and secondary distribution related O&M, the customer related portion of distribution transformer O&M, distribution service expenses, distribution meter expenses, customer accounts expenses, and customer service expenses.

c. The Incremental Income Taxes of $1,848,862 are the additional income taxes attributable to the increase in revenue associated with the proposed rate increase for the residential class allocated to the customer component based on rate base.

d. The Incremental Miscellaneous Revenue total of ($193,043) is an allocation of the incremental revenue associated with changing some of the miscellaneous charges. It was allocated to the residential customer component based on unadjusted expenses.

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. 156

Responding Witness: William Steven Seelye

Q-156. Please provide KU Seelye Exhibit 5 in executable Excel format.

A-156. 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. 157

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-157. Please provide KU adjusted test year General plant by FERC account and sub-account.

A-157. Please see the table below:

ACCOUNT	DESCRIPTION	TOTAL
138920	LAND	$ 2,581,972.75
139010	STRUCT AND IMPROV TO OWNED PROPERTY	29,901,858.58
139020	IMPROVEMENTS TO LEASED PROPERTY	531,973.44
139110	OFFICE EQUIPMENT	6,548,608.67
139120	NON PC COMPUTER EQUIPMENT	10,163,472.73
139130	CASH PROCESSING EQUIPMENT	448,190.94
139140	PERSONAL COMPUTER EQUIPMENT	2,486,305.62
139200	TRANSPORTATION EQUIPMENT	18,955,797.89
139300	STORES EQUIPMENT	735,053.44
139400	TOOLS, SHOP, AND GARAGE EQUIPMENT	5,473,498.11
139500	LABORATORY EQUIPMENT	3,160,382.43
139600	POWER OPERATED EQUIPMENT	270,941.73
139710	CARRIER COMMUNICATION EQUIPMENT	8,835,075.89
139720	REMOTE CONTROL COMMUNICATION EQUIP.	3,913,059.76
139730	MOBILE COMMUNICATION EQUIPMENT	4,987,845.78
139800	MISCELLANEOUS EQUIPMENT	373,590.26
	TOTAL GENERAL PLANT	$ 99,461,628.02

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. 158

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-158. Please provide KU adjusted test year CWIP in the greatest detail available. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-158. See attached for the total Company balances. The attachment is also provided on CD.

KU 107001 CWIP Balance
As of April 30, 2008

Description		Amount
GLENN LAKE ESTATES SUBDIVISION	$	43,054.40
NORTON STORM RESTORATION		5,843.92
PINEVILLE STORM RESTORATION		23,628.42
LONDON STORM RESTORATION		174,235.47
EARLINGTON STORM RESTORATION		150,540.56
DANVILLE STORM RESTORATION		53,970.88
ETOWN STORM RESTORATION		206,479.08
SHELBYVILLE STORM RESTORATION		148,236.91
MAYSVILLE STORM RESTORATION		70,440.45
LEXINGTON STORM RESTORATION		164,277.83
RICHMOND STORM RESTORATION		40,161.96
MISC SUBSTATION PROJECTS-KU		593,598.41
RICHMOND RD HIGHWAY RELOCATION		(135,460.51)
KY HWY 11 PHASE III RELOCATION		41,603.15
WIN: WINCHESTER BYPASS		13,378.50
HWY 52 RELOCATION RICHMOND		277,093.55
SANDERS THREE PHASE		(7,826.59)
KY HWY 19 RELOCATION		36,351.24
DISTRIBUTION LINE TRANSFORMERS		3,665,055.01
ARNLD-DRCHTR BLK MTN 161KV		24,341.26
LEX PARIS 12 KV HWY. REPL.		(294,476.60)
KY HWY. 11 PHASE 2 RELOC.		(21,489.98)
HAMBURG TOWNHOMES		9,194.88
DANVILLE OPERATIONS BLDG CAPITAL		6,526.00
REPL. 161KV REPL. COND.		79,970.84
ANDOVER DORCH. 34.5 HWY. REL.		148.96
GHENT KENTON 138KV HWY. RELOC.		(1.93)
CARROLLTON WARSAW 69KV		2,653.25
MISO DAY 2 IMPLEMENTATION PROJECT		22,891.70
SCIENCE HILL ENGINEERING		95,311.38
TATES CREEK RD HWY PROJ RIC		235,519.68
BALLARDSVILLE REGULATORS		9,517.55
KY 519 HIGHWAY RELOCATION		110,719.42
CONNORS STATION REGULATORS		19,169.75
UK CKT RELOCATION		60,439.50
PINEVILLE OPS. - KDL MAKE READY		(4,991.10)
HWY. RELOC. KY1577		189,563.55
WMB US25W HWY. WIDENING		37,549.92
HLN US421 BARN BR - VA LINE		75,480.07
SOMERSET NORTH TO STANFORD 69KV TAP TO FLOYD SUB		16,849.08
TC2 - KU		307,114,622.36
RELOC GRP - EARN 161 (HWY 431)		773.56
REPLACE H BUSHINGS ON G-062 (TY3)		24,885.30
WINCHESTER WATER WORKS		252,478.65
SPCC MODIFICATIONS FOR KU		668,977.38
BR3 TURBINE CNTL UPGR		763,947.29
TY ABATEMENT		31,442.35
ELIZABETHTOWN 3 ADDITION		3,662.56

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
RP RICHMAIND 3 4KV	562,583 45
REPLACE TAYLORSVILLE 5/7 MVA TRANSFORMER	707,545.03
SCM CENT SUB MISC WINCHESTER SOUTH 839 & AO SMITH 456	4,000 00
NESC FENCE REPLACEMENT	861.49
SCIENCE HILL HWY. 27	(560 22)
MISC. B&G FOR PINEVILLE AND LONDON	7,028 00
N US HWY 27	41,475.15
BOGGS LANE	185,147.24
LONDON CAPITAL FOR BUILDINGS	5,616.50
VIRGINIA CITY - CLINCH RIVER 138 KV	4,290,770.88
VIRGINIA CITY 138/69 KV TRANSFORMER ADDITION	1,743,710.37
DEVELOPMENT FOR TRIMBLE COUNTY UNIT # 2	28,224,089.03
KU SUBSTATION SPILL PREVENTION	3,518,549 01
GH3 FGD	1,499,055.36
977 HAVEN HILL RD	89,239.91
FUEL SUPPLY MANAGEMENT SYSTEM	858,518.21
KU SOX PROGRAM	2,450,026.27
PURCHASE LAND FOR A NEW BEDFORD, KENTUCKY SUBSTATION	358,096.44
GREENBURG HWY PROJECT LONGMEADOW	3,563 94
GHENT 1 CONTROLS MODERNIZATION	5,187,628.84
GHENT 2 CONTROLS MODERNIZATION	1,580,289.05
GHENT 3 CONTROLS MODERNIZATION	5,669,651.98
GHENT 4 CONTROLS MODERNIZATION	3,972,711.65
LOUDON AVE WINCHESTER 69KV	32,799.89
KU DIST. 34.5 KV STORM	30,735.10
KU TRANS 34.5 KV STORM	33,742.98
BROWN ASH POND EXPANSION, PHASE 1 - DEVELOPMENT STAGE	34,932,432.85
KU SOX PROGRAM - GHENT 2 FGD SYSTEM	67,760,632 40
DANVILLE HILLSIDE COLLAPSE	(10,640.29)
INVALID INDIRECT 122 PROJECT	(980.10)
BEDFORD TAP 69KV	79,954.78
LAWRENCEBURG PRIORITY 2 POLE REPLACEMENT	304,725.38
GR FUEL OIL TANK REPL.	808,627.28
PURCHASE PMI POWER METERS	10,155.25
PURCHASE SPARE BREAKER & SWITCH 34.5K SYSTEM	40,800.28
ELIHU TO STANFORD 69KV HWY RELOCATION PHASE 2	(3,298 42)
GH4 FGD	148,513,480.69
GHENT SO2 COMMON	134,772,107.78
BROWN 1, 2, 3 FGD	140,537,197.04
BR1 CONTROLS UPGR	2,517,013.91
BR 2-3 CO MONITOR UPGR	69,421.89
BR1-2 TURB VI MON UPGR	224,308.01
BR COMPUTER EQUIPMENT	6,415.30
GR ASBESTOS ABATEMENT	20,987.86
KU MOBILE COMPUTING	16,533.82
GHENT SCR	2,513,169.98
GH1 REHEAT OUTLET HEADER REPLACEMENT	993,616.17
GH4 UNDER TURBINE FIRE PROTECTION	389,358.25

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
SCM PINEVILLE NESC VIOLATIONS	42,628.01
GH1 GENERATOR REFURB	11,574,683.26
PINE-HUTCH PHASE II RECONDUCTOR	75,853.64
GH SO3 ENGINEERING STUDY	108,582.50
INST LEBANON JUNCTION SUB	1,812,414.46
RP SHUN PIKE TRANSFORMER	575,836.06
ROGERS GAP DISTRIBUTION	406,447.08
W360 LTC REBUILD	1,483,468.12
STATION PIKE REBUILD	206,772.38
MAYOC BLDG AND GROUNDS	6,635.54
KENTON - CARNTOWN 69 HWY	7,831.50
MISC. A/R UNCOLLECTIBLE - KU CAPITAL	24,501.00
RICHMOND BUILDING MISC	8,534.00
MISCELLANEOUS CAPITAL FOR BUILDINGS - LEXINGTON	74,585.29
KU WORST CIRCUITS CIRCUIT HARDENING	776,503.45
INTERACTIVE VOICE RESPONSE IVR ENHANCEMENTS	37,505.62
DELVINTA 824 CARRIER ADDN	109,269.56
ARNOLD 804 CARRIER ADDN	79,957.17
CONVERT CRAB ORCHARD SUB 775-1 FROM 4KV TO 12.4KV	895.18
HW/SW DEV TOOLS 026560	30.57
HW/SW DEV TOOLS 026560	30.33
HW/SW DEV TOOLS 026570	30.33
EAST KY SONET FIBER BACKBONE ROUTE	779,145.83
EXTEND FIBER TO GREEN RIVER	135,528.94
UPGRADE LEXINGTON MAN TO OC-48 USING NEXT GENERATION SONET	303,830.99
(LIVE COMMUNICATION SERVER) NEW TECHNOLOGY PILOT	16,308.16
WESTERN KY MICROWAVE A/D CONVERSION & RE-CONFIG-PHASE 2	465,233.36
LOUDON AVE TO LANSDOWN 69KV DOUBLE CIRCUIT RE-BUILD	3,996,517.18
TURBO BALANCER FOR PLANTS	4,787.45
FAWKES 138-69KV, 150 MVA	1,314,380.72
DETROIT HARVESTER SECTION OF PARIS-LEX. PLANT	173,045.71
LAKE REBA - WACO 69KV LINE	15,465.00
AO SMITH EWINGTO 59 kv	22,360.61
SMT KY DOT 8-259.10 SOM SW BY PASS	16,351.62
INVALID GEN. ENGR. LOC. ENGR.	(0.96)
CONTROL CENTER FACILITIES	7,883,573.27
BROWN - FAWKES 138KV	281,065.11
161 KV INTERCONNECTION WITH ESTILL COUNTY ENERGY PARTNERS	50,181.93
CT 11N2 VANE REPL	1,524,046.02
SOMERSET COLLEGE STREET U/G & O/H	(108,586.40)
KU DIST PF CORRECTION	247,659.57
ETOWN 634 REPLACE	(15.67)
LEX PLANT 644 REPLACE	50,103.44
LOUDON AVE 628 REPLACE	70,779.81
OHIO CO BATTERY REPLACEMENT	16,261.02
WHEATCROFT BATTERY REPLACEMENT	16,857.44
HARDIN CO BATTERY REPLACEMENT	18,742.74
CARROLTON BATTERY REPLACEMENT	19,528.06

KU 107001 CWIP Balance

As of April 30, 2008

Description	Amount
COMPUTER PURCHASES KU	15,644.95
INST ELK CRK MINE 69 TAP	105,619.18
PAYNES DEPOT RD (US 62) HIGHWAY	168,505.44
PURCHASE 161X69 SPARE TRANSFORMER	693,042.99
KU SUBS RTU INSTLLS FOR EKPC METERING	134,273.50
RICHMOND 604 TERMINAL LIMITS	12,986.68
GR BOILER 4 PENTHOUSE INSULATION	29,730.02
KU PRIMEDIA COURSE MANAGEMENT SYSTEM UPGRADE	2,425.65
SHELBYVILLE BYPASS	(13,044.02)
WAITSBORO TAP 69KV SOUTHWEST BYPASS RELOCATION	43,215.33
HWY REL US27 / KY1247 / KY90	54,188.95
SMT PULASKI LIBRARY	718.49
WEST LEXINGTON RTU REPLACEMENT	18,002.28
TOOL AND/OR EQUIPMENT KU FACILITIES MAINTENANCE	10,324.00
KU CARPET AND TILE REPLACEMENT	145,396.52
REVISED FIRE PROTECTION SYSTEM EQUIPMENT - ONE QUALITY	92,903.00
EAST FRANKFORT RTU REPLACEMENT	40,696.65
REPLACE BARDSTOWN 138KV PT'S	24,624.31
PISGAH RTU REPLACEMENT	21,305.10
GRAHAMVILLE RTU REPLACEMENT	27,131.36
FIRE PROTECTION SYSTEM EQUIPMENT - KU DIX DAM	66,025.06
TRIMBLE COUNTY ASH/GYPSUM PONDS	573,333.47
TC2 AQCS KU	91,448,226.13
GR PRECIPITATOR CONTROLS UPGRADE	146,761.17
FARLEY REPLACE FENCE	24,475.80
WESTFRANFORT RTU REPLACEMENT	30,073.27
AVON TAP 69KV RELOCATION	2,537.22
KU STORM	51,319.37
UNION UNDERWEAR NEW TRANSFORMER ADDITION IN SUB 642	45,753.01
SCM EARLINGTON WILDLIFE PROTECTION	9,767.67
SCM EARL PURCHASE ELECTRONIC RECLOSERS	18,795.73
NESC CORRECTIONS	73,302.69
SCM EARL SUBSTATION REP (PURCHASE S&C FUSES)	296,432.25
SCM EARL TOOLS AND EQUIP	12,538.40
SCM WILDLIFE PROTECTION PINEVILLE	10,611.61
SCM PINE REPLACE FENCES	13,486.21
SCM PINEVILLE NESC VIOLATIONS	20,375.84
SCM RP FAILED BREAKERS PINEVILLE SUB	41,519.90
SCM PINEVILLE SUB MISC	76,912.38
PURCHASES TOOLS & EQUIPMENT PINEVILLE	9,707.57
DISTRIBUTION OPERATIONS REPORTING - KU	22,474.73
DISTRIBUTION OPERATIONS SOFTWARE LICENSES	11,384.19
SYNERGEE ELECTRIC RELIABILITY	31,388.57
WMS 3.6.2 STORMS UPGRADE - KU	47,099.54
KU IMPLEMENT GIS REDLINING	103,690.21
KU DOIT MOB COMP FOR GIS	140,149.99
MOBILE COMPUTING INFRASTRUCTURE	190,683.88
PC INFRASTRUCTURE - KU	170,545.92

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
OMS UPGRADE	101,399.87
HOPEWELL CIRCUIT #0286 REGULATION	37,396.92
DANVILLE CARPET AND CEILING TILE REPLACEMENT	2,140.00
ELIZABETHTOWN CARD READER ENTRY (2 BACK DOORS)	12,439.20
LONDON SAFETY WALLS AND DOORS	18,040.80
CARPET AND TILE REPLACEMENT	4,503.31
E-TOWN MINI SPLIT HEAT PUMP	10,900.00
RICHMOND CARDREADERS	4,207.43
SHELBYVILLE SECURITY WALL	21,814.61
BARLOW CARD READER	10,662.55
BARLOW FENCING	6,053.00
EARLINGTON CARD READERS	8,129.27
GREENVILLE DRAINAGE	9,750.00
LONDON CARD READER	8,846.72
KU ANALOG TO DIGITAL	45,006.34
METERSHOP TOOLS	8,027.60
E WORKSTATIONS MODULE UPGRADE - KU	9,005.50
KU ERTS	70,277.80
PC PURCHASES	58,372.91
KU BUSINESS OFFICE AUTO RECIEPT PROJECT	885.00
PURCHASE PROPERTY FOR INNOVATION DRIVE SUBSTATION #428-1	1,621,594.95
SCM PURCHASE REGULATORS	24,832.40
SUBSTATION BATTERIES FOR CENTRAL SUBSTATION DEPT	33,336.60
SCM REPLACE BUSHING	10,671.67
SCM 7.5MVA PORT XFRM	16,379.04
SCM REPLACE BREAKERS	143,318.78
SCM SUBSTATION MISC	106,294.53
PURCHASE OF PUMP TRAILERS FOR MAINTENANCE	53,227.57
AUTOMATIC GATE AT DANVILLE SCM	30,908.92
AUTOMATIC GATE AT LEXINGTON SCM	50,248.51
SCM RANSFORMER REWINDERS	229,669.48
MAYOC INV TOOLS	3,271.59
MAYOC BLDG & GROUNDS	9,358.63
BROWN NORTH TRANSFER TRIP RECEIVER REPLACEMENT	11,348.24
NEW DOUBLE CKT TO CITATION BLVD	19,380.42
AWARE BOILER TUBE SOFTWARE	95,536.04
PLANT LAB EQUIPMENT UPGRADES	22,065.75
GHENT-DUKE ENERGY BLACKWELL SUBSTATION INTERCONNECTION	11.72
LOUDON AVE - WINCHESTER 69 KV REBUILD	354,250.55
REEL WIRE TRAILERS	14,382.81
BR CT UNDERGROUND PIPE SPCC (DEV)	13,278.35
CT6 A/B CONVERSION	6,186,526.42
DEVELOPMENT TY OIL CONTAIN SPCC	19,772.15
DEVELOPMENT HF OIL CONTAIN SPCC	18,396.03
TY3 5-1 EL CONV	128,243.87
TY3 ABATEMENT	28,576.22
TY MISC MOTOR RBIDS	29,132.18
UNDERGROUND FOR THE UK CHANDLER MEDICAL CENTER	4,851,439.51

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
GHENT-KENTON 138 KV LINE - P2 POLE REPLACEMENT	732,251.15
BR1 COOLING TWR RBLD	1,110,925.10
BR1 CONTROL AIR COMP REPL	104,765.80
BR1 TURBINE SEALS	214,638.07
BR2 RH INLET & OUTLET HDR	328,803.82
BR1-1 SBAC REPLACEMENT	2,194.07
BR CONVEYOR BELT REPL	28,731.60
BR1 DEMIN RETIREMENT	1,098.20
BR CONV GEARBOX REPL	46,716.00
BR1 SPARE 2.3KV BRK	70,010.35
REVISED 2.3KV BREAKER RECOND	96,039.37
BR SODIUM ANALYZER REPL	52,862.12
BR PHOS PUMP REPL	6,102.14
DX OIL SEPARATOR SEPARTOR SPCC	11,732.37
DX1 OVERHAUL	29,193.73
DX3 JOHNSON VIV REFURB	842,093.55
LANCASTER SUB EKP 69KV TIE	(1,364.16)
LAKE REBA RTU REPLACEMENT	37,749.69
GH4 CT CELL 4-5 REBUILD	248,273.15
GH CONVEYOR BELT REPL	136,039.05
GH2 AUX COND 2-2 RETUBE	116,112.82
REVISED GH4 ECONOMIZER REPLACEMENT	2,891,859.86
GHENT SPCC COMPLIANCE MODIFICATIONS	276,369.28
DAVIESS CO 345kv TIE	0.01
GHENT - KENTON 138 KV LINE - BUTLER SWITCHES	178,609.99
MILLERSBURG CONTROL HSE REPL	43,242.26
ETOWN 614 UPGRADE	13,476.70
TY3 ABATEMENT	24,384.94
KU STORM SPARE	78,891.90
LOUDON STORAGE LOT & FENCE REPAIR	50,790.59
BROWN C.T. BARDSTOWN 138KV LINE POLE REPLACEMENT	37,475.67
REMOVE AND REPLACE FAILED BREAKER AT WEST CLIFF 624	854.91
LON FAWN VALLEY ESTATES SUBDIVISION U.G. SYSTEM	127,522.80
OCEDA MT. EDEN PARKWAY 600 AMP 3 PHASE	48,669.13
SECOND DATA CENTER	3,080,692.05
SO3 SORBENT INJECTION	6,463,278.76
RP 69/34 TRANSF DORCHESTER	428,692.79
ADD REGULATORS AT ANDOVER	148,702.64
CYNTHIANS INTERCONNECTION ON ADAMS TO MILLERSBURG	33,022.64
NORTH AMERICAN STAINLESS 345-138 KV450 MVA TRANSFORMER	3,641,671.95
HARDWARE / SOFTWARE DEVELOPMENT TOOLS	4,229.06
GHENT 345KV BREAKER ADDITION	371,113.88
HARDWARE / SOFTWARE DEVELOPMENT TOOLS	23,616.44
HARDWARE ENERGY MARKETING	8,807.82
ITSD HARDWARE / SOFTWARE ENERGY MARKETING	438.75
ITSD HARDWARE / SOFTWARE POWER GENERATION KU	3,013.56
HW/SW DEV TOOLS	4,224.45
HW/SW DEV TOOLS	5,980.63

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
HW/SW DEV TOOLS	4,744 87
HARDWARE / SOFTWARE DEVELOPMENT TOOLS	6,215 93
MONITOR REPLACEMENT - KU	42,155 29
TIER C ROTATION OF DESKTOPS AND LAPTOPS-KU	308,890 16
VISTA IE 7 & OFFICE PROJECT	35,759 67
RACKS AND FURNITURE	38,871 99
BULK POWER AND ENVIRONMENTAL SYSTEMS- KU	47,030 66
LAND MOBILE RADIO SYSTEM BUILDOUT	1,883,694 24
NETWORK ACCESS DEVICES AND SITE INFRASTRUCTURE - KU	32,126 96
MILL CREEK - HARDIN COUNTY OPGW	47,460 19
OUTSIDE CABLE PLANT - KU	91,006 95
TELEPHONE SYSTEMS CAPACITY EXPANSION - KU	49,551 91
WESTERN KENTUCKY SONET RING UPGRADE TO OC-48	468,765 63
SERVER REPLACEMENT - KU	452,710 89
SAN REPORTING TOOL	95,264 27
BACKUP STRATEGY EXPANSION PROJECT - KU	121,223 43
IP KVMS EXPANSION - KU	36,787 65
CABLING AND SERVER CONNECTIVITY	13,061 99
CORE NETWORK INFRASTRUCTURE	113,934 53
SECURITY INFRASTRUCTURE ENHANCEMENTS	25,461 89
VPN & WIRELESS BUILDOUT	36,705 01
NETWORK MANAGEMENT SYSTEM	45,469 86
DATA NETWORKS TEST TOOLS	20,386 75
SERRUS II - KU	32,006 54
KU - CERUS II	129,430 77
DATA NETWORKS ACCESS DEVICES & GATEWAYS - KU	39,464 38
IT STRATEGY & PLANNING 07 RESEARCH TECH INVEST	40,117 40
IT SECURITY MONITORING AND AUDIT MGMT TOOLS	46,949 81
IT SECURITY INFRASTRUCTURE PKI	67,328 89
UNION UNDERWEAR CIRCUIT WORK	190,562 71
RELIEVE LOAD PARKERS MILL SUB 2	75,180 04
MODIFY EXISTING CRANE ON SERVICE DOCK	2,606 28
NAS TAP 345KV LINE	1,207,329 93
CONSTRUCT LEBANON EAST SUB	679,248 28
KY RVR PUMP SUBSTATION #710-2	372,930 76
ADD TRANSF UNION UNDERWEAR	627,168 89
ALEXANDER #402-1 SUBSTATION	90,326 70
DIAMOND SUB TRANSF	53,420 71
EL SUB ABB TRANSF REPL	291,042 27
BR3 ROOF VENT FAN REPL	117,091 10
KU RISS BACKUP	30,441 44
RELOC KU HWY 286 PROJ	(4,676 33)
ORACLE FINANCIAL/MATERIAL APPLICATIONS 11 5 10 2 UPGRADE	204,879 81
POWERPLANT SOFTWARE IMPLEMENTATION	698,098 58
FORKLIFT FOR KU STOREROOM	19,716 00
TAYLOR CO TRANSFORMER	183,753 45
KU RTU PURCHASE	119,717 69
DIST CAPACITORS KU	367,887 06

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
SAP FOR CCS - KU	10,701,899.09
NEW BASE GENERATING UNIT - KU	(33.94)
HIGBY MILL - FAWKES 69KV EKPC - SOUTHPOINT INTERCONNECTION	41,132.76
WILSON DOWNING TAP (69KV) SWITCH AND RECONFIGURATION	93,463.73
REPLACE FAILED HARLAN Y TRANSFORMER	242,556.36
BR1 SAS BURNER DIFF TRIAL	16,611.77
SHARE POINT KU	14,926.72
TC CT UNIT COMPRESSOR BLADE REPLACEMENTS	201,352.03
GHENT ASH POND/LANDFILL	535,881.87
BARCODE SCANNER REPLACEMENT	25,461.12
GREEN RIVER CONTROL LAN PATCH/ANTIVIRUS SERVER	3,399.56
LEBANON BYPASS	68,818.70
COLUMBIA BYPASS	7,140.55
RELOC RING RD PROJ (345KV)	269,917.12
REPL. SUBSTATION BATTERIES	74,834.43
MERCURY MONITORING KU	48,078.42
GH 2B AUXILIARY TRANSFORMER	292,925.23
LIBERTY ROAD RELOCATION BRYANT ROAD TAP	79,160.40
RELOC HARDIN CO - BONVILLE 69KV	125,526.01
BEREA BYPASS	(28,614.29)
DUNCANNON ROAD HIGHWAY RELOCATIONS	250,070.32
LEMONS MILL #723	1,215,007.35
MOBILE RADIO	4,154.79
EW BROWN HIGBY MILL DC 138KV RELOCATION	34,700.00
DIX FEP EXPANSION	77,824.65
REVISED BR2 TURBINE BLADES	105,500.00
MAIS II SERVER	17,472.36
TC CT DISCONNECT SWITCH DRIVE UPGRADE	8,816.88
SECOND FIBER TO BOC DATA CENTER	58,086.19
BUS LOAD DATA	21,698.55
MOVE OPENJAVA OFF HIS SERVER	8,660.99
EMS SOFTWARE UPGRADE IMPLEMENTATION	54,675.81
NORTH KY BACKBONE RENOVATION	56,952.59
NERC BACKUP CONTROL CENTER COMPLIANCE COMMUNICATIONS	76,406.40
LEXINGTON AREA IMPROVEMENTS	108,407.11
DEVELOPMENT DX CRANE ACCESS ROAD	29,190.00
WITNESS UNCOUPLING	2,670.21
UMS GROUP INVESTMENT EVALUATION MODEL	175,674.01
KU STORMS	37,376.54
TAYLOR COUNTY RTU REPLACEMENT	23,707.30
HDSBG-ADD 69KV BKRS FOR CUST	96,183.52
PLACE 1000 MCM COPPER ALONG WALNUT ST IN DANVILLE	(5,146.27)
STELLENT JOURNAL ENTRY IMAGING	4,146.95
GH4 PM MONITOR	71,935.20
DANVILLE HVAC	14,394.00
ORACLE ISUPPORT PORTAL	133,919.73
CCS - KU BUSINESS INTELLIGENCE	292,521.61
CCS - CHANGE MGMT KU	185,305.84

KU 107001 CWIP Balance

As of April 30, 2008

Description	Amount
CCS - CUSTOMER SERVICE KU	2,526,853.70
CCS - DEVELOPMENT KU	684,033.32
CCS - TECHNOLOGY KU	3,978,828.21
TY3 SAMPLE CHILLER REPL	5,589.34
BR1 1-3 MILL MOTOR REFURB	22,706.52
REPLACE FAILED WEST CLIFF TRANSFORMER T-477	86,961.39
GR SECOND BELT MAGNET	20,137.39
STATION BATTERY REPLACEMENT	64,212.82
U3 DCS UPGRADE	87,699.60
TMIS REPLACEMENT PROJECT	17,733.03
SUSE LINUX IMPLEMENTATION	39,842.97
PC PURCHASES RETAIL OPERATIONS SERVICES	451.28
KU CARPET & TILE REPLACEMENT	5,541.88
KU INTERNAL REQUESTS	868.81
SPARE TRANSF	722,556.60
ADD TRANSF HORSE CAVE INDUSTRIAL	915,006.42
CITY OF BARDSTOWN SUB	675,261.36
HORSE CAVE INDUSTRIAL SUBSTATION DISTR WORK	159,631.80
SCM EARL GREEN RIVER PLT XFMR	34,392.59
REPLACE TRANSFORMER AT KY STATE HOSPITAL SUBSTATION #587	3,542.81
CKT 412 RECONDUCTOR 2/0 TO 795	66,252.13
SC&M WILDLIFE PROTECTION PINEVILLE	11,058.65
SCM PINEVILLE SUB MISC	4,905.89
GH BY PRODUCT LOADING FACILITY	186.60
WINDSTREAM POLE REPLACEMENT	3,407.87
HORSECAVE NEW TRANSFORMER IN SUB	29,840.42
RICHMOND #069-6 BREAKER ADDITION	6,807.50
REPLACE TRANSFORMER 7/14 WOODLAWN	1,719.98
SERENA DIMENSIONS CM SOFTWARE IMPLEMENTATION	69,062.28
TY3 RECORDER REPL	4,676.36
KU SOFTWARE LICENSES	621.34
KU PC & PRINTER INFRASTRUCTURE	47,309.61
SCM REP REWIND	48,525.38
KU STORM	4,530.99
KU STORM	20,559.59
IN 10 MVA BASE (14) LTC TRANSFORMER & ASSOC EQUIP	(705,369.95)
VIDEO WALL RELOCATION (INSTALLATION)	10,212.49
KU ERT'S	99,185.93
HORSE CAVE RECONDUCTORING	165,066.24
KU STORMS	39,932.54
REVISED RECONDUCTOR 2/0 TO 397 MCM HORSE CAVE CIRCUIT 2432	60,475.99
CMDB AUTO UPDATE - KU	25,921.28
TY 5-4 EL MILL CONV	134,639.09
INST ARMSTRONG COAL 69 TAP	(23,415.79)
BR3 CONTROL AIR RECEIVER	8,249.68
BR LASER ALIGNMENT	46,391.56
BR VEHICLE PURCHASE	6,659.48
GR BOILER #5 SPARE MILL MOTOR	30,277.36

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
GDS IMPLEMENTATION - KU	8,945 08
NAS NETWORK ATTACHED STORAGE	103,333 23
UK HOSPITAL DISTRIBUTION RELOCATION UG	190,372.44
GH1 CT CELL 1-1 REBUILD	383,903 88
GH4 GENERATOR REWEDGE	236,752 25
GH 4 4-2 CCW HEAT EXCHANGER	152,478 77
UK MED. CTR. CONTROL HOUSE RELOC	33,803 38
TC CT LUBE OIL VARNISH SYSTEM	30,840 70
KU STORM WORK	112,547 94
PLACE OVERHEAD & UNDERGROUND FEEDER TO BRUSS INDUTRIES	44,941.28
BR1-1 SWP REBUILD	152,914 33
LYNCH TO POCKET 69KV HOLMES MILL	272,547 95
EVA REPLICATION - KU	95,536 38
LEBANON EAST SUBSTATION	92,850 25
GR TRANSFORMER REMOVAL & SALVAGE	527 12
UK FIBER RELOCATION	6,972 65
U3 DCS PROCESSOR UPGRADE	53,350 55
BLADELOGIC IMPLEMENTATION - KU	178,477.27
BR 1-3 PULVERIZER GEARBOX REBUILD	262,230 83
NMARKET - PJM IMPLEMENTATION	133,334 76
TRANSMISSION LAPTOPS	3,042.31
TECHNOLOGY ROOM	3,820 09
HWSW DEVELOPMENT TOOLS - KU	217 46
IT TOOLS ENERGY SERVICES MRMD - KU	665 91
HARDWARE & SOFTWARE TOOLS IT SERVCO - KU	1,678 42
HW/SW DEV TOOLS	64 37
HW/SW DEV TOOLS	1,990 20
HW/SW DEV TOOLS	442 95
MONITOR REPLACEMENT KU	533 23
TIER C REPLACEMENT KU	91,835 81
LOUISVILLE ELECTRICAL UPGRADE	3,206 93
AVAYA UPGRADES REMOTE KU SYSTEMS	1,743.61
BULK POWER & ENVIRONMENTAL SYSTEMS - KU	3,625 44
DEVELOP KU CAMPUS NETWORK	2,734 69
MOBILE RADIO - KU	5,280 84
NETWORK ACCESS DEVICES & INFRASTRUCTURE - KU	13,093 88
NETWORK TOOLS & TEST EQUIPMENT - KU	7,235 36
OUTSIDE CABLE PLANT - KU	867 98
TELEPHONE SYSTEMS CAPACITY EXPANSION	2,835 14
CABLING FOR SERVER CONNECTIVITY	5,378 60
SERVER HARDWARE REFRESH	21,788 25
ACCESS SWITCH ROTATION	119,897 09
CORE NETWORK INFRASTRUCTURE	4,495 50
NETWORK MANAGEMENT - KU	5,993 27
SECURITY INFRASTRUCTURE ENHANCEMENTS- KU	1,533 74
IT SECURITY INFRASTRUCTURE PKI	1,452 32
E.W BROWN UNIT 3 SCR CONCEPTUAL ENGINEERING	660,912 89
MOBILE GIS LICENSES	138,096 80

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
BR1 MILL MOTOR REFURB	10,202 76
BR1 1-1 MILL MOTOR REFURB	19,007.13
SOMERSET SOUTH MAIN ST STREETSCAPE	(12,656 57)
GARRARD COUNTY HIGH SCHOOL	136,123.46
CROCKET TO GARDNER 69KV ALEX CREEK EKPC TAP	90,463.00
STORAGE NETWORK EXPANSION - KU	136,033.90
INSTALL NEW 795 CIRCUIT TO NESTLE PLAN 2	300,162.93
BR1 GENERATOR FLUX PROBE INSTALL	11,542 06
BR WAREHOUSE SWEEPER	12,636.79
EWINGTON #539 BREAKER ADDITION	58,068.71
VERSAILLES DRIVE THRU WINDOW	4,452.50
BR MEDIA PROJECTOR	5,257.04
LOUDEN AVENUE HAEFLING 138KV HWY RELOC	828.91
CORNING MOTORIZED 69KV 2 WAY 1200 AMP	37,648.92
BARDSTOWN INDUSTRIAL	76,512.41
BLUECOAT APPLIANCES	41,804.94
SECURITY SYSTEMS FOR VARIOUS KU STOREROOM	38,926.68
ORACLE IPROCUREMENT PUNCHOUT XML PRO CARD	17,106.91
GH 1G TRANSFORMER	56,330.24
SULFUR CHN ANALYZER REPLACEMENTS	47,761 00
LOAD FORECAST FILE STORAGE	1,663.83
BRYANT RD 69 KV TAP	26,018.95
CONSTRUCT NEW CKT FROM	141,048.83
TY3 TURB RM SUMP REPL	9,223.16
GR 2004 FORD F250 PICK UP	12,992.33
INST RIVER VIEW MINE 69 TAP	66,593.99
BUSINESS OFFICE SECURITY CAMERA	45,588.07
BRYANT ROAD #3 SUBSTATION & TEMP TRANSF	49,019.88
BRYANT ROAD #3 EXIT CIRCUIT	33,334 43
BOC LL TRAINING ROOM G & F - KU	5,952.24
REPLACE HVAC UNIT MAPPING SECTION	8,534.00
INNOVATION DRIVE SUBSTATION 138KV TAP	775.33
STORMS	835,206.52
BR3 COOLING TOWER STORM DAMAGE REPAIRS	812,724.66
TY3 COLLECTOR RNG RP	470.82
ELECTRIC ENCHANCE OH DISTRIBUTION	(90,419.83)
WINTER STORM	368,751.81
STORMS	27,132.13
PEOPLESOFT SELF SERVICE EMPLOYEE GIVIING	30,244.42
OSI ENERGY MGMT SYSTEM EMS FEP DB POINT EXP. KU	13,703.25
MOBILE SUPPLY CHAIN EXPANSION - KU	8,917.04
BR3 WEST ROLLING DOOR	116 66
KU ODP STORM	44,812.44
NEW ANALOG BACKUP RTU	1,575.79
BR "G" CONVEYOR GEAR REDUCER	9,950.41
MOTOR REPLACE LGE - CORPORATE	73,733.74
BR2-5 COOLING TOWER MOTOR REWIND	795.74
NLDG AND GROUNDS 216	14,009.72

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
BEHIND THE METER 156	5,923.56
BEHIND THE METER 216	(26,154.07)
BEHIND THE METER RC 236	426.28
BEHIND THE METER 256	(3,354.40)
BEHIND THE METER 315	3,167.20
INVALID INDIRECT RC013660	226.32
BEHIND THE METER RC 426	4,253.29
Inst cap/reg/recl-Earlington	43,748.55
Instl cap/reg/recl-Danville	106,099.36
Inst cap/reg/recl-Richmond	96,555.85
Inst cap/reg/recl-Etown	119,076.42
Inst cap/reg/recl-Shelbyville	187,575.80
Inst cap/reg/recl-Lexington	486,848.84
Inst cap/reg/recl-Maysville	178,131.46
Inst cap/reg/recl-Pineville	47,535.29
Instl cap/reg/recl-London	41,196.84
Inst cap/reg/recl-Norton	(7,658.75)
Fuse Coord-Earlington	73,193.83
Fuse Coord-Danville	17,117.51
Fuse Coor-Richmond	78,318.94
Fuse Coord-Etown	366.95
Fuse Coord-Shelbyville	7,077.37
Fuse Coord-Pineville	32,216.89
Fuse Coord-London	572.01
CIS DATA	(101,286.36)
RELOCATIONS TRANS LINES	(296,784.98)
NEW FACILITIES TRANS LINE PWO	157,326.19
PARAMETER UPGRADE T LINE PWO	363,538.10
XMFR/CUTOUT/DISC-DIST	5,334.96
STORM DAMAGE T-LINE PWO	934,555.76
PRIORITY REPL T-LINES PWO	2,660,093.53
LINE LOCATION RC156	23,987.74
LINE LOCATING 014160	(267.73)
CAP/REG/RECL. RC156	58,824.89
CAPL REGUL./RECL. 216	8,688.14
CAP/REG/RECL 012360	26,528.31
CAP/REG/RECL - 01246	9,455.86
CAP. REG. & RECLOSERS 012560	5,511.21
CAPACITORS/REGULATORS/RECLOSERS 366	24,586.73
CAP/REG/RECL 366	52,862.17
CAP/REG/RECL 416	5,305.27
CAP/REG/RECL RC 014260	7,084.54
CAP/REG/RECL. RC766	2,611.03
PURCHASE OF METERS 315	6,970.10
PURCHASE OF METERS	590,177.84
NEW BUSINESS COM 156	(21,085.24)
New Bus Comm-Ovhd-Earlington	1,275,360.47
New Bus Comm-UG-Earlington	259,512.88

KU 107001 CWIP Balance

As of April 30, 2008

Description	Amount
NEW BUSINESS COM 166	(26,010 74)
NEW BUSINESS COM 216	228,950 79
New Bus Comm-Ovhd-Danville	1,284,955 57
New Bus Comm-UG-Danville	718,381 97
NEW BUSINESS COM 236	(270,989 45)
New Bus Comm-Ovhd-Richmond	132,309 86
New Bus Comm-UG-Richmond	72,962.93
NEW BUSINESS COM 246	(59,504 09)
New Bus Comm-Ovhd-Etown	1,069,307 61
New Bus Comm-UG-Etown	486,964 65
NEW BUSINESS COM 256	(313,224 93)
New Bus Comm-Ovhd-Shelbyvl	179,610 10
New Bus Comm-UG-Shelbyville	122,039 01
NEW BUSINESS COM 315	(18,811.00)
New Bus Comm-Ovhd-Lexington	439,960 31
New Bus Comm-UG-Lexington	617,176 92
NEW BUSINESS COM 366	(203 20)
New Bus Comm-Ovhd-Maysville	126,990 33
New Bus Comm-UG-Maysville	114,644 78
NEW BUSINESS COM 416	(157,077 19)
New Bus Comm-Ovhd-Pineville	49,255 35
New Bus Comm-UG-Pineville	7,446 11
NEW BUSINESS COM 426	251,122 56
New Bus Comm-Ovhd-London	92,996 14
New Bus Comm-UG-London	133,925 99
NEW BUSINESS COM 766	1,063 40
New Bus Comm-Ovhd-Norton	137,388 55
New Bus Comm-UG-Norton	31,552 52
NEW BUSINESS IND 156	1,678 11
New Bus Ind-Ovhd-Earlington	64,022 79
New Bus Ind-UG-Earlington	704 55
NEW BUSINESS IND 216	141,526 50
New Bus Ind-Ovhd-Danville	423,017 78
New Bus Ind-UG-Danville	229,303 67
New Bus Ind-Ovhd-Richmond	2,454 83
New Bus Ind-UG-Richmond	4,365.03
New Bus Ind-Ovhd-Etown	118,005 64
New Bus Ind-UG-Etown	239,590 46
New Bus Ind-Ovhd-Shelbyvl	137,767 88
New Bus Ind-UG-Shelbyville	31,168 07
New Bus Ind-Ovhd-Lexington	83,794 22
New Bus Ind-UG-Lexington	34,671 29
New Bus Ind-Ovhd-Maysville	941 25
New Bus Ind-Ovhd-Pineville	484 65
NEW BUSINESS IND 426	8,712 03
New Bus Ind-Ovhd-London	97,811 54
New Bus Ind-UG-London	36,497 21
New Bus Ind-UG-Norton	198 94

KU 107001 CWIP Balance

As of April 30, 2008

Description	Amount
NEW BUSINESS MINE POWER 156	53.87
NEW BUSINESS MINE POWER 416	12,329.62
NEW BUSINESS MINE POWER 426	7,071.34
NEW BUSINESS MINE POWER 766	39,005.80
NEW BUSINESS RES 156	83,195.77
New Bus Resid-Ovhd-Earlington	2,543,016.46
New Bus Resid-UG-Earlington	812,092.70
NEW BUSINESS RES 166	(45,063.38)
NEW BUSINESS RES 216	448,946.09
New Bus Resid-Ovhd-Danville	135,995.98
New Bus Resid-UG-Danville	54,973.58
NEW BUSINESS RES 236	(262,129.74)
New Bus Resid-Ovhd-Richmond	106,701.35
New Bus Resid-UG-Richmond	81,323.21
NEW BUSINESS RES 246	(2,290.87)
New Bus Resid-Ovhd-Etown	49,543.20
New Bus Resid-UG-Etown	18,309.11
NEW BUSINES RES 256	(682,832.01)
New Bus Resid-Ovhd-Shelbyvl	61,154.16
New Bus Resid-UG-Shelbyville	56,921.11
NEW BUSINESS RES 315	(157,504.68)
New Bus Resid-Ovhd-Lexington	386,704.32
New Bus Resid-UG-Lexington	3,914,649.01
NEW BUSINESS RES 336	(2,731.00)
NEW BUSINESS RES 366	(6,397.20)
New Bus Resid-Ovhd-Maysville	113,661.45
New Bus Resid-UG-Maysville	94,458.84
NEW BUSINESS RES 416	17,406.33
New Bus Resid-Ovhd-Pineville	174,562.95
New Bus Resid-UG-Pineville	24,158.20
NEW BUSINESS RES 426	238,478.25
New Bus Resid-Ovhd-London	140,246.75
New Bus Resid-UG-London	87,290.22
NEW BUSINESS RES 766	93,258.72
New Bus Resid-Ovhd-Norton	1,854,143.80
New Bus Resid-UG-Norton	98,415.28
New Bus Subd-Ovhd-Earlington	77,169.12
New Bus Subd-UG-Earlington	165,561.28
New Bus Subd-Ovhd-Danville	115,493.96
New Bus Subd-UG-Danville	452,552.52
New Bus Subd-Ovhd-Richmond	5,319.22
New Bus Subd-UG-Richmond	72,947.89
New Bus Subd-Ovhd-Etown	55,326.96
New Bus Subd-UG-Etown	18,462.23
New Bus Subd-Ovhd-Shelbyvl	4,855.36
New Bus Subd-UG-Shelbyville	51,694.09
New Bus Subd-Ovhd-Lexington	88,602.42
New Bus Subd-UG-Lexington	201,300.48

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
NEW BUSINESS SUBDIV U/G MAYSVILLE	66,758.26
New Bus Subd-Ovhd-Pineville	4,233 62
New Bus Subd-UG-Pineville	109,987 47
New Bus Subd-Ovhd-London	10,559.73
New Bus Subd-UG-London	130,703 66
New Bus Subd-Ovhd-Norton	13,919 31
New Bus Subd-UG-Norton	41,736.46
New Elect Serv-Ovhd-Earlington	1,675,602 75
New Bus Serv-UG-Earlington	1,557,125 53
New Elect Serv-Ovhd-Danville	1,075,325 33
New Bus Serv-UG-Danville	1,489,590 81
New Electric Serv-Overhead	1,155,732 55
New Bus Serv-UG-Richmond	2,127,216 22
New Elect Services-Overhead	1,633,525.38
New Bus Serv-UG-Etown	1,903,404 14
New Elect Serv-Ovhd-Shelbyvl	785,899 75
New Bus Serv-UG-Shelbyville	1,306,496 15
New Elect Serv-Ovhd-Lexington	2,373,274 44
New Bus Serv-UG-Lexington	7,110,183.17
New Elect Serv-Ovhd-Maysville	1,099,813 31
New Bus Serv-UG-Maysville	1,662,474 97
New Elect Serv-Ovhd-Pineville	1,037,225 81
New Bus Serv-UG-Pineville	455.645 15
New Elect Serv-Ovhd-London	579,973 70
New Bus Serv-UG-London	873,596 85
New Elect Serv-Ovhd-Norton	1,113,248 77
New Bus Serv-UG-Norton	769,559 25
NON REG. REL. INSP. RC156	5,826 44
NON-REG REL. INSP. 017660	238 01
Pub Wrk Reloc-OH-Earlington	4,229 65
Pub Wrk Reloc-OH-Danville	307,081 92
Pub Wrk Reloc-UG-Danville	(10,200.24)
Pub Works Relc-OH-Richmond	143,048 91
Pub Wrk Reloc-UG-Richmond	6,158 43
Pub Wrk Relc-OH-Etown	423,179.64
Pub Wrk Reloc-UG-Etown	2,510.41
Pub Wrk Reloc-OH-Shelbyvl	116,072 94
Pub Wrk Reloc-UG-Shelbyville	1,435 76
Pub Wrk Reloc-OH-Lexington	795,172 59
Pub Wrk Reloc-UG-Lexington	34,558.64
Pub Wrk Reloc-OH-Maysville	90,472.24
Pub Wrk Reloc-OH-Pineville	43,978 14
Pub Wrk Reloc-OH-London	215,897.32
Pub Wrk Reloc-UG-London	38,714.61
Pub Wrk Reloc-OH-Norton	109,752.23
Pub Wrk Reloc-UG-Norton	(6,074 74)
POLE TREAT 216	1,987 71
POLE TREAT 236	70.57

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
OUTDOOR LIGHTING 156	517,585.28
OUTDOOR LIGHTING 216	649,552.58
OUTDOOR LIGHTING 236	328,752.46
OUTDOOR LIGHTING 246	288,396.37
OUTDOOR LIGHTING 256	177,789.34
OUTDOOR LIGHTING 315	2,493,102.00
OUTDOOR LIGHTING 366	205,104.42
OUTDOOR LIGHTING 416	270,452.79
OUTDOOR LIGHTING 426	351,956.87
OUTDOOR LIGHTING 766	304,499.82
RELOCATIONS CUST REQUEST 156	(321.15)
RELOCATIONS CUST REQUEST 216	11,033.11
RELOCATIONS CUST REQUEST 236	134,471.64
RELOCATIONS CUST REQUEST 246	(21,353.96)
RELOCATIONS CUST REQUEST 256	34,733.26
RELOCATIONS CUST REQUEST 315	432,438.90
RELOCATIONS CUST REQUEST 366	46,900.12
RELOCATIONS CUST REQUEST 416	309,230.92
RELOCATIONS CUST REQUEST 426	215,568.71
RELOCATIONS CUST REQUEST 766	196,714.62
REP./REPL. DEFECTIVE EQUIP RC011019	293,229.06
OAKHILL SUB. BATTERY REPL.	243,742.90
DAMAGE DEFECTIVE DIST 156	19,664.52
Rep Def Equip-OH-Earlington	1,567,129.80
Rep Def Equip-UG-Earlington	59,668.24
Rep Def Equip-UG-Greenville	865.80
DAMAGE DEFECTIVE DIST 216	47,789.60
Rep Def Equip-OH-Danville	678,695.23
Rep Def Equip-UG-Danville	39,525.70
DAMAGE DEFECTIVE DIST 236	13,045.53
Rep Def Equip-OH-Richmond	619,070.36
Rep Def Equip-UG-Richmond	113,523.93
Rep Def Equip-OH-Etown	295,104.79
Rep Def Equip-UG-Etown	16,433.86
Rep Def Equip-OH-Shelbyvl	691,832.01
Rep Def Equip-UG-Shelbyville	87,080.67
DAMAGE DEFECTIVE DIST 315	60,231.04
Rep Def Equip-OH-Lexington	1,887,470.91
Rep Def Equip-UG-Lexington	917,337.90
DAMAGE DEFECTIVE DIST 366	2,189.05
Rep Def Equip-OH-Maysville	358,678.73
Rep Def Equip-UG-Maysville	92,449.10
Rep Def Equip-OH-Pineville	191,957.55
DAMAGE DEFECTIVE DIST 426	(562.00)
Rep Def Equip-OH-London	355,688.09
Rep Def Equip-UG-London	22,295.84
DAMAGE DEFECTIVE DIST 766	12,925.60
Rep Def Equip-OH-Norton	181,793.65

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
Rep Def Equip-UG-Norton	5,629.02
POINTS OF INTEREST EARLINGTON	71,862.47
POINTS OF INTEREST - DANVILLE	21,793.59
POINTS OF INTEREST - RICHMOND	1,696.85
POINTS OF INTEREST SHELBY	27,009.47
POINTS OF INTEREST LEXINGTON	7,629.69
POINTS OF INTEREST MAYSVILLE	18,038.16
POINTS OF INTEREST PINEVILLE	18.12
POINTS OF INTEREST LONDON	7,114.92
REP/REPL DEF POL'S 156	162,381.06
REP/REPL DEF POL'S 216	145,192.42
REP/REP DEF POL'S	123,006.13
REP/REPL DEF POL'S	51,345.34
REP/REPL DEF POL'S 256	223,069.58
REP/REPL DEF POL'S 315	183,366.79
REP/REPL DEF POL'S 366	61,576.94
REP/REPL DEF POL'S 416	98,974.53
REP/REPL DEF POL'S 426	225,069.53
REP/REPL DEF POL'S 766	39,695.93
POLE REP./ REPL 156	743,171.04
POLE REPAIR 216	189,175.41
POLE REPAIR 236	218,780.20
POLE REPAIR/REPL. 246	892,788.21
POLE REPAIR/REPL. 256	662,919.30
POLE REPAIR REPL. 315	604,253.84
POLE REPAIR/REPL. 366	464,114.63
POLE REPAIR 416	282,732.64
POLE REP./REPL. 426	347,472.10
POLE REP./REPL. 766	185,634.58
REP REPL DEF ST LIGHTS 156	468,701.45
REP REPL DEF ST LIGHTS 216	274,118.21
REP REPL DEF ST LIGHTS 236	440,390.19
REP REPL DEF ST LIGHTS 246	311,540.73
REP REPL DEF ST LIGHTS 256	292,978.37
REP REPL ST LIGHTS 315	529,441.75
REP REPL DEF ST LIGHTS 366	327,262.37
REP REPL DEF ST LIGHTS 416	82,443.68
REP REPL DEF ST LIGHTS 426	157,781.31
REP REPL DEF ST LIGHTS 766	58,002.84
KU GENERAL RELIABILITY	66,683.70
DIST RELIABILITY 156	537,323.76
RELIABILITY O/H 156	379,647.65
RELIABILITY AND RECONST UG RC156	5,144.51
DIST RELIABILITY 216	31,160.00
RELIABILITY RECONSTRUCTION 216 OH	189,605.18
CIRCUIT HARD REL. U/G 216	6,238.29
DIST RELIABILITY 236	72,178.67
RELIABILITY RECONSTRUCTION 236 OH	102,760.22

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
CIRCUIT HARD RELIABILITY UG 236	27,548.46
DIST RELIABILITY 246	166,660.62
RELIABILITY RECONSTRUCTION 246 OH	36,032.62
RELIABILITY O/H 256	276,242.87
CIRCUIT HARD RELIABILITY UG - RC 012560	11,033.45
DIST RELIABILITY 315	9,265.96
CIRCUIT RELIAB. O/H 315	634,781.71
RELIABILITY U/G 315	52,183.54
RELIABILITY RECONSTRUCTION 366 OH	259,035.68
DIST RELIABILITY 416	124,285.68
RELIABILITY RECONSTRUCTION 416 OH	139,439.18
DIST RELIABILITY 426	23,087.93
RELIABILITY AND RECONST. OH RC426	60,693.10
CIRCUIT HARD RELIABILITY UG 426	68.12
DIST RELIABILITY 766	2,034.23
CIRCUIT HARD REL OH NORTON	205,386.51
CIRCUIT HARD RELIABILITY UG RC766	509.37
REP THRD PARTY DAM 156	97,219.21
REP THRD PARTY DAM 166	3,804.47
REP THRD PARTY DAM 216	257,793.94
REP THRD PRTY DAM 236	419,094.32
REP THRD PARTY DAM 246	101,237.84
REP THRD PARTY DAM 256	284,031.55
REP THRD PARTY DAM 315	937,907.42
REP THRD PARTY DAM 366	324,310.64
REP THRD PARTY DAM 416	5,563.27
REP THRD PARTY DAM 426	69,194.93
REP THRD PARTY DAM 766	37,837.48
RES INVEST TROUBLE 256	458.03
STREET LIGHTING 156	655,755.24
STREET LIGHTING 216	951,580.35
STREET LIGHTING 236	1,539,138.91
STREET LIGHTING 246	913,071.57
STREET LIGHTING 256	560,109.66
STREET LIGHTING 315	4,098,354.47
STREET LIGHTING 336	(7,141.80)
STREET LIGHTING 366	956,354.67
STREET LIGHTING 416	498,752.55
STREET LIGHTING 426	572,135.91
STREET LIGHTING 766	443,538.07
SWITCHING TD - 156	8,504.54
SWITCHING T/D 012160	14,123.68
SWITCHING T/D RC416	5,429.42
SWITCHING T/D 766	4,220.53
Sys Enhanc-Exist Cust-Earlngtn	528,591.15
Sys Enhanc-Exist Cust-Greenvl	148.17
Sys Enhan-Exist Cust-Danville	383,444.00
Sys Enh-New Cust-Richmond	308,261.02

KU 107001 CWIP Balance
As of April 30, 2008

Description	Amount
Sys Enh-Exist Cust-Etown	446,315.87
Sys Enhanc-Exist Cust-Shelbyvl	267,171.05
Sys Enhan-Exist Cust-Lex	47,272.82
Sys Enhan-Exist Cust-Maysville	276,361.70
Sys Enhan-Exist Cust-Pineville	323,801.66
Sys Enhan-Exist Cust-London	347,251.23
Sys Enhan-Exist Cust-Norton	166,171.29
TROUBLE ORDER OH - 156	8,088.33
TROUBLE ORDERS UG - RC 011560	911.24
TROUBLE ORDERS OH 216	31,451.50
TROUBLE ORDERS UG - 012160	711.94
TROUBLE ORDERS O/H 236	9,565.83
TROUBLE ORDERS O/H 246	559,660.28
TROUBLE ORDERS UG 246	1,916.99
TROUBLE ORDERS O/H 256	434,951.77
TROUBLE ORDER U/G 256	31,739.32
TROUBLE ORDERS O/H 315	15,505.23
TROUBLE ORDERS UG	315.15
TROUBLE ORDERS O/H 416	111,141.67
TROUBLE ORDERS OVERHEAD	389,781.19
TROUBLE ORDERS UG RC426	15,255.52
TROUBLE ORDERS O/H 766	81,803.21
TROUBLE ORDERS UG 766	6,782.25
TOOLS AND EQ 156	130,633.12
TOOLS AND EQ 216	70,369.27
TOOLS AND EQ 236	17,508.69
TOOLS AND EQ 246	244,531.89
TOOLS AND EQ 256	206,366.72
TOOLS AND EQ 315	160,345.53
TOOLS AND EQ 366	8,231.19
TOOLS AND EQ 416	14,572.21
TOOLS AND EQ 426	5,870.37
TOOLS AND EQ 766	28,811.30
TROUBLE ORDERS 156	543,550.34
TROUBLE ORDERS 216	334,535.66
TROUBLE ORDERS 236	134,135.52
TROUBLE ORDERS 256	3,208.19
TROUBLE ORDERS 308	134,605.09
TROUBLE ORDERS 315	181,462.32
TROUBLE ORDERS 366	74,818.98
CIS INTERFACE	(1,130.32)
PURCHASE TRANSFORMERS 156	147,073.03
PURCHASE TRANSFORMERS 216	143,925.51
PURCHASE TRANSFORMERS 236	641,776.20
PURCHASE TRANSFORMER 246	315,280.38
PURCHASE TRANSFORMERS 256	318,503.95
PURCHASE TRANSFORMER 315	979,370.91
PURCHASE TRANSFORMERS 366	328,831.87

KU 107001 CWIP Balance
As of April 30, 2008

Description		Amount
PURCHASE TRANSFORMERS 416		77,064.63
PURCHASE TRANSFORMER 426		90,503.58
PURCHASE TRANSFORMERS 766		172,992.18
	$	1,234,053,513.38

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. 159

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-159. Please provide KU adjusted test year depreciation reserve and depreciation expense by FERC account.

A-159. See attached for total Company balances.

ACCOUNT	DESCRIPTION	ACCUMULATED DEPRECIATION	DEPRECIATION EXPENSE
PRODUCTION PLANT			
STEAM PLANT			
131100	STRUCTURES AND IMPROVEMENTS	(128,533,209.89)	
131200	BOILER PLANT EQUIPMENT	(585,990.634.90)	
131400	TURBOGENERATOR UNITS	(143.728,351.99)	
131500	ACCESSORY ELECTRIC EQUIPMENT	(67,672,517.72)	
131600	MISCELLANEOUS POWER PLANT EQUIPMENT	(13.628,863.73)	
131700	ASSET RETIREMENT OBLIGATION - STEAM	(4.421,157.78)	
	TOTAL STEAM PRODUCTION PLANT	$ (943,974,736.01)	$ 49,562,469.82
HYDRAULIC PLANT			
OTHER THAN PROJECT PLANT			
133010	LAND RIGHTS	(924,422.62)	
133100	STRUCTURES AND IMPROVEMENTS	(323,990.67)	
133200	RESERVOIRS, DAMS AND WATERWAYS	(6,569.778.89)	
133300	WATERWHEELS, TURBINES AND GENERATORS	(302,274.52)	
133400	ACCESSORY ELECTRIC EQUIPMENT	(78,698.28)	
133500	MISCELLANEOUS POWER PLANT EQUIPMENT	(41,606.98)	
133600	ROADS, RAILROADS AND BRIDGES	(49.385.91)	
133700	ASSET RETIREMENT OBLIGATION - HYDRAULIC	(1,777.32)	
	TOTAL HYDRAULIC PLANT- OTHER THAN PROJECT PLANT	(8,291,935.19)	
	TOTAL HYDRAULIC PRODUCTION PLANT	$ (8,291,935.19)	$ 174,096.42
PRODUCTION PLANT			
OTHER PRODUCTION PLANT			
134010	LAND RIGHTS	(79,671.69)	
134100	STRUCTURES AND IMPROVEMENTS	(8,837,666.93)	
134200	FUEL HOLDERS, PRODUCERS AND ACCESS	(6,725,953.79)	
134300	PRIME MOVERS	(77,016,150.10)	
134400	GENERATORS	(19,840,348.74)	
134500	ACCESSORY ELECTRIC EQUIPMENT	(8,091,762.44)	
134600	MISC POWER PLANT EQUIPMENT	(1,534,837.49)	
134700	ASSET RETIREMENT OBLIGATION - OTHER PRODUCTION	(30,480.13)	
	TOTAL OTHER PRODUCTION PLANT	$ (122,156,871.31)	$ 16,624,788.28

ACCOUNT	DESCRIPTION	ACCUMULATED DEPRECIATION	DEPRECIATION EXPENSE
TRANSMISSION PLANT			
OTHER THAN PROJECT PLANT			
135010	LAND RIGHTS	(15,467,621.39)	
135210	STRUCT & IMPROVE-NON SYS CONTROL/COM	(4,071,013.12)	
135220	STRUCT & IMPROVE-SYS CONTROL/COM	(812,094.66)	
135310	STATION EQUIPMENT-NON SYS CONTROL/COM	(63,950,575.35)	
135320	STATION EQUIPMENT-SYS CONTROL/COM	(17,231,697.12)	
135400	TOWERS AND FIXTURES	(45,450,816.31)	
135500	POLES AND FIXTURES	(69,454,666.56)	
135600	OVERHEAD CONDUCTORS AND DEVICES	(105,538,675.65)	
135700	UNDERGROUND CONDUIT	(146,621.79)	
135800	UNDERGROUND CONDUCTORS AND DEVICES	(855,049.09)	
135910	ASSET RETIREMENT OBLIGATION - TRANSMISSION	(4,074.55)	
	TOTAL TRANSMISSION PLANT- OTHER THAN PROJECT PLANT	(322,982,905.59)	
	TOTAL TRANSMISSION PLANT	$ (322,982,905.59)	$ 15,501,826.82
DISTRIBUTION PLANT			
PROJECT PLANT			
136010	LAND RIGHTS	(3.73)	
136400	POLES, TOWERS AND FIXTURES	(1,588.22)	
136500	OVERHEAD CONDUCTORS AND DEVICES	3,460.92	
	TOTAL DISTRIBUTION-PROJECT PLANT	1,868.97	
DISTRIBUTION PLANT			
OTHER THAN PROJECT PLANT			
136010	LAND RIGHTS	(1,044,779.28)	
136100	STRUCTURES AND IMPROVEMENTS	(1,578,113.22)	
136200	STATION EQUIPMENT	(33,140,360.25)	
136400	POLES, TOWERS AND FIXTURES	(118,109,042.66)	
136500	OVERHEAD CONDUCTORS AND DEVICES	(112,751,809.77)	
136600	UNDERGROUND CONDUIT	(572,287.39)	
136700	UNDERGROUND CONDUCTORS AND DEVICES	(21,704,224.48)	
136800	LINE TRANSFORMERS	(93,659,592.84)	
136900	SERVICES	(57,186,308.81)	
137000	METERS	(28,835,511.49)	
137100	INSTALLATIONS ON CUSTOMERS' PREMISES	(15,576,105.09)	
137300	STREET LIGHTING AND SIGNAL SYSTEMS	(26,565,470.39)	
137400	ASSET RETIREMENT COST - DISTRIBUTION	(6,655.99)	
	TOTAL DISTRIBUTION PLANT- OTHER THAN PROJECT PLANT	(510,730,261.66)	
	TOTAL DISTRIBUTION PLANT	$ (510,728,392.69)	$ 32,312,375.70

ACCOUNT	DESCRIPTION	ACCUMULATED DEPRECIATION	DEPRECIATION EXPENSE
GENERAL PLANT			
139010	STRUCT AND IMPROV TO OWNED PROPERTY	(8,182,873 33)	
139020	IMPROVEMENTS TO LEASED PROPERTY	(382,294 62)	
139110	OFFICE EQUIPMENT	(3.237.399 60)	
139120	NON PC COMPUTER EQUIPMENT	(7.325,709 89)	
139130	CASH PROCESSING EQUIPMENT	(260,804 79)	
139140	PERSONAL COMPUTER EQUIPMENT	(1,820,099 04)	
139200	TRANSPORTATION EQUIPMENT	(18,848,158 14)	
139300	STORES EQUIPMENT	(309,142 05)	
139400	TOOLS, SHOP, AND GARAGE EQUIPMENT	(1,682,577 28)	
139500	LABORATORY EQUIPMENT	(1,695,542 72)	
139600	POWER OPERATED EQUIPMENT	(110,356 15)	
139710	CARRIER COMMUNICATION EQUIPMENT	(2,046,162 67)	
139720	REMOTE CONTROL COMMUNICATION EQUIP	(1,834,495 06)	
139730	MOBILE COMMUNICATION EQUIPMENT	(2,152,666 35)	
139800	MISCELLANEOUS EQUIPMENT	(265,787.60)	
	TOTAL GENERAL PLANT	(50,166,959.17)	4,987,606.48
	GRAND TOTAL	$ (1,958,301,799.96)	$ 119,163,163.52 [1]

NOTE 1: EXPENSE IS NOT TRACKED SEPARATELY BY PLANT ACCOUNT

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. 160

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-160. Please provide all KU calculated, known, or estimated uncollectible expense by customer class.

A-160. This information is not available. The Company does not maintain uncollectible expense by customer class.

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. 161

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-161. Please provide KU customer deposits by class as of 4/30/2008.

A-161. Please see the response to Question No. 164.

Account Type	Deposit Amount
Residential	$8,164,031.84
Commercial	8,515,801.55
Industrial	2,011,643.64
Mine Power	262,533.84
Street Lighting	540.00
Other Public Authorities	74,623.23
Municipal Pumping	425.00
Miscellaneous	3,945.58
TOTALS	$19,033,544.68

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. 162

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-162. Please provide KU interest on customer deposits by class.

A-162. The Company does not maintain interest on customer deposits separately by class. See the response to Question No. 164.

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. 163

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-163. Please provide actual and estimated KU meter reads by class during the test year.

A-163. The following information represents the total actual and estimated meter reads. The Company does not maintain meter reads by class separately.

Actual Meter Reads	6,423,909
Estimated Meter Reads	83,385

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. 164

Responding Witness: William Steven Seelye

Q-164. Please explain how and where customer deposits and/or interest on customer deposits are reflected in the KU class cost of service study.

A-164. Consistent with the Commission's Order in Case No. 98-474 (KU) and Case No. 98-426 (LG&E) interest expenses on deposits are not included as a component of revenue requirement and customer deposits are not deducted from rate base or capitalization. Consequently, neither customer deposits nor interest on customer deposits are considered 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. 165

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-165. Please provide the following by month for the period January 2003 through July 2008 by rate schedule for KU:

a. customers billed; and,
b. billed KWH (as applicable).
Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-165. a. See attached for customers billed from April 2006 through July 2008. Prior to April 2006, the Company did not maintain this level of detail.

b. See attached.

Kentucky Utilities Company
Case No. 2008-00251
Customers Billed by Rate Schedule
For the Period April 2006 through July 2008

Customers	Jul-2008	Jun-2008	May-2008	Apr-2008	Mar-2008	Feb-2008	Jan-2008	Dec-2007	Nov-2007	Oct-2007	Sep-2007
Residential Service RS	414,820	413,439	413,670	413,545	414,349	414,460	415,859	413,688	412,958	412,803	412,010
Volunteer Fire Dept Service VFD	31	31	31	31	30	30	30	30	30	30	30
General Service GS	79,201	79,090	78,970	78,831	78,808	78,668	78,724	78,419	78,309	78,395	78,091
All Electric School AES	297	297	299	313	312	310	311	309	307	307	302
Street Lighting Service STL	1,524	1,520	1,519	1,517	1,516	1,516	1,519	1,519	1,523	1,522	1,536
Private Outdoor Lighting POL	63,322	63,222	63,143	63,144	63,194	63,179	63,340	63,129	63,016	62,887	62,803
Large Power Service LP	8,948	8,963	8,980	9,035	9,067	9,127	9,209	9,190	9,233	9,310	9,330
Large Comm/Ind Time-of-Day Svc LCI-TOD	49	45	47	48	47	45	47	46	45	46	44
Small Time-of-Day Service STOD	53	53	53	53	53	53	53	53	53	53	53
Coal Mining Power Service MP	44	44	40	42	41	41	44	38	46	41	40
Large Mine Power Time-of-Day LMP-TOD	11	7	9	9	9	10	10	10	7	11	11
Net Metering Service - GS	2	2	2	2	2	2	2	2	2	2	1
Net Metering Service - RS	4	4	4	4	4	4	3	3	3	3	2
Special Contracts	-	-	-	-	-	-	-	-	9	9	9
Large Industrial Time-of-Day Svc LITOD	1	1	1	1	1	1	1	1	1	1	1
Curtailable Service Rider 1 - PRIM (A)	1	1	1	1	1	1	1	1	1	1	1
Curtailable Service Rider 3 - TRANS (A)	1	1	1	1	1	1	1	1	1	1	1
Redundant Capacity RC	4	4	2	3	2	2	2	2	2	2	2
TOTAL	568,313	566,724	566,772	566,579	567,436	567,451	569,154	566,441	565,545	565,424	564,268

Kentucky Utilities Company
Case No. 2008-00251
Customers Billed by Rate Schedule
For the Period April 2006 through July 2008

Customers	Aug-2007	Jul-2007	Jun-2007	May-2007	Apr-2007	Mar-2007	Feb-2007	Jan-2007	Dec-2006	Nov-2006	Oct-2006
Residential Service RS	412,293	412,533	411,243	411,481	411,476	412,046	411,030	412,564	410,809	408,868	409,022
Volunteer Fire Dept Service VFD	30	30	30	29	30	30	30	30	30	30	30
General Service GS	77,832	77,892	77,689	77,420	77,258	77,089	76,924	76,906	76,512	76,218	76,163
All Electric School AES	303	300	306	305	306	305	303	308	307	303	297
Street Lighting Service STL	1,555	1,541	1,537	1,535	1,542	1,588	1,528	1,528	1,535	1,532	1,542
Private Outdoor Lighting POL	62,793	62,834	62,729	62,668	62,573	68,271	62,438	62,495	62,304	62,069	61,914
Large Power Service LP	9,381	9,417	9,501	9,546	9,594	9,646	9,703	9,792	9,816	9,830	9,970
Large Comm/Ind Time-of-Day Svc LCI-TOD	46	43	44	44	43	43	43	43	43	43	44
Small Time-of-Day Service STOD	53	54	52	53	53	53	53	53	53	53	53
Coal Mining Power Service MP	37	40	39	39	42	41	43	44	42	41	43
Large Mine Power Time-of-Day LMP-TOD	11	11	11	11	11	11	11	11	9	9	8
Net Metering Service - GS	1	1	1	1	1	1	1	1	1	1	2
Net Metering Service - RS	1	-	-	-	-	-	-	-	-	-	-
Special Contracts	9	9	9	9	9	15	9	9	9	7	7
Large Industrial Time-of-Day Svc LITOD	1	1	1	1	1	1	1	1	1	1	1
Curtailable Service Rider 1 - PRIM (A)	1	1	1	1	1	1	1	1	1	1	1
Curtailable Service Rider 3 - TRANS (A)	1	1	1	1	1	1	1	1	1	1	1
Redundant Capacity RC	2	2	2	2	2	2	2	2	2	1	1
TOTAL	564,351	564,710	563,197	563,148	562,943	569,144	562,120	563,789	561,474	559,009	559,101

Kentucky Utilities Company
Case No. 2008-00251
Customers Billed by Rate Schedule
For the Period April 2006 through July 2008

Customers	Sep-2006	Aug-2006	Jul-2006	Jun-2006	May-2006	Apr-2006					
Residential Service RS	408,756	407,442	408,146	407,948	407,846	406,645					
Volunteer Fire Dept Service VFD	30	30	30	30	30	30	This information is not available prior to April 2006.				
General Service GS	75,972	75,647	75,558	75,344	75,135	74,931					
All Electric School AES	303	336	295	299	303	303					
Street Lighting Service STL	1,531	1,528	1,526	1,529	1,525	1,525					
Private Outdoor Lighting POL	61,857	61,714	61,760	61,817	61,685	61,574					
Large Power Service LP	9,905	10,046	10,168	10,223	10,287	10,341					
Large Comm/Ind Time-of-Day Svc LCI-TOD	41	42	42	42	42	42					
Small Time-of-Day Service STOD	53	53	53	53	53	53					
Coal Mining Power Service MP	41	44	42	40	41	39					
Large Mine Power Time-of-Day LMP-TOD	9	7	8	6	7	7					
Net Metering Service - GS	1	1	1	1	1	1					
Net Metering Service - RS	-	-	-	-	-	-					
Special Contracts	4	4	4	4	5	5					
Large Industrial Time-of-Day Svc LITOD	1	1	1	1	1	1					
Curtailable Service Rider 1 - PRIM (A)	1	1	1	1	1	1					
Curtailable Service Rider 3 - TRANS (A)	1	1	1	1	1	1					
Redundant Capacity RC	1	-	-	1	1	-					
TOTAL	558,509	556,896	557,636	557,339	556,964	555,499					

Kentucky Utilities Company
Case No. 2008-00251
Billed KWH by Rate Schedule
For the Period January 2003 through July 2008

KWH	Jul-2008	Jun-2008	May-2008	Apr-2008	Mar-2008	Feb-2008	Jan-2008	Dec-2007	Nov-2007
Residential Service RS	536,565,907	429,850,541	344,921,715	448,696,845	617,456,820	696,166,352	725,065,419	556,880,721	399,622,238
Volunteer Fire Dept Service VFD	43,102	36,087	31,098	40,963	59,353	72,748	80,486	59,156	37,491
General Service GS	169,452,592	147,815,982	129,218,753	140,865,011	159,685,395	170,394,166	176,580,937	148,134,180	130,321,549
All Electric School AES	8,064,173	8,912,615	9,035,484	10,274,632	12,588,858	13,539,936	13,794,988	11,838,410	9,617,758
Street Lighting Service STL	3,134,916	2,945,075	3,218,195	3,449,894	3,972,304	3,937,330	4,659,311	4,756,109	4,420,481
Private Outdoor Lighting POL	5,428,717	5,098,923	5,535,034	5,956,440	6,924,112	6,803,388	8,039,322	8,243,354	7,617,298
Large Power Service LP	483,358,882	447,132,366	410,936,995	405,752,429	412,827,201	426,427,282	445,667,993	415,956,284	414,800,044
Large Comm/Ind Time-of-Day Svc LCI-TOD	315,430,361	299,298,180	291,207,805	296,102,364	291,651,543	284,162,964	294,752,382	283,623,477	271,417,633
Small Time-of-Day Service STOD	18,607,084	7,241,224	15,423,356	15,515,960	14,675,044	14,888,388	17,371,444	16,151,948	16,086,536
Coal Mining Power Service MP	14,595,343	17,326,764	15,379,591	16,496,241	16,539,371	17,363,913	16,814,441	14,690,848	14,310,065
Large Mine Power Time-of-Day LMP-TOD	34,131,600	26,982,156	29,312,400	30,217,800	29,396,400	31,257,600	34,529,400	30,020,400	29,323,747
Net Metering Service - GS	1,103	526	302	377	897	716	900	877	475
Net Metering Service - RS	6,904	5,376	4,112	5,574	7,190	8,283	6,533	4,233	2,335
Special Contracts	-	-	-	-	-	-	-	-	2,000
Curtailable Service Rider 1 - PP	-	-	-	-	-	-	-	-	-
Large Industrial Time-of-Day Svc LITOD	29,233,440	36,642,240	36,296,640	42,206,400	36,402,480	35,955,360	33,538,320	35,069,760	29,300,400
TOTAL	1,618,054,124	1,429,288,055	1,290,521,480	1,415,580,930	1,602,186,968	1,700,978,426	1,770,901,876	1,525,429,757	1,326,880,050

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KWH	Jan-2007	Dec-2006	Nov-2006	Oct-2006	Sep-2006	Aug-2006	Jul-2006	Jun-2006	May-2006
Residential Service RS	607,641,581	431,795,560	555,600,411	357,164,254	480,237,820	599,200,906	533,859,602	430,375,088	345,244,435
Volunteer Fire Dept Service VFD	62,413	38,788	57,230	25,230	34,764	39,588	35,285	30,937	26,352
General Service GS	149,275,210	123,408,895	138,640,058	122,075,446	143,772,457	155,536,855	145,000,281	130,150,247	114,787,881
All Electric School AES	11,519,286	9,260,569	11,121,400	8,977,184	10,718,229	9,517,764	7,988,726	8,146,273	8,901,688
Street Lighting Service STL	4,623,359	4,385,967	4,721,348	4,184,234	3,655,828	3,388,428	3,088,310	2,905,837	3,168,526
Private Outdoor Lighting POL	7,951,979	7,479,680	8,096,658	7,078,887	6,215,492	5,748,688	5,283,315	4,966,606	5,411,735
Large Power Service LP	442,166,378	419,428,676	431,535,052	447,002,344	506,725,020	520,163,978	504,253,042	484,034,793	451,091,912
Large Comm/Ind Time-of-Day Svc LCI-TOD	285,306,902	282,660,403	281,305,677	306,371,225	315,346,781	308,270,484	307,188,257	302,231,540	265,420,538
Small Time-of-Day Service STOD	16,694,276	15,936,160	16,197,216	16,942,604	18,869,984	20,181,864	19,466,852	17,986,060	16,950,860
Coal Mining Power Service MP	17,197,900	18,867,400	19,066,400	18,826,100	17,453,972	20,669,328	17,256,869	21,090,517	22,811,774
Large Mine Power Time-of-Day LMP-TOD	32,147,771	27,705,338	30,541,697	23,603,035	26,078,292	21,618,000	19,230,000	20,264,400	20,948,400
Net Metering Service - GS	634	461	641	1,559	552	783	696	272	301
Net Metering Service - RS	-	-	-	-	-	-	-	-	-
Special Contracts	11,600	4,240	-	7,280	-	-	-	-	20,485,158
Curtailable Service Rider 1 - PP	-	-	-	-	-	-	-	-	-
Large Industrial Time-of-Day Svc LITOD	27,432,000	34,272,720	42,009,840	31,610,586	32,337,720	32,927,940	32,327,820	39,549,820	26,423,300
TOTAL	1,602,031,289	1,375,244,857	1,538,893,628	1,343,869,968	1,561,446,911	1,697,264,606	1,594,979,055	1,461,732,390	1,301,672,860

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KWH	Apr-2006	Mar-2006	Feb-2006	Jan-2006	Dec-2005	Nov-2005	Oct-2005	Sep-2005	Aug-2005
Residential Service RS	431,694,371	538,752,739	576,770,686	673,987,728	606,071,002	379,416,361	407,098,108	550,897,467	582,232,687
Volunteer Fire Dept Service VFD	36,788	43,198	51,082	40,421	33,303	20,624	23,443	32,104	34,457
General Service GS	119,192,003	127,535,311	130,455,912	145,700,477	134,771,639	108,509,307	122,136,875	145,360,274	140,600,111
All Electric School AES	9,688,617	10,938,852	11,436,872	12,460,478	11,428,523	8,926,477	9,077,280	10,887,034	8,398,670
Street Lighting Service STL	3,392,373	3,907,629	3,872,138	4,576,272	4,654,583	4,328,628	4,124,416	3,608,586	3,345,887
Private Outdoor Lighting POL	5,765,971	6,649,419	6,533,398	7,741,736	7,862,065	7,284,725	6,926,081	6,101,560	5,657,995
Large Power Service LP	427,897,266	429,004,008	427,639,571	465,867,895	462,761,462	430,758,277	502,487,208	560,317,581	531,551,431
Large Comm/Ind Time-of-Day Svc LCI-TOD	264,540,159	254,708,754	242,885,679	253,155,035	246,750,215	254,830,336	260,257,674	281,695,094	254,347,172
Small Time-of-Day Service STOD	15,725,344	15,301,440	15,485,748	17,055,340	14,941,996	13,559,968	15,255,468	16,913,084	15,970,648
Coal Mining Power Service MP	21,716,349	22,948,832	22,014,824	22,257,163	23,065,105	18,095,952	20,543,280	21,651,850	20,334,371
Large Mine Power Time-of-Day LMP-TOD	23,635,200	23,115,600	21,990,000	24,946,800	25,772,400	20,166,600	20,965,200	16,820,400	16,791,600
Net Metering Service - GS	467	615	684	633	506	381	452	594	698
Net Metering Service - RS	-	-	-	-	-	-	-	-	-
Special Contracts	20,959,305	20,708,474	20,548,239	21,029,378	24,752,967	17,462,617	19,855,234	23,764,887	19,988,669
Curtailable Service Rider 1 - PP	-	-	-	-	-	-	-	-	-
Large Industrial Time-of-Day Svc LITOD	32,196,680	32,025,580	29,315,340	34,468,460	31,154,040	29,932,940	26,931,060	24,262,580	25,093,960
TOTAL	1,376,440,893	1,485,640,451	1,509,000,173	1,683,287,816	1,594,019,806	1,293,293,193	1,415,681,779	1,662,313,095	1,624,348,356

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KWH	Jul-2005	Jun-2005	May-2005	Apr-2005	Mar-2005	Feb-2005	Jan-2005	Dec-2004	Nov-2004
Residential Service RS	583,842,510	423,563,825	359,494,126	428,678,341	555,679,783	600,031,769	649,901,594	518,848,182	342,180,868
Volunteer Fire Dept Service VFD	33,943	27,413	23,675	28,163	30,194	33,964	34,045	27,298	22,242
General Service GS	143,984,739	118,402,466	102,089,640	119,304,611	120,395,552	122,823,647	128,280,251	110,735,738	91,583,150
All Electric School AES	7,972,386	7,832,579	8,057,632	9,001,110	10,838,178	12,123,639	11,918,153	9,485,617	7,700,526
Street Lighting Service STL	3,047,176	2,865,909	3,135,241	3,353,640	3,863,505	3,824,347	4,519,375	4,602,471	4,276,490
Private Outdoor Lighting POL	5,096,726	4,799,378	5,256,604	5,615,542	6,480,465	6,385,976	7,590,134	7,735,402	7,117,582
Large Power Service LP	558,305,201	498,795,929	451,085,046	420,802,528	462,022,335	451,728,780	484,160,648	468,824,841	449,603,544
Large Comm/Ind Time-of-Day Svc LCI-TOD	284,558,720	288,349,838	229,681,325	272,118,272	254,105,045	221,767,145	237,157,501	248,432,491	231,566,364
Small Time-of-Day Service STOD	16,531,448	14,960,864	12,578,120	13,094,568	12,473,888	12,230,872	13,680,612	13,868,036	13,032,376
Coal Mining Power Service MP	21,221,203	23,171,207	24,040,682	25,248,387	26,985,626	25,717,888	24,573,066	23,285,426	20,498,144
Large Mine Power Time-of-Day LMP-TOD	12,483,600	16,110,000	15,739,200	15,604,800	17,487,600	16,467,600	17,383,200	17,385,600	15,042,000
Net Metering Service - GS	1,039	507	226	391	409	370	409	429	271
Net Metering Service - RS	-	-	-	-	-	-	-	-	-
Special Contracts	23,492,749	24,994,062	-	21,813,084	22,755,937	21,276,412	21,914,240	23,779,530	16,498,113
Curtailable Service Rider 1 - PP	12,029	-	-	11,734	26,544	29,269	-	279	14,109
Large Industrial Time-of-Day Svc LITOD	30,329,480	33,721,920	33,522,240	28,956,960	28,829,520	28,235,830	32,855,180	31,975,320	29,474,590
TOTAL	1,690,912,949	1,457,595,897	1,244,703,757	1,363,632,131	1,521,974,581	1,522,677,508	1,633,968,408	1,478,986,660	1,228,610,369

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KWH	Oct-2004	Sep-2004	Aug-2004	Jul-2004	Jun-2004	May-2004	Apr-2004	Mar-2004	Feb-2004
Residential Service RS	353,348,857	454,826,401	472,294,304	520,143,098	445,819,762	364,335,457	423,132,729	486,832,513	652,730,611
Volunteer Fire Dept Service VFD	17,322	16,571	15,010	16,778	13,404	13,170	14,613	18,216	21,872
General Service GS	96,195,794	107,307,462	107,374,978	111,942,290	98,832,153	87,748,114	92,465,437	94,508,734	110,130,337
All Electric School AES	7,582,933	8,827,087	7,574,453	6,895,061	7,359,591	8,290,405	9,606,256	11,399,828	15,272,255
Street Lighting Service STL	4,075,755	3,564,225	3,309,248	3,013,945	2,836,635	3,112,068	3,320,384	3,826,971	3,789,935
Private Outdoor Lighting POL	6,757,632	5,963,823	5,485,008	5,036,570	4,706,367	5,187,213	5,497,044	6,333,591	6,230,874
Large Power Service LP	486,755,292	549,899,382	547,750,835	565,512,407	543,733,475	495,426,550	490,323,515	472,954,128	492,154,821
Large Comm/Ind Time-of-Day Svc LCI-TOD	263,200,080	265,586,366	248,627,431	34,478,682	472,856,343	241,545,032	238,704,200	221,110,711	219,374,025
Small Time-of-Day Service STOD	3,395,692	-	-	(1,835)	1,410,990	1,402,694	1,458,414	1,596,814	1,492,177
Coal Mining Power Service MP	17,959,149	17,936,923	17,712,424	15,708,611	18,276,158	18,600,144	20,434,776	18,064,031	21,922,523
Large Mine Power Time-of-Day LMP-TOD	14,276,400	14,772,000	13,741,200	13,978,800	15,322,800	13,020,000	16,183,200	17,925,600	14,066,400
Net Metering Service - GS	334	382	396	861	411	365	377	231	589
Net Metering Service - RS	-	-	-	-	-	-	-	-	-
Special Contracts	22,017,096	21,013,246	20,304,349	23,407,160	20,401,079	20,860,427	48,216,799	45,670,105	45,635,766
Curtailable Service Rider 1 - PP	17,965	9,904	-	-	-	-	-	-	-
Large Industrial Time-of-Day Svc LITOD	24,423,130	28,778,350	30,768,210	26,467,020	28,429,570	26,696,810	-	-	-
TOTAL	1,300,023,431	1,478,502,122	1,474,957,846	1,326,599,448	1,659,998,738	1,286,238,449	1,349,357,744	1,380,241,473	1,582,822,185

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KWH	Jan-2004	Dec-2003	Nov-2003	Oct-2003	Sep-2003	Aug-2003	Jul-2003	Jun-2003	May-2003
Residential Service RS	680,015,217	528,631,166	339,011,162	332,608,529	491,619,827	498,624,182	499,319,359	343,789,450	335,107,948
Volunteer Fire Dept Service VFD	24,359	19,231	10,464	12,282	13,736	14,049	12,220	10,708	11,002
General Service GS	114,780,985	98,887,585	80,024,500	83,092,722	107,381,554	103,913,673	105,005,833	85,936,432	83,284,555
All Electric School AES	17,187,713	11,193,713	7,664,752	7,451,285	8,909,965	7,325,731	6,368,582	6,358,983	8,084,935
Street Lighting Service STL	4,486,909	4,572,589	4,246,198	4,047,577	3,540,581	3,284,248	2,997,901	2,839,577	3,105,086
Private Outdoor Lighting POL	7,408,287	7,537,185	6,956,306	6,617,842	5,791,413	5,372,979	4,898,747	4,593,939	5,014,541
Large Power Service LP	508,930,717	497,845,537	459,913,566	494,735,291	567,674,080	548,271,346	548,554,907	497,477,680	486,925,132
Large Comm/Ind Time-of-Day Svc LCI-TOD	218,424,149	236,311,491	213,678,108	235,930,265	236,915,501	232,261,525	240,607,801	220,008,962	230,467,906
Small Time-of-Day Service STOD	1,681,621	1,463,217	1,311,772	1,298,805	1,436,748	1,393,741	1,432,633	1,356,551	1,322,416
Coal Mining Power Service MP	22,234,331	22,292,700	20,054,900	19,265,200	18,856,200	19,249,800	15,002,800	20,764,700	19,822,600
Large Mine Power Time-of-Day LMP-TOD	18,920,400	14,997,512	14,145,448	13,625,721	13,120,893	12,088,808	15,025,351	9,549,028	17,525,292
Net Metering Service - GS	513	467	182	272	796	-	579	234	215
Net Metering Service - RS	-	-	-	-	-	-	-	-	-
Special Contracts	52,594,588	45,648,323	45,897,077	39,606,235	45,887,082	36,600,311	43,534,743	40,911,837	40,730,682
Curtailable Service Rider 1 - PP	-	-	-	-	-	-	-	-	-
Large Industrial Time-of-Day Svc LITOD	-	-	-	-	-	-	-	-	-
TOTAL	1,646,689,789	1,469,400,716	1,192,914,435	1,238,292,026	1,501,148,376	1,468,400,393	1,482,761,456	1,233,598,081	1,231,402,310

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KWH	Apr-2003	Mar-2003	Feb-2003	Jan-2003					
Residential Service RS	358,766,311	524,390,402	677,016,200	662,321,153					
Volunteer Fire Dept Service VFD	12,283	18,559	23,804	22,848					
General Service GS	81,953,695	99,027,046	112,402,770	111,021,088					
All Electric School AES	8,338,460	13,013,849	16,334,383	14,663,729					
Street Lighting Service STL	3,322,456	3,837,710	3,822,806	4,491,814					
Private Outdoor Lighting POL	5,350,764	6,187,412	6,087,853	7,278,908					
Large Power Service LP	460,751,161	474,418,570	494,371,597	504,478,352					
Large Comm/Ind Time-of-Day Svc LCI-TOD	207,074,319	218,075,788	226,559,063	219,636,905					
Small Time-of-Day Service STOD	1,307,620	1,466,574	1,633,846	1,620,919					
Coal Mining Power Service MP	21,603,100	19,773,100	23,316,500	22,153,100					
Large Mine Power Time-of-Day LMP-TOD	13,611,039	18,457,586	19,542,609	18,860,390					
Net Metering Service - GS	227	262	425	429					
Net Metering Service - RS	-	-	-	-					
Special Contracts	37,556,505	37,526,643	39,490,139	42,557,455					
Curtailable Service Rider 1 - PP	-	-	-	-					
Large Industrial Time-of-Day Svc LITOD	-	-	-	-					
TOTAL	1,199,647,940	1,416,193,501	1,620,601,995	1,609,107,090					

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. 166

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-166. Please provide the following by month and by billing cycle for the period January 2003 through July 2008 for each KU rate schedule (separately):

a. customers billed; and,
b. billed KWH.

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

A-166. The Company does not separately maintain the customers and KWH billed by billing cycle by rate schedule.

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. 167

Responding Witness: Valerie L. Scott / Robert M. Conroy / William Steven Seelye

Q-167. With regard to KU Purchased Power (Account 555) in Seelye Exhibit 18, page 17, please provide:

a. all workpapers and analyses showing the determination of total demand costs ($15,031,258);
b. all workpapers and analyses showing the determination of total energy costs ($142,211,384);
c. all test year purchased power invoices that include a demand or capacity charge; and,
d. a detailed explanation along with all workpapers and analyses showing the pricing methodology (basis) and amount for sales from LG&E to KU.

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

A-167. a. See attached. The requested information is being provided on CD.

b. See attached. The requested information is being provided on CD.

c. The requested information is not available in Excel. Due to the volume of data requested, the information is being provided on CD.

d. The pricing methodology for intra-company sales is based upon a shared savings approach. The KU and LG&E generating units are jointly dispatched to serve the combined KU and LG&E customers.

After each utility meets its native load and pre-merger sales, the remaining generation is assigned to the other utility's native load and pre-merger sales, if lower in cost than its generation. Inter-company sales to serve native load of the receiving utility are made at fuel costs plus one half of the savings realized by the receiving company. Inter-company sales to serve pre-merger sales of the receiving utility are made at fuel costs plus FGD and SCR consumables and environmental allowance cost. The split savings of intercompany sales is one half the difference of the fuel cost of the energy received for native load and the fuel cost or purchase cost displaced as a result of the transfer. This process was established at the time of the LG&E/KU merger to implement the provisions of the Power Supply System Agreement and has been utilized for fuel adjustment clause purposes since May 1998.

Kentucky Utilities Company
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Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Gross Energy	Energy Jurisdictional Amount	Gross Demand	Demand Jurisdictional Amount	Gross Total	Jurisdictional Total
						0.86841		0.86537		
May-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	2,133	$ 92,804.40	$ 80,592.58	$ -	$ -	$ 92,804.40	$ 80,592.58
May-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	386	39,194.51	34,037.04	-	-	39,194.51	34,037.04
May-07	AECI	Associated Elect Cooperative	Monthly Accrual	7,244	490,862.00	426,271.11	-	-	490,862.00	426,271.11
May-07	AEP	American Electric Power Service Corp.	Monthly Accrual	6,745	421,885.00	366,370.56	-	-	421,885.00	366,370.56
May-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	8,133	582,835.00	506,141.69	-	-	582,835.00	506,141.69
May-07	CITI	Citigroup Energy, Inc.	Monthly Accrual	225	15,850.00	13,764.35	-	-	15,850.00	13,764.35
May-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	2,872	193,441.00	167,986.74	-	-	193,441.00	167,986.74
May-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	6,297	468,066.00	406,474.76	-	-	468,066.00	406,474.76
May-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	38	2,166.00	1,880.98	-	-	2,166.00	1,880.98
May-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	6,571	455,431.00	395,502.35	-	-	455,431.00	395,502.35
May-07	IMBL	Energy Imbalance	Monthly Accrual	16	1,030.51	894.91	-	-	1,030.51	894.91
May-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	1,448	101,003.90	87,713.13	-	-	101,003.90	87,713.13
May-07	PROG	Progress Energy Ventures Inc.	Monthly Accrual	683	47,645.00	41,375.55	-	-	47,645.00	41,375.55
May-07	SOUT	Southern Company Services, Inc	Monthly Accrual	2,120	132,878.00	115,393.03	-	-	132,878.00	115,393.03
May-07	SEMP	Sempra Energy Trading Corp.	Monthly Accrual	200	12,000.00	10,420.96	-	-	12,000.00	10,420.96
May-07	SEPA	Southeastern Power Administration	Monthly Accrual	24	1,377.60	1,196.33	-	-	1,377.60	1,196.33
May-07	TEA	The Energy Authority	Monthly Accrual	200	15,000.00	13,026.20	-	-	15,000.00	13,026.20
May-07	WESC	Williams Energy Marketing & Trading Co	Monthly Accrual	304	23,188.00	20,136.77	-	-	23,188.00	20,136.77
May-07	WSTR	Westar Energy, Inc.	Monthly Accrual	738	50,120.00	43,524.88	-	-	50,120.00	43,524.88
May-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	127,072	2,736,538.22	2,376,446.28	1,287,000.00	1,113,729.92	4,023,538.22	3,490,176.21
May-07	OMU (SEPA)	Owensboro Municipal Utilities	Monthly Accrual	1	57.40	49.85	-	-	57.40	49.85
May-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	27,072	567,645.70	492,951.10	640,149.88	553,965.87	1,207,795.58	1,046,916.97
May-07	OMU	Owensboro Municipal Utilities	True-up of Apr 07 Billing	-	56,890.39	49,404.37	(142,865.43)	(123,631.32)	(85,975.04)	(74,226.94)
May-07	OVEC	Ohio Valley Electric Corporation	True-up of Apr 07 Billing	-	(46,958.89)	(40,779.73)	(569,466.70)	(492,798.84)	(616,425.59)	(533,578.56)
May-07	Intercompany	Intercompany Purchases from LG&E	Native Load		8,322,794.40	7,227,625.65		-	8,322,794.40	7,227,625.65
May-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		3,248.36	2,820.92		-	3,248.36	2,820.92
Jun-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	108,544	2,736,628.80	2,376,524.95	1,463,000.00	1,266,034.87	4,199,628.80	3,642,559.81
Jun-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	32,292	677,098.66	588,001.51	619,484.52	536,082.71	1,296,583.18	1,124,084.22
Jun-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	4,280	240,916.06	209,214.72	-	-	240,916.06	209,214.72
Jun-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	931	126,609.38	109,949.27	-	-	126,609.38	109,949.27
Jun-07	AECI	Associated Elect Cooperative	Monthly Accrual	2,572	160,476.27	139,359.73	-	-	160,476.27	139,359.73
Jun-07	AEP	American Electric Power Service Corp.	Monthly Accrual	6,444	397,894.78	345,537.13	-	-	397,894.78	345,537.13
Jun-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	3,678	223,051.85	193,701.20	-	-	223,051.85	193,701.20
Jun-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	699	36,805.00	31,961.95	-	-	36,805.00	31,961.95
Jun-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	11,333	758,758.47	658,915.97	-	-	758,758.47	658,915.97
Jun-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	1,483	76,819.38	66,710.97	-	-	76,819.38	66,710.97
Jun-07	DECA	Duke Energy Carolinas, Llc	Monthly Accrual	150	10,750.00	9,335.44	-	-	10,750.00	9,335.44
Jun-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	375	9,600.00	8,336.77	-	-	9,600.00	8,336.77
Jun-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	10,691	713,413.00	619,537.36	-	-	713,413.00	619,537.36
Jun-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	1,025	68,225.00	59,247.50	-	-	68,225.00	59,247.50
Jun-07	SOUT	Southern Company Services, Inc	Monthly Accrual	1,703	105,520.22	91,635.17	-	-	105,520.22	91,635.17
Jun-07	SEPA	Southeastern Power Administration	Monthly Accrual	31	1,779.40	1,545.25	-	-	1,779.40	1,545.25
Jun-07	TEA	The Energy Authority	Monthly Accrual	125	8,200.00	7,120.99	-	-	8,200.00	7,120.99
Jun-07	WSTR	Westar Energy, Inc.	Monthly Accrual	328	21,604.00	18,761.20	-	-	21,604.00	18,761.20
Jun-07	OMU	Owensboro Municipal Utilities	True-up of May 07 Billing		(174,878.57)	(151,866.88)	(155,171.29)	(134,280.43)	(330,049.86)	(286,147.31)
Jun-07	OVEC	Ohio Valley Electric Corporation	True-up of May 07 Billing	-	1,237.83	1,074.95	(592,623.14)	(512,837.70)	(591,385.31)	(511,762.76)
Jun-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from May 07	-	5.16	4.48	-	-	5.16	4.48
Jun-07	Intercompany	Intercompany Purchases from LG&E	Native Load		6,560,469.03	5,697,198.79		-	6,560,469.03	5,697,198.79
Jun-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		59,880.37	52,000.91		-	59,880.37	52,000.91
Jul-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	129,951	3,152,912.62	2,738,031.37	1,470,000.00	1,272,092.45	4,622,912.62	4,010,123.82
Jul-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	29,211	612,496.25	531,899.91	640,136.51	553,954.30	1,252,632.76	1,085,854.21
Jul-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	1,687	90,967.45	78,997.35	-	-	90,967.45	78,997.35
Jul-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	222	22,093.77	19,186.52	-	-	22,093.77	19,186.52
Jul-07	AEP	American Electric Power Service Corp.	Monthly Accrual	1,417	80,137.29	69,592.29	-	-	80,137.29	69,592.29
Jul-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	700	42,800.00	37,168.09	-	-	42,800.00	37,168.09
Jul-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	449	21,934.00	19,047.78	-	-	21,934.00	19,047.78
Jul-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	1,675	93,482.55	81,181.49	-	-	93,482.55	81,181.49
Jul-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Jun 07	-	630.03	547.13	-	-	630.03	547.13
Jul-07	OMU	Owensboro Municipal Utilities	True-up of Jun 07 Billing	-	107,879.54	93,684.03	7,541.65	6,526.31	115,421.19	100,210.34
Jul-07	OVEC	Ohio Valley Electric Corporation	True-up of Jun 07 Billing		(275.64)	(239.37)	(500,959.54)	(433,514.86)	(501,235.18)	(433,754.23)
Jul-07	Intercompany	Intercompany Purchases from LG&E	Native Load		5,911,293.60	5,133,446.19		-	5,911,293.60	5,133,446.19
Jul-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		3,858.45	3,350.73		-	3,858.45	3,350.73
Aug-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	115,710	2,806,080.20	2,436,837.47	1,344,900.00	1,163,834.79	4,150,980.20	3,600,672.26
Aug-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	30,199	633,212.63	549,890.29	640,136.76	553,954.52	1,273,349.39	1,103,844.81
Aug-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	27,853	1,822,073.24	1,582,312.70	-	-	1,822,073.24	1,582,312.70

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General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Gross Energy	Energy Jurisdictional Amount	Gross Demand	Demand Jurisdictional Amount	Gross Total	Jurisdictional Total
						0.86841		0.86537		
Aug-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	1,541	192,115.99	166,836.09	-	-	192,115.99	166,836.09
Aug-07	PJM	Pjm Interconnection Association	Monthly Accrual	5	302.45	262.65	-	-	302.45	262.65
Aug-07	AECI	Associated Elect Cooperative	Monthly Accrual	5,555	464,095.79	403,026.97	-	-	464,095.79	403,026.97
Aug-07	AEP	American Electric Power Service Corp.	Monthly Accrual	3,003	233,158.58	202,478.02	-	-	233,158.58	202,478.02
Aug-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	3,968	245,467.00	213,166.82	-	-	245,467.00	213,166.82
Aug-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	6,202	664,182.99	576,785.37	-	-	664,182.99	576,785.37
Aug-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	100	6,300.00	5,471.00	-	-	6,300.00	5,471.00
Aug-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	1,237	96,580.00	83,871.36	-	-	96,580.00	83,871.36
Aug-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	1,435	139,569.61	121,204.11	-	-	139,569.61	121,204.11
Aug-07	KCPL	Kansas City Power & Light	Monthly Accrual	9	810.00	703.41	-	-	810.00	703.41
Aug-07	IMBL	Energy Imbalance	Monthly Accrual	249	16,137.90	14,014.37	-	-	16,137.90	14,014.37
Aug-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	801	105,129.00	91,295.43	-	-	105,129.00	91,295.43
Aug-07	PROG	Progress Energy Ventures Inc.	Monthly Accrual	800	81,700.00	70,949.37	-	-	81,700.00	70,949.37
Aug-07	TEA	The Energy Authority	Monthly Accrual	1,359	152,925.00	132,802.11	-	-	152,925.00	132,802.11
Aug-07	TALT	Transalta Energy Marketing (U.S.) Inc.	Monthly Accrual	763	99,160.25	86,112.08	-	-	99,160.25	86,112.08
Aug-07	TVA	Tennessee Valley Authority	Monthly Accrual	1,295	168,350.00	146,197.39	-	-	168,350.00	146,197.39
Aug-07	WSTR	Westar Energy, Inc.	Monthly Accrual	926	102,879.98	89,342.35	-	-	102,879.98	89,342.35
Aug-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	-	775.84	673.75	-	-	775.84	673.75
Aug-07	OMU (SEPA)	Owensboro Municipal Utilities	True-up of Jul 07 Billing	(1)	(57.40)	(49.85)	-	-	(57.40)	(49.85)
Aug-07	OMU	Owensboro Municipal Utilities	True-up of Jul 07 Billing	-	(156,009.00)	(135,480.30)	(180,162.77)	(155,907.28)	(336,171.77)	(291,387.58)
Aug-07	OVEC	Ohio Valley Electric Corporation	True-up of Jul 07 Billing	-	24,299.84	21,102.31	(563,493.73)	(487,630.01)	(539,193.89)	(466,527.71)
Aug-07	Intercompany	Intercompany Purchases from LG&E	Native Load		7,648,195.18	6,641,794.69		-	7,648,195.18	6,641,794.69
Aug-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		565.19	490.82		-	565.19	490.82
Sep-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	114,377	2,885,823.78	2,506,087.86	1,338,200.00	1,158,036.82	4,224,023.78	3,664,124.67
Sep-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	29,387	616,186.62	535,104.68	619,502.17	536,097.98	1,235,688.79	1,071,202.66
Sep-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	10,427	590,213.36	512,549.15	-	-	590,213.36	512,549.15
Sep-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	73	7,258.31	6,303.21	-	-	7,258.31	6,303.21
Sep-07	AECI	Associated Elect Cooperative	Monthly Accrual	1,241	81,341.67	70,638.19	-	-	81,341.67	70,638.19
Sep-07	AEP	American Electric Power Service Corp.	Monthly Accrual	2,169	119,357.28	103,651.45	-	-	119,357.28	103,651.45
Sep-07	AMEM	Ameren Energy Marketing Company	Monthly Accrual	1,304	69,112.00	60,017.78	-	-	69,112.00	60,017.78
Sep-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	1,152	65,135.79	56,564.79	-	-	65,135.79	56,564.79
Sep-07	CITI	Citigroup Energy, Inc.	Monthly Accrual	93	5,115.00	4,441.93	-	-	5,115.00	4,441.93
Sep-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	1,329	74,124.36	64,370.58	-	-	74,124.36	64,370.58
Sep-07	DECA	Duke Energy Carolinas, Llc	Monthly Accrual	1,800	109,150.00	94,787.32	-	-	109,150.00	94,787.32
Sep-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	50	3,000.00	2,605.24	-	-	3,000.00	2,605.24
Sep-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	1,694	115,779.92	100,544.83	-	-	115,779.92	100,544.83
Sep-07	IMBL	Energy Imbalance	Monthly Accrual	79	3,368.03	2,924.84	-	-	3,368.03	2,924.84
Sep-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	101	5,656.00	4,911.75	-	-	5,656.00	4,911.75
Sep-07	PROG	Progress Energy Ventures Inc.	Monthly Accrual	26	1,426.37	1,238.68	-	-	1,426.37	1,238.68
Sep-07	TEA	The Energy Authority	Monthly Accrual	48	3,120.00	2,709.45	-	-	3,120.00	2,709.45
Sep-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Aug 07	-	4,975.64	4,320.91	-	-	4,975.64	4,320.91
Sep-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Aug 07	-	6.33	5.50	-	-	6.33	5.50
Sep-07	OMU	Owensboro Municipal Utilities	True-up of Aug 07 Billing	-	100,345.48	87,141.35	(7,802.28)	(6,751.85)	92,543.20	80,389.50
Sep-07	OVEC	Ohio Valley Electric Corporation	True-up of Aug 07 Billing	-	24,344.78	21,141.33	(531,849.86)	(460,246.39)	(507,505.08)	(439,105.06)
Sep-07	OVEC	Ohio Valley Electric Corporation	True-up of Jun 07 Billing	-	(2.66)	(2.31)	-		(2.66)	(2.31)
Sep-07	Intercompany	Intercompany Purchases from LG&E	Native Load		4,496,858.22	3,905,131.65		-	4,496,858.22	3,905,131.65
Sep-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		82,043.57	71,247.73		-	82,043.57	71,247.73
Oct-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	130,404	3,048,690.34	2,647,523.35	1,293,200.00	1,119,095.21	4,341,890.34	3,766,618.56
Oct-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	27,079	567,792.47	493,078.55	640,133.62	553,951.80	1,207,926.09	1,047,030.35
Oct-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	5,205	342,316.45	297,272.17	-	-	342,316.45	297,272.17
Oct-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	9	926.27	804.39	-	-	926.27	804.39
Oct-07	AECI	Associated Elect Cooperative	Monthly Accrual	198	12,576.00	10,921.17	-	-	12,576.00	10,921.17
Oct-07	AEP	American Electric Power Service Corp.	Monthly Accrual	2,116	129,794.08	112,714.91	-	-	129,794.08	112,714.91
Oct-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	353	22,590.21	19,617.64	-	-	22,590.21	19,617.64
Oct-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	735	37,402.00	32,480.40	-	-	37,402.00	32,480.40
Oct-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	170	9,354.75	8,123.79	-	-	9,354.75	8,123.79
Oct-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	50	3,350.00	2,909.18	-	-	3,350.00	2,909.18
Oct-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	100	4,650.00	4,038.12	-	-	4,650.00	4,038.12
Oct-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	1,300	82,100.00	71,296.73	-	-	82,100.00	71,296.73
Oct-07	IMBL	Energy Imbalance	Monthly Accrual	37	3,032.25	2,633.25	-	-	3,032.25	2,633.25
Oct-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	231	14,134.00	12,274.15	-	-	14,134.00	12,274.15
Oct-07	SOUT	Southern Company Services, Inc	Monthly Accrual	186	27,543.77	23,919.38	-	-	27,543.77	23,919.38
Oct-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Sep 07	-	4.84	4.20	-	-	4.84	4.20
Oct-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Sep 07	-	12.91	11.21	-		12.91	11.21
Oct-07	OMU	Owensboro Municipal Utilities	True-up of Sep 07 Billing	-	74,131.13	64,376.46	(46,967.10)	(40,643.87)	27,164.03	23,732.59

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Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Gross Energy	Energy Jurisdictional Amount	Gross Demand	Demand Jurisdictional Amount	Gross Total	Jurisdictional Total
						0.86841		0.86537		
Oct-07	OVEC	Ohio Valley Electric Corporation	True-up of Sep 07 Billing	-	20,520.79	17,820.53	(312,810.03)	(270,696.11)	(292,289.24)	(252,875.58)
Oct-07	Intercompany	Intercompany Purchases from LG&E	Native Load		6,525,961.39	5,667,231.90		-	6,525,961.39	5,667,231.90
Oct-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		23,577.89	20,475.35		-	23,577.89	20,475.35
Nov-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	102,436	2,707,572.99	2,351,292.49	1,279,200.00	1,106,980.04	3,986,772.99	3,458,272.54
Nov-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	30,678	643,256.30	558,612.35	619,491.67	536,088.90	1,262,747.97	1,094,701.25
Nov-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	18,908	964,526.67	837,607.82	-	-	964,526.67	837,607.82
Nov-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	260	25,956.01	22,540.55	-	-	25,956.01	22,540.55
Nov-07	PJM	Pjm Interconnection Association	Monthly Accrual	2,491	133,009.69	115,507.39	-	-	133,009.69	115,507.39
Nov-07	AECI	Associated Elect Cooperative	Monthly Accrual	1,542	89,234.01	77,492.00	-	-	89,234.01	77,492.00
Nov-07	AEP	American Electric Power Service Corp.	Monthly Accrual	4,420	253,304.77	219,973.24	-	-	253,304.77	219,973.24
Nov-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	4,377	273,544.00	237,549.26	-	-	273,544.00	237,549.26
Nov-07	CITI	Citigroup Energy, Inc.	Monthly Accrual	22	1,342.00	1,165.41	-	-	1,342.00	1,165.41
Nov-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	175	9,500.00	8,249.93	-	-	9,500.00	8,249.93
Nov-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	1,381	87,050.90	75,596.16	-	-	87,050.90	75,596.16
Nov-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	297	20,396.00	17,712.16	-	-	20,396.00	17,712.16
Nov-07	DECA	Duke Energy Carolinas, Llc	Monthly Accrual	384	27,648.00	24,009.89	-	-	27,648.00	24,009.89
Nov-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	402	24,120.79	20,946.82	-	-	24,120.79	20,946.82
Nov-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	1,533	88,107.47	76,513.70	-	-	88,107.47	76,513.70
Nov-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	419	30,942.10	26,870.53	-	-	30,942.10	26,870.53
Nov-07	TEA	The Energy Authority	Monthly Accrual	720	48,273.57	41,921.41	-	-	48,273.57	41,921.41
Nov-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Oct 07	-	19.58	17.00	-	-	19.58	17.00
Nov-07	OMU	Owensboro Municipal Utilities	True-up of Oct 07 Billing	-	53,152.14	46,158.03	(14,398.77)	(12,460.25)	38,753.37	33,697.78
Nov-07	OVEC	Ohio Valley Electric Corporation	True-up of Oct 07 Billing	-	(11,568.33)	(10,046.09)	(483,334.38)	(418,262.60)	(494,902.71)	(428,308.69)
Nov-07	Intercompany	Intercompany Purchases from LG&E	Native Load		6,664,635.95	5,787,658.74		-	6,664,635.95	5,787,658.74
Nov-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		33,044.37	28,696.17		-	33,044.37	28,696.17
Dec-07	OMU	Owensboro Municipal Utilities	Monthly Accrual	69,775	2,386,481.04	2,072,451.96	1,328,200.00	1,149,383.13	3,714,681.04	3,221,835.09
Dec-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	31,274	655,753.23	569,464.85	640,136.55	553,954.34	1,295,889.78	1,123,419.19
Dec-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	2,079	115,777.25	100,542.51	-	-	115,777.25	100,542.51
Dec-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	154	16,948.29	14,718.12	-	-	16,948.29	14,718.12
Dec-07	PJM	Pjm Interconnection Association	Monthly Accrual	1,525	71,197.47	61,828.83	-	-	71,197.47	61,828.83
Dec-07	AECI	Associated Elect Cooperative	Monthly Accrual	388	26,256.00	22,801.06	-	-	26,256.00	22,801.06
Dec-07	AEP	American Electric Power Service Corp.	Monthly Accrual	2,144	141,264.89	122,676.31	-	-	141,264.89	122,676.31
Dec-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	1,164	80,839.81	70,202.37	-	-	80,839.81	70,202.37
Dec-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	525	36,500.00	31,697.09	-	-	36,500.00	31,697.09
Dec-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	50	1,600.00	1,389.46	-	-	1,600.00	1,389.46
Dec-07	OMU	Owensboro Municipal Utilities	True-up of Nov 07 Billing	-	203,292.35	176,541.79	48,725.64	42,165.66	252,017.99	218,707.45
Dec-07	OVEC	Ohio Valley Electric Corporation	True-up of Nov 07 Billing	-	(13,161.66)	(11,429.76)	(549,272.92)	(475,323.77)	(562,434.58)	(486,753.53)
Dec-07	OMU	Owensboro Municipal Utilities	True-up of Jul 07 Billing	-	685.00	594.86	-	-	685.00	594.86
Dec-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Nov 07	-	700.58	608.39	-	-	700.58	608.39
Dec-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Nov 07	-	12.45	10.81	-	-	12.45	10.81
Dec-07	MISO	Midwest Independent Transmission System Operator, Inc.	Prior Period Adjustment from Nov 07	-	6.82	5.92	-	-	6.82	5.92
Dec-07	EKPC	East Kentucky Power Cooperative	Prior Period Adjustment from Nov 07	-	8,618.78	7,484.66	-	-	8,618.78	7,484.66
Dec-07	EKPC	East Kentucky Power Cooperative	Prior Period Adjustment from Nov 07	-	(128.16)	(111.30)	-	-	(128.16)	(111.30)
Dec-07	CONS	Constellation Energy Comds. Grp. Inc.	Prior Period Adjustment from Nov 07	(2)	(73.93)	(64.20)	-	-	(73.93)	(64.20)
Dec-07	EKPC	East Kentucky Power Cooperative	Prior Period Adjustment from Nov 07	130	7,800.00	6,773.62	-	-	7,800.00	6,773.62
Dec-07	Intercompany	Intercompany Purchases from LG&E	Native Load		8,909,821.04	7,737,407.41		-	8,909,821.04	7,737,407.41
Dec-07	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		43.96	38.18		-	43.96	38.18
Jan-08	OMU	Owensboro Municipal Utilities	Monthly Accrual	99,929	2,834,518.96	2,461,534.07	1,278,200.00	1,106,114.68	4,112,718.96	3,567,648.74
Jan-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	36,119	757,343.19	657,686.93	722,441.48	625,178.47	1,479,784.67	1,282,865.40
Jan-08	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	12,092	720,420.36	625,622.65	-	-	720,420.36	625,622.65
Jan-08	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	40	4,089.89	3,551.72	-	-	4,089.89	3,551.72
Jan-08	PJM	Pjm Interconnection Association	Monthly Accrual	10,925	743,723.13	645,859.08	-	-	743,723.13	645,859.08
Jan-08	AECI	Associated Elect Cooperative	Monthly Accrual	2,652	190,890.00	165,771.42	-	-	190,890.00	165,771.42
Jan-08	AEP	American Electric Power Service Corp.	Monthly Accrual	3,292	246,771.89	214,300.00	-	-	246,771.89	214,300.00
Jan-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	4,049	286,710.46	248,983.19	-	-	286,710.46	248,983.19
Jan-08	COBB	Cobb Electric Membership Corporation	Monthly Accrual	829	61,032.86	53,001.75	-	-	61,032.86	53,001.75
Jan-08	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	384	25,170.00	21,857.96	-	-	25,170.00	21,857.96
Jan-08	DECA	Duke Energy Carolinas, Llc	Monthly Accrual	1,000	75,050.00	65,174.42	-	-	75,050.00	65,174.42
Jan-08	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	125	10,475.00	9,096.63	-	-	10,475.00	9,096.63
Jan-08	IMBL	Energy Imbalance	Monthly Accrual	8	650.64	565.02	-	-	650.64	565.02
Jan-08	SOUT	Southern Company Services, Inc	Monthly Accrual	1,100	80,300.00	69,733.59	-	-	80,300.00	69,733.59
Jan-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Dec 07	-	(11.20)	(9.73)		-	(11.20)	(9.73)
Jan-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Dec 07	-	(1.04)	(0.90)	-	-	(1.04)	(0.90)
Jan-08	OMU	Owensboro Municipal Utilities	True-up of Dec 07 Billing	-	(22,291.92)	(19,358.60)	(50,173.68)	(43,418.75)	(72,465.60)	(62,777.35)
Jan-08	OVEC	Ohio Valley Electric Corporation	True-up of Dec 07 Billing	-	19,187.78	16,662.92	(500,341.19)	(432,979.76)	(481,153.41)	(416,316.84)

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Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Gross Energy	0.86841 Energy Jurisdictional Amount	Gross Demand	0.86537 Demand Jurisdictional Amount	Gross Total	Jurisdictional Total
Jan-08	Intercompany	Intercompany Purchases from LG&E	Native Load		10,770,545.12	9,353,285.02		-	10,770,545.12	9,353,285.02
Feb-08	OMU	Owensboro Municipal Utilities	Monthly Accrual	123,717	3,283,951.84	2,851,827.57	1,367,000.00	1,182,959.44	4,650,951.84	4,034,787.02
Feb-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	27,273	571,860.26	496,611.08	652,224.48	564,414.86	1,224,084.74	1,061,025.93
Feb-08	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	43,242	2,699,902.58	2,344,631.41	-	-	2,699,902.58	2,344,631.41
Feb-08	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	200	23,596.27	20,491.32	-	-	23,596.27	20,491.32
Feb-08	PJM	Pjm Interconnection Association	Monthly Accrual	37,464	2,406,342.86	2,089,700.23	-	-	2,406,342.86	2,089,700.23
Feb-08	AECI	Associated Elect Cooperative	Monthly Accrual	1,297	91,225.00	79,221.01	-	-	91,225.00	79,221.01
Feb-08	AEP	American Electric Power Service Corp.	Monthly Accrual	4,248	284,249.00	246,845.62	-	-	284,249.00	246,845.62
Feb-08	AMEM	Ameren Energy Marketing Company	Monthly Accrual	75	5,025.00	4,363.78	-	-	5,025.00	4,363.78
Feb-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	2,910	178,800.00	155,272.30	-	-	178,800.00	155,272.30
Feb-08	COBB	Cobb Electric Membership Corporation	Monthly Accrual	1,119	84,273.00	73,183.80	-	-	84,273.00	73,183.80
Feb-08	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	3,420	246,820.00	214,341.78	-	-	246,820.00	214,341.78
Feb-08	*DTE*	*Dte Energy Trading, Inc.*	*Monthly Accrual*	200	9,600.00	8,336.77	-	-	9,600.00	8,336.77
Feb-08	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	744	56,850.00	49,369.30	-	-	56,850.00	49,369.30
Feb-08	SOUT	Southern Company Services, Inc	Monthly Accrual	100	7,500.00	6,513.10	-	-	7,500.00	6,513.10
Feb-08	TEA	The Energy Authority	Monthly Accrual	666	45,656.00	39,648.28	-	-	45,656.00	39,648.28
Feb-08	TVA	Tennessee Valley Authority	Monthly Accrual	451	28,004.00	24,319.05	-	-	28,004.00	24,319.05
Feb-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Jan 08	-	442.54	384.31	-	-	442.54	384.31
Feb-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Jan 08	-	41.30	35.87	-	-	41.30	35.87
Feb-08	PJM	Pjm Interconnection Association	Prior Period Adjustment from Jan 08	-	7.32	6.36	-	-	7.32	6.36
Feb-08	OMU	Owensboro Municipal Utilities	True-up of Jan 08 Billing	-	(62,346.91)	(54,142.89)	(88,261.26)	(76,378.56)	(150,608.17)	(130,521.45)
Feb-08	OVEC	Ohio Valley Electric Corporation	True-up of Jan 08 Billing	-	(60,159.69)	(52,243.48)	(186,706.07)	(161,569.65)	(246,865.76)	(213,813.13)
Feb-08	Intercompany	Intercompany Purchases from LG&E	Native Load		7,524,982.72	6,534,795.35		-	7,524,982.72	6,534,795.35
Feb-08	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		430.98	374.27		-	430.98	374.27
Mar-08	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	29,491	2,035,976.84	1,768,069.44	-	-	2,035,976.84	1,768,069.44
Mar-08	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	765	86,521.91	75,136.78	-	-	86,521.91	75,136.78
Mar-08	PJM	Pjm Interconnection Association	Monthly Accrual	39,070	2,711,653.22	2,354,835.82	-	-	2,711,653.22	2,354,835.82
Mar-08	AEP	American Electric Power Service Corp.	Monthly Accrual	1,160	87,199.77	75,725.44		-	87,199.77	75,725.44
Mar-08	AMEM	Ameren Energy Marketing Company	Monthly Accrual	500	32,500.00	28,223.43		-	32,500.00	28,223.43
Mar-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	2,199	181,291.24	157,435.73	-	-	181,291.24	157,435.73
Mar-08	CITI	Citigroup Energy, Inc.	Monthly Accrual	100	8,500.00	7,381.51		-	8,500.00	7,381.51
Mar-08	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	75	6,750.00	5,861.79	-	-	6,750.00	5,861.79
Mar-08	DTE	Dte Energy Trading, Inc.	Monthly Accrual	100	7,200.00	6,252.58	-	-	7,200.00	6,252.58
Mar-08	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	450	34,400.00	29,873.42	-	-	34,400.00	29,873.42
Mar-08	BREC	Big Rivers Electric Corp.	Monthly Accrual	31	2,866.52	2,489.32	-	-	2,866.52	2,489.32
Mar-08	OMU	Owensboro Municipal Utilities	Monthly Accrual	16,603	1,596,057.20	1,386,037.36	1,356,772.00	1,174,108.45	2,952,829.20	2,560,145.81
Mar-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	31,230	654,830.64	568,663.66	723,545.13	626,133.54	1,378,375.77	1,194,797.20
Mar-08	OMU	Owensboro Municipal Utilities	True-up of Feb 08 Billing	-	392,586.56	340,927.40	(10,193.07)	(8,820.77)	382,393.49	332,106.64
Mar-08	OMU	Owensboro Municipal Utilities	True-up of Jan 08 Billing		124,693.82	108,285.78	176,522.52	152,757.12	301,216.34	261,042.90
Mar-08	OVEC	Ohio Valley Electric Corporation	True-up of Feb 08 Billing	-	4,495.11	3,903.61	(164,592.85)	(142,433.55)	(160,097.74)	(138,529.94)
Mar-08	OVEC	Ohio Valley Electric Corporation	True-up of Dec 07 Billing	-	-	-	358,325.16	310,083.49	358,325.16	310,083.49
Mar-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Feb 08	-	75.74	65.77	-	-	75.74	65.77
Mar-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Feb 08	-	7.07	6.14	-	-	7.07	6.14
Mar-08	PJM	Pjm Interconnection Association	Prior Period Adjustment from Feb 08	-	162.73	141.32	-	-	162.73	141.32
Mar-08	Intercompany	Intercompany Purchases from LG&E	Native Load		8,474,004.16	7,358,938.22		-	8,474,004.16	7,358,938.22
Mar-08	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		88,317.16	76,695.80		-	88,317.16	76,695.80
Apr-08	OMU	Owensboro Municipal Utilities	Monthly Accrual	15,159	1,560,503.52	1,355,162.07	1,372,722.68	1,187,911.67	2,933,226.20	2,543,073.74
Apr-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	30,997	649,945.10	564,420.99	699,143.69	605,017.29	1,349,088.79	1,169,438.28
Apr-08	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	36,009	2,488,120.76	2,160,717.25	-	-	2,488,120.76	2,160,717.25
Apr-08	PJM	Pjm Interconnection Association	Monthly Accrual	32,854	2,517,654.88	2,186,365.07	-	-	2,517,654.88	2,186,365.07
Apr-08	AECI	Associated Elect Cooperative	Monthly Accrual	773	56,456.00	49,027.14	-	-	56,456.00	49,027.14
Apr-08	AEP	American Electric Power Service Corp.	Monthly Accrual	1,000	83,350.00	72,382.25	-	-	83,350.00	72,382.25
Apr-08	AMEM	Ameren Energy Marketing Company	Monthly Accrual	150	13,500.00	11,723.58	-	-	13,500.00	11,723.58
Apr-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	691	59,721.51	51,862.96	-	-	59,721.51	51,862.96
Apr-08	COBB	Cobb Electric Membership Corporation	Monthly Accrual	286	21,255.00	18,458.13	-	-	21,255.00	18,458.13
Apr-08	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	814	63,678.99	55,299.68	-	-	63,678.99	55,299.68
Apr-08	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	800	72,000.00	62,525.76	-	-	72,000.00	62,525.76
Apr-08	IMBL	Energy Imbalance	Monthly Accrual	589	42,680.02	37,063.90	-	-	42,680.02	37,063.90
Apr-08	*TEA*	*The Energy Authority*	*Monthly Accrual*	2,336	199,552.00	173,293.62	-	-	199,552.00	173,293.62
Apr-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Mar 08	-	825.77	717.11		-	825.77	717.11
Apr-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Mar 08	-	151.21	131.31	-	-	151.21	131.31
Apr-08	OMU	Owensboro Municipal Utilities	True-up of Mar 08 Billing	-	(8,082.26)	(7,018.74)	15,977.04	13,826.04	7,894.78	6,807.29
Apr-08	OVEC	Ohio Valley Electric Corporation	True-up of Mar 08 Billing	-	(18,868.00)	(16,385.22)	(107,916.48)	(93,387.58)	(126,784.48)	(109,772.80)
Apr-08	Intercompany	Intercompany Purchases from LG&E	Native Load		6,625,876.79	5,753,999.77		-	6,625,876.79	5,753,999.77
Apr-08	Intercompany	Intercompany Purchases from LG&E	Off-System Sales		42,405.41	36,825.42		-	42,405.41	36,825.42

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Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Gross Energy	Energy Jurisdictional Amount	Gross Demand	Demand Jurisdictional Amount	Gross Total	Jurisdictional Total
						0.86841		0.86537		
May-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,458.96)	(9,050.86)	(10,458.96)	(9,050.86)
May-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
May-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(140,053.66)	(121,198.10)	(140,053.66)	(121,198.10)
May-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				42,287.00	36,593.86	42,287.00	36,593.86
May-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(87,300.00)	(75,546.72)	(87,300.00)	(75,546.72)
Jun-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Jun-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(11,224.66)	(9,713.47)	(11,224.66)	(9,713.47)
Jun-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(127,910.81)	(110,690.05)	(127,910.81)	(110,690.05)
Jul-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(11,224.66)	(9,713.47)	(11,224.66)	(9,713.47)
Jul-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Jul-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(112,910.81)	(97,709.52)	(112,910.81)	(97,709.52)
Aug-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,446.18)	(9,039.80)	(10,446.18)	(9,039.80)
Aug-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Aug-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(94,910.80)	(82,132.87)	(94,910.80)	(82,132.87)
Sep-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,015.18)	(8,666.83)	(10,015.18)	(8,666.83)
Sep-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Sep-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(114,285.81)	(98,899.40)	(114,285.81)	(98,899.40)
Oct-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Oct-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,015.18)	(8,666.83)	(10,015.18)	(8,666.83)
Oct-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(129,285.80)	(111,879.93)	(129,285.80)	(111,879.93)
Nov-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,015.18)	(8,666.83)	(10,015.18)	(8,666.83)
Nov-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Nov-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(136,785.81)	(118,370.20)	(136,785.81)	(118,370.20)
Dec-07	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,015.18)	(8,666.83)	(10,015.18)	(8,666.83)
Dec-07	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Dec-07	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(3,385.80)	(2,929.97)	(3,385.80)	(2,929.97)
Jan-08	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,015.18)	(8,666.83)	(10,015.18)	(8,666.83)
Jan-08	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Jan-08	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(95,258.33)	(82,433.61)	(95,258.33)	(82,433.61)
Feb-08	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,785.58)	(9,333.51)	(10,785.58)	(9,333.51)
Feb-08	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Feb-08	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(87,521.97)	(75,738.80)	(87,521.97)	(75,738.80)
Mar-08	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,509.19)	(11,690.43)	(13,509.19)	(11,690.43)
Mar-08	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,785.58)	(9,333.51)	(10,785.58)	(9,333.51)
Mar-08	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(76,941.97)	(66,583.20)	(76,941.97)	(66,583.20)
Apr-08	OMU	Owensboro Municipal Utilities	Interest on OMU Debt Service Reserve				(10,785.58)	(9,333.51)	(10,785.58)	(9,333.51)
Apr-08	OMU	Owensboro Municipal Utilities	Record receivable for KU share of OMU emission allowances				(13,133.38)	(11,365.22)	(13,133.38)	(11,365.22)
Apr-08	OMU	Owensboro Municipal Utilities	Record OMU Construction Credit for Scrubber				(61,097.53)	(52,871.91)	(61,097.53)	(52,871.91)
			Total		$ 163,760,018.92	$142,211,384.30	$ 17,369,766.94	$ 15,031,258.12	$ 181,129,785.86	$ 157,242,642.42

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended May 31, 2007

PRE-MERGER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU				$21.53533603	127,072	$2,736,538.22	$1,287,000.00	$4,023,538.22
OVEC	SURPLUS				27,072	$567,645.70	$640,149.88	$1,207,795.58
TOTAL PREMERGER PURCHASES					154,144	$3,304,183.92	$1,927,149.88	$5,231,333.80

OTHER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	2133	92,804.40	2133	$92,804.40	$0.00	$92,804.40
MCRS	OSS	0	(0.00)	386	$39,194.51	$0.00	$39,194.51
AECI				7244	$490,862.00	$0.00	$490,862.00
AEP				6745	$421,885.00	$0.00	$421,885.00
BP				0	$0.00	$0.00	$0.00
CARG				8133	$582,835.00	$0.00	$582,835.00
CTTI				225	$15,850.00	$0.00	$15,850.00
COBB				2872	$193,441.00	$0.00	$193,441.00
CONS				6297	$468,066.00	$0.00	$468,066.00
DTE				38	$2,166.00	$0.00	$2,166.00
EKPC				0	$0.00	$0.00	$0.00
FORT				6571	$455,431.00	$0.00	$455,431.00
IMEA				0	$0.00	$0.00	$0.00
IMPA				0	$0.00	$0.00	$0.00
IMBL	DOLLARS RECORDED BY CORPORATE ACCOUNTING			16	$1,030.51	$0.00	$1,030.51
MLCM				1448	$101,003.90	$0.00	$101,003.90
OVEC				0	$0.00	$0.00	$0.00
OMU				0	$0.00	$0.00	$0.00
PROG				683	$47,645.00	$0.00	$47,645.00
SOUT				2120	$132,878.00	$0.00	$132,878.00
SEMP				200	$12,000.00	$0.00	$12,000.00
SEPA	(OMU)			24	$1,377.60	$0.00	$1,377.60
TEA				200	$15,000.00	$0.00	$15,000.00
TVA				0	$0.00	$0.00	$0.00
WESC				304	$23,188.00	$0.00	$23,188.00
WSTR				738	$50,120.00	$0.00	$50,120.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended May 31, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	46377	$3,146,777.92	$0.00	$3,146,777.92
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				96%
INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	406497		$7,878,666.71	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$444,127.69	NI
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer(INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	0	$0.00		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	40	$3,248.36		OSS
			406,497	$8,322,794.40
			40	$3,248.36
TOTAL	406537	$8,326,042.76	406,537	$ 8,326,042.76

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG		price chan	Apr-07	0	$0.00	$0.00	$0.00
SEPA (OMU)		reels betw	Apr-07	1	$57.40	$0.00	$57.40
	0	0		0	$0.00	$0.00	$0.00
	0	0		0	$0.00	$0.00	$0.00
	0	0		0		$0.00	$0.00
				0		$0.00	$0.00
TOTAL				1	$57.40	$0.00	$57.40

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended May 31, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS	MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)	0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)			$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU	0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)	0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS	0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Apr 07 Billing	0	$56,890.39	($142,865.43)	($85,975.04)
OVEC	True-up of Apr 07 Billing	0	($46,958.89)	($569,466.70)	($616,425.59)
OVEC		0	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$9,931.50	($712,332.13)	($702,400.63)

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended June 30, 2007

PRE-MERGER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU			$25.21216097	108,544	$2,736,628.80	$1,463,000.00	$4,199,628.80
OVEC	SURPLUS			32,292	$677,098.66	$619,484.52	$1,296,583.18
TOTAL PREMERGER PURCHASES				140,836	$3,413,727.46	$2,082,484.52	$5,496,211.98

OTHER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	ML	4266	239,573.18	4280	$240,916.06	$0.00	$240,916.06
MCRS	OSS	11	1,342.88	931	$126,609.38	$0.00	$126,609.38
AECI				2572	$160,476.27	$0.00	$160,476.27
AEP				6444	$397,894.78	$0.00	$397,894.78
BP				0	$0.00	$0.00	$0.00
CARG				4678	$223,051.85	$0.00	$223,051.85
CITE				0	$0.00	$0.00	$0.00
COBB				699	$36,805.00	$0.00	$36,805.00
CONS				11334	$758,758.47	$0.00	$758,758.47
DTE				1483	$76,819.38	$0.00	$76,819.38
DECA				150	$10,750.00	$0.00	$10,750.00
EKPC				375	$9,600.00	$0.00	$9,600.00
FORT				10691	$713,413.00	$0.00	$713,413.00
IMEA				0	$0.00	$0.00	$0.00
IMPA				0	$0.00	$0.00	$0.00
KCPL				0	$0.00	$0.00	$0.00
LMBE				0	$0.00	$0.00	$0.00
MECM				1025	$68,225.00	$0.00	$68,225.00
OVEC				0	$0.00	$0.00	$0.00
OMU				0	$0.00	$0.00	$0.00
SOUT				1703	$105,520.22	$0.00	$105,520.22
SEMP				0	$0.00	$0.00	$0.00
SEPA	(OMU)			31	$1,779.40	$0.00	$1,779.40
TEA				125	$8,200.00	$0.00	$8,200.00
TPS				0	$0.00	$0.00	$0.00
TAEI				0	$0.00	$0.00	$0.00
TVA				0	$0.00	$0.00	$0.00
WESC				0	$0.00	$0.00	$0.00
WSTR				328	$21,604.00	$0.00	$21,604.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended June 30, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	45848	$2,960,422.81	$0.00	$2,960,422.81

Note> LEM total will be broken out between different management reporting segments within reconciliation section below 90%

INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	315145		$6,118,826.42	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load (Includes displaced KU gen and purchases)			$441,642.61	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	15	$947.42		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	902	$58,932.95		OSS
			315,445	$6,560,469.03
			917	$59,880.37
TOTAL	316362	$6,620,349.40	316,362	6,620,349.40

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG		price change	May 07	0	$5.16	$0.00	$5.16
	0	0		0	$0.00	$0.00	$0.00
	0	0		0	$0.00	$0.00	$0.00
	0	0		0	$0.00	$0.00	$0.00
	0	0		0		$0.00	$0.00
				0		$0.00	$0.00
TOTAL				0	$5.16	$0.00	$5.16

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Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended June 30, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS	MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)	0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)			$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU	0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)	0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS	0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of May 07 Billing	0	($174,878.57)	($155,171.29)	($330,049.86)
OVEC	True-up of May 07 Billing	0	$1,237.83	($592,623.14)	($591,385.31)
OVEC		0	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($173,640.74)	($747,794.43)	($921,435.17)

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended July 31, 2007

PRE-MERGER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU			$24.26231903	129,951	$3,152,912.62	$1,470,000.00	$4,622,912.62
OVEC	SURPLUS			29,211	$612,496.25	$640,136.51	$1,252,632.76
TOTAL PREMERGER PURCHASES				159,162	$3,765,408.87	$2,110,136.51	$5,875,545.38

OTHER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	1505	77,218.90	1687	$90,967.45	$0.00	$90,967.45
MCRS	OSS	182	13,748.55	222	$22,093.77	$0.00	$22,093.77
AECI				0	$0.00	$0.00	$0.00
AEP				1417	$80,137.29	$0.00	$80,137.29
BP				0	$0.00	$0.00	$0.00
CARG				700	$42,800.00	$0.00	$42,800.00
CITI				0	$0.00	$0.00	$0.00
COBB				0	$0.00	$0.00	$0.00
CONS				449	$21,934.00	$0.00	$21,934.00
DTE				0	$0.00	$0.00	$0.00
DUCA				0	$0.00	$0.00	$0.00
EKPC				0	$0.00	$0.00	$0.00
FORT				1675	$93,482.55	$0.00	$93,482.55
IMEA				0	$0.00	$0.00	$0.00
IMPA				0	$0.00	$0.00	$0.00
KCPL				0	$0.00	$0.00	$0.00
LMBL				0	$0.00	$0.00	$0.00
MECM				0	$0.00	$0.00	$0.00
OVEC				0	$0.00	$0.00	$0.00
OMU				0	$0.00	$0.00	$0.00
PROG				0	$0.00	$0.00	$0.00
SEMP				0	$0.00	$0.00	$0.00
TEA	(OMU)			0	$0.00	$0.00	$0.00
TVA				0	$0.00	$0.00	$0.00
WESC				0	$0.00	$0.00	$0.00
WSTR				0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended July 31, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	6150	$351,415.06	$0.00	$351,415.06

Note> LEM total will be broken out between different management reporting segments within reconciliation section below

INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	285676		$5,354,023.99	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$557,269.61	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	0	$0.00		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	66	$3,858.45		OSS
			285,676	$5,911,293.60
			66	$3,858.45
TOTAL	285742	$5,915,152.05	285,742	$5,915,152.05

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS			MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	hare	0	$630.03	$0.00	$630.03
0	0		0	$0.00	$0.00	$0.00
0	0		0	$0.00	$0.00	$0.00
0	0		0	$0.00	$0.00	$0.00
0	0		0		$0.00	$0.00
			0		$0.00	$0.00
TOTAL			0	$630.03	$0.00	$630.03

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Purchased Power Energy and Demand for the Month Ended July 31, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS	MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)	0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)			$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU	0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)	0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS	0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Jan 07 Billing	0	$107,879.54	$7,541.65	$115,421.19
OVLC	True-up of Jun 07 Billing	0	($275.64)	($500,959.54)	($501,235.18)
OVEC		0	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$107,603.90	($493,417.89)	($385,813.99)

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended Aug 31, 2007

PRE-MERGER PURCHASES			MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU		$24.25097399	115,710	$2,806,080.20	$1,344,900.00	$4,150,980.20
OVEC	SURPLUS		30,199	$633,212.63	$640,136.76	$1,273,349.39
TOTAL PREMERGER PURCHASES			145,909	$3,439,292.83	$1,985,036.76	$5,424,329.59

OTHER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	27784	0.84115	1,815,172.29		27853	$1,822,073.24	$0.00	$1,822,073.24
MCRS	OSS	69	0.00209	6,900.95		1541	$192,115.99	$0.00	$192,115.99
PJM						5	$302.45	$0.00	$302.45
AECI						5555	$447,820.79	$16,275.00	$464,095.79
AEP						3003	$233,158.58	$0.00	$233,158.58
CARG						3968	$245,467.00	$0.00	$245,467.00
CTII						0	$0.00	$0.00	$0.00
COBB						0	$0.00	$0.00	$0.00
CONS						6202	$664,182.99	$0.00	$664,182.99
DTE						100	$6,300.00	$0.00	$6,300.00
DECA						0	$0.00	$0.00	$0.00
EKPC						1237	$96,580.00	$0.00	$96,580.00
FORT						1435	$139,569.61	$0.00	$139,569.61
IMEA						0	$0.00	$0.00	$0.00
IMPA						0	$0.00	$0.00	$0.00
KCPL						9	$810.00	$0.00	$810.00
IMBL		EM Acctg subsequently recorded in JE#137				249	$16,137.90	$0.00	$16,137.90
MLCM						801	$105,129.00	$0.00	$105,129.00
OVEC						0	$0.00	$0.00	$0.00
OMU						0	$0.00	$0.00	$0.00
PROG						800	$81,700.00	$0.00	$81,700.00
SEMP						0	$0.00	$0.00	$0.00
TEA						1359	$152,925.00	$0.00	$152,925.00
TAL F						763	$99,160.25	$0.00	$99,160.25
TVA						1295	$168,350.00	$0.00	$168,350.00
WESC						0	$0.00	$0.00	$0.00
WSTR						926	$102,879.98	$0.00	$102,879.98

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended Aug 31, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	57101	$4,574,662.78	$16,275.00	$4,590,937.78	
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				88%	
INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST		
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	240042		$7,200,912.50	NL	
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$447,282.68	NL	
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	4	$565.19		OSS	
LGE GEN. TO KU FOR KU PREMERGER SALES	0	$0.00		OSS	
			240,042	$7,648,195.18	
			4	$565.19	
TOTAL	240046	$7,648,760.37	240,046	$7,648,760.37	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG		price change	Jul 07	0	$775.84	$0.00	$775.84
OMU (SEPA)		offset Non-L gen 4-8-07 adjustment		(1)	($57.40)	$0.00	($57.40)
	0	0		0	$0.00	$0.00	$0.00
	0	0		0	$0.00	$0.00	$0.00
	0	0		0		$0.00	$0.00
				0		$0.00	$0.00
TOTAL				(1)	$718.44	$0.00	$718.44

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended Aug 31, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Jul 07 Billing	0	($156,009.00)	($180,162.77)	($336,171.77)
OVEC	True-up of Jul 07 Billing	0	$24,299.84	($563,493.73)	($539,193.89)
OVEC		0	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($131,709.16)	($743,656.50)	($875,365.66)

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended September 30, 2007

PRE-MERGER PURCHASES			MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU		$25.23080497	114,377	$2,885,823.78	$1,338,200.00	$4,224,023.78
OVEC	SURPLUS		29,387	$616,186.62	$619,502.17	$1,235,688.79
TOTAL PREMERGER PURCHASES			143,764	$3,502,010.40	$1,957,702.17	$5,459,712.57

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	10106	0.81539	572,027.42	10427	$590,213.36	$0.00	$590,213.36
MCRS	OSS	321	0.02590	18,185.94	73	$7,258.31	$0.00	$7,258.31
PJM					0	$0.00	$0.00	$0.00
AECI					1241	$81,341.67	$0.00	$81,341.67
AEP					2169	$119,357.28	$0.00	$119,357.28
AMEM					1304	$69,112.00	$0.00	$69,112.00
CARG					1152	$65,135.79	$0.00	$65,135.79
CITI					93	$5,115.00	$0.00	$5,115.00
COBB					0	$0.00	$0.00	$0.00
CONS					1329	$74,124.36	$0.00	$74,124.36
DTE					0	$0.00	$0.00	$0.00
DECA					1800	$109,150.00	$0.00	$109,150.00
EKPC					50	$3,000.00	$0.00	$3,000.00
FORT					1694	$115,779.92	$0.00	$115,779.92
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL	Imbalance Split tab				79	$3,368.03	$0.00	$3,368.03
MLCM					101	$5,656.00	$0.00	$5,656.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
PROG					26	$1,426.37	$0.00	$1,426.37
SEMP					0	$0.00	$0.00	$0.00
TEA					48	$3,120.00	$0.00	$3,120.00
TPS					0	$0.00	$0.00	$0.00
TAUT					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended September 30, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	21586	$1,253,158.09	$0.00	$1,253,158.09
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				84%
INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	209708		$4,187,546.89	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$309,311.33	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer.(INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	727	$43,095.60		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	651	$38,947.97		OSS
			209,708	$4,496,858.22
			1,378	$82,043.57
TOTAL	211086	$4,578,901.79	211,086	$ 4,578,901.79

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price chan	NL	Aug-07	0	$4,975.64	$0.00	$4,975.64
MCRSG	price chan	OSS	Aug-07	0	$6.33	$0.00	$6.33
TOTAL				0	$4,981.97	$0.00	$4,981.97

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended September 30, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Aug 07 Billing	0	$100,345.48	($7,802.28)	$92,543.20
OVEC	True-up of Aug 07 Billing	0	$24,344.78	($531,849.86)	($507,505.08)
OVEC	Adjustment for Jun 07	0	($2.66)	$0.00	($2.66)
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$124,687.60	($539,652.14)	($414,964.54)

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended October 31, 2007

PRE-MERGER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU					$23.37881001	130,404	$3,048,690.34	$1,293,200.00	$4,341,890.34
OVEC	SURPLUS					27,079	$567,792.47	$640,133.62	$1,207,926.09
TOTAL PREMERGER PURCHASES						157,483	$3,616,482.81	$1,933,333.62	$5,549,816.43

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	4988	0.70313	325,242.37	5205	$342,316.45	$0.00	$342,316.45
MCRS	OSS	217	0.03059	17,074.08	0	$926.27	$0.00	$926.27
PJM					0	$0.00	$0.00	$0.00
AECI					198	$12,576.00	$0.00	$12,576.00
AEP					2116	$129,794.08	$0.00	$129,794.08
CARG					353	$22,590.21	$0.00	$22,590.21
CITI					0	$0.00	$0.00	$0.00
COBB					735	$37,402.00	$0.00	$37,402.00
CONS					170	$9,354.75	$0.00	$9,354.75
DTE					50	$3,350.00	$0.00	$3,350.00
EKPC					100	$4,650.00	$0.00	$4,650.00
FORT					1300	$82,100.00	$0.00	$82,100.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					37	$3,032.25	$0.00	$3,032.25
MLCM					231	$14,134.00	$0.00	$14,134.00
NIPS					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SOUT					186	$27,543.77	$0.00	$27,543.77
SEMP					0	$0.00	$0.00	$0.00
TEA					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended October 31, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	10690	$689,769.78	$0.00	$689,769.78
				73%

Note> LEM total will be broken out between different management reporting segments within reconciliation section below

INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	303425		$5,834,589.31	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$691,372.08	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	12	$652.43		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	351	$22,925.46		OSS
			303,425	$6,525,961.39
			363	$23,577.89
TOTAL	303788	$6,549,539.28	303,788	$ 6,549,539.28

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price chan	NL	Sep-07	0	$4.84	$0.00	$4.84
MCRSG	price chan	OSS	Sep-07	0	$12.91	$0.00	$12.91
TOTAL				0	$17.75	$0.00	$17.75

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended October 31, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS		0	$0.00	$0.00	$0.00
PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Sep 07 Billing	0	$74,131.13	($46,967.10)	$27,164.03
OVEC	True-up of Sep 07 Billing	0	$20,520.79	($312,810.03)	($292,289.24)
OVEC		0	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$94,651.92	($359,777.13)	($265,125.21)

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended November 30, 2007

PRE-MERGER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU				$26.43185003	102,436	$2,707,572.99	$1,279,200.00	$3,986,772.99
OVEC	SURPLUS				30,678	$643,256.30	$619,491.67	$1,262,747.97
TOTAL PREMERGER PURCHASES					133,114	$3,350,829.29	$1,898,691.67	$5,249,520.96

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	17729	0.80936	865,256.82	18908	$964,526.67	$0.00	$964,526.67
MCRS	OSS	1179	0.05382	99,269.85	260	$25,956.01	$0.00	$25,956.01
PJM					2491	$133,009.69	$0.00	$133,009.69
AECI					1542	$89,234.01	$0.00	$89,234.01
AEP					4420	$253,304.77	$0.00	$253,304.77
CARG					4377	$273,544.00	$0.00	$273,544.00
CITI					22	$1,342.00	$0.00	$1,342.00
COBB					175	$9,500.00	$0.00	$9,500.00
CONS					1381	$87,050.90	$0.00	$87,050.90
DTE					297	$20,396.00	$0.00	$20,396.00
DECA					384	$27,648.00	$0.00	$27,648.00
EKPC					402	$24,120.79	$0.00	$24,120.79
FORT					1533	$88,107.47	$0.00	$88,107.47
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
MLCM					419	$30,942.10	$0.00	$30,942.10
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SEMP					0	$0.00	$0.00	$0.00
TEA					720	$48,273.57	$0.00	$48,273.57
TVA					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended November 30, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	37331	$2,076,955.98	$0.00	$2,076,955.98
				84%

Note> LEM total will be broken out between different management reporting segments within reconciliation section below

INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	363473		$6,050,402.87	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$614,233.08	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	0	$0.00		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	616	$33,044.37		OSS

363,473	$6,664,635.95
616	$33,044.37
364,089	$ 6,697,680.32

	MWH	INC COST
TOTAL	364089	$6,697,680.32

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price chan	NL	Oct-07	0	$0.00	$0.00	$0.00
MCRSG	price chan	OSS	Oct-07	0	$19.58	$0.00	$19.58
TOTAL				0	$19.58	$0.00	$19.58

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended November 30, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS	MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)	0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)			$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU	0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)	0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS	0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Oct 07 Billing	0	$53,152.14	($14,398.77)	$38,753.37
OVEC	True-up of Oct 07 Billing	0	($11,568.33)	($483,334.38)	($494,902.71)
OVEC		0	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$41,583.81	($497,733.15)	($456,149.34)

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended December 31, 2007

PRE-MERGER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU					$34.20252297	69,775	$2,386,481.04	$1,328,200.00	$3,714,681.04
OVEC	SURPLUS					31,274	$655,753.23	$640,136.55	$1,295,889.78
TOTAL PREMERGER PURCHASES						101,049	$3,042,234.27	$1,968,336.55	$5,010,570.82

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	2041	0.78289	113,129.83	2079	$115,777.25	$0.00	$115,777.25
MCRS	OSS	38	0.01458	2,647.42	154	$16,948.29	$0.00	$16,948.29
PJM					1525	$71,197.47	$0.00	$71,197.47
AECI					388	$26,256.00	$0.00	$26,256.00
AEP					2144	$141,264.89	$0.00	$141,264.89
CARG					1164	$80,839.81	$0.00	$80,839.81
CITI					0	$0.00	$0.00	$0.00
COBB					0	$0.00	$0.00	$0.00
CONS					525	$36,500.00	$0.00	$36,500.00
DTE					0	$0.00	$0.00	$0.00
EKPC					50	$1,600.00	$0.00	$1,600.00
FORT					0	$0.00	$0.00	$0.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
MLCM					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SEMP					0	$0.00	$0.00	$0.00
TEA					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended December 31, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	8029	$490,383.71	$0.00	$490,383.71
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				84%
INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	511119		$8,025,570.23	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$884,250.81	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	0	$0.00		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	2	$43.96		OSS
			511,119	$8,909,821.04
			2	$43.96
TOTAL	511121	$8,909,865.00	511,121	$ 8,909,865.00

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price chan	NI	Nov-07	0	$700.58	$0.00	$700.58
MCRSG	price chan	OSS	Nov-07	0	$12.45	$0.00	$12.45
MISO		0	Sep-05	0	$6.82	$0.00	$6.82
EKPC	price chan	NI	Nov-07	0	$8,618.78	$0.00	$8,618.78
EKPC	price chan	OSS	Nov-07	0	($128.16)	$0.00	($128.16)
CONSTELL	decrease n	0	Nov-07	(2)	($73.93)	$0.00	($73.93)
EKPC	acer imbal	NI	Mar-07	130	$7,800.00	$0.00	$7,800.00
TOTAL				128	$16,936.54	$0.00	$16,936.54

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended December 31, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS	MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)	0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)			$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU	0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)	0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS	0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True up of Nov 07 Billing	0	$203,292.35	$48,725.64	$252,017.99
OVEC	True-up of Nov 07 Billing	0	($13,161.66)	($549,272.92)	($562,434.58)
OVEC		0	$0.00	$0.00	$0.00
OMU	True-up of Jul07 NOx tonnage	0	$685.00	$0.00	$685.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$190,815.69	($500,547.28)	($309,731.59)

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended January 31, 2008

PRE-MERGER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU					$28.36532898	99,929	$2,834,518.96	$1,278,200.00	$4,112,718.96
OVEC	SURPLUS					36,119	$757,343.19	$722,441.48	$1,479,784.67
TOTAL PREMERGER PURCHASES						136,048	$3,591,862.15	$2,000,641.48	$5,592,503.63

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	12087	0.99391	720,179.87	12092	$720,420.36	$0.00	$720,420.36
MCRS	OSS	5	0.00041	240.49	40	$4,089.89	$0.00	$4,089.89
PJM					10925	$743,723.13	$0.00	$743,723.13
AECI					2652	$190,890.00	$0.00	$190,890.00
AEP					3292	$246,771.89	$0.00	$246,771.89
CARG					4049	$286,710.46	$0.00	$286,710.46
CITI					0	$0.00	$0.00	$0.00
COBB					829	$61,032.86	$0.00	$61,032.86
CONS					384	$25,170.00	$0.00	$25,170.00
DTE					0	$0.00	$0.00	$0.00
DECA					1000	$75,050.00	$0.00	$75,050.00
EKPC					0	$0.00	$0.00	$0.00
FORT					125	$10,475.00	$0.00	$10,475.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
KCPL					0	$0.00	$0.00	$0.00
IMBL					8	$650.64	$0.00	$650.64
MLCM					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SOUT					1100	$80,300.00	$0.00	$80,300.00
TEA					0	$0.00	$0.00	$0.00
TALT					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended January 31, 2008

TOTAL PURCHASES OTHER THAN PREMERGER	36496	$2,445,284.23	$0.00	$2,445,284.23
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				94%
INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	541939		$9,765,270.15	NI
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load (Includes displaced KU gen and purchases)			$1,005,274.97	NI
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer.(INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	0	$0.00		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	0	$0.00		OSS
			541,939	$10,770,545.12
			-	$0.00
TOTAL	541939	$10,770,545.12	541,939	$10,770,545.12

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Dec-07 Tier 2 pric NI-555015 (Enter as 1 total & rec	0	($11.20)	$0.00	($11.20)
MCRSG	Dec-07 Tier 2 pric OSS-555010	0	($1.04)	$0.00	($1.04)
MISO	0	0		$0.00	$0.00
EKPC	Nov-07 price chan NI	0		$0.00	$0.00
EKPC	Nov-07 price chan OSS	0		$0.00	$0.00
				$0.00	$0.00
				$0.00	$0.00
TOTAL		0	($12.24)	$0.00	($12.24)

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended January 31, 2008

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Dec 07 Billing	0	($22,291.92)	($50,173.68)	($72,465.60)
OVEC	True-up of Dec 07 Billing	0	$19,187.78	($500,341.19)	($481,153.41)
OVEC		0	$0.00	$0.00	$0.00
				$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($3,104.14)	($550,514.87)	($553,619.01)

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended February 29, 2008

PRE-MERGER PURCHASES			MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU		$26.54406298	123,717	$3,283,951.84	$1,367,000.00	$4,650,951.84
OVEC	SURPLUS		27,273	$571,860.26	$652,224.48	$1,224,084.74
TOTAL PREMERGER PURCHASES			150,990	$3,855,812.10	$2,019,224.48	$5,875,036.58

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	43222	0.89294	2,697,873.78	43242	$2,699,902.58	$0.00	$2,699,902.58
	OSS	20	0.00041	2,028.80	200	$23,596.27	$0.00	$23,596.27
MCRS					37464	$2,406,342.86	$0.00	$2,406,342.86
PJM					1297	$91,225.00	$0.00	$91,225.00
AECI					4248	$284,249.00	$0.00	$284,249.00
AEP					75	$5,025.00	$0.00	$5,025.00
AMEM					2910	$178,800.00	$0.00	$178,800.00
CARG					0	$0.00	$0.00	$0.00
CITI					1119	$84,273.00	$0.00	$84,273.00
COBB					3420	$246,820.00	$0.00	$246,820.00
CONS					200	$9,600.00	$0.00	$9,600.00
DTE					0	$0.00	$0.00	$0.00
EKPC					744	$56,850.00	$0.00	$56,850.00
FORT					0	$0.00	$0.00	$0.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					100	$7,500.00	$0.00	$7,500.00
SOUT					666	$45,656.00	$0.00	$45,656.00
TEA					451	$28,004.00	$0.00	$28,004.00
TVA					0	$0.00	$0.00	$0.00
WSTR								

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended February 29, 2008

TOTAL PURCHASES OTHER THAN PREMERGER	96136	$6,167,843.71	$0.00	$6,167,843.71	
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				90%	
INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST		
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	359429		$7,073,607.83	NL	
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)			$451,374.89	NL	
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer.(INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	0	$0.00		OSS	
LGE GEN. TO KU FOR KU PREMERGER SALES	5	$430.98		OSS	
			359,429	$7,524,982.72	
			5	$430.98	
TOTAL	359434	$7,525,413.70	359,434	$7,525,413.70	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Jan-08 Tier 2 pric	NL-555015	(Enter as 1 total & rec	0	$442.54	$0.00	$442.54
MCRSG	Jan-08 Tier 2 pric	OSS-555010		0	$41.30	$0.00	$41.30
MISO		0		0		$0.00	$0.00
EKPC	Nov-07 price chan	NL		0		$0.00	$0.00
EKPC	Nov-07 price chan	OSS		0		$0.00	$0.00
PJM	Jan-08 Volume in	0		0	$7.32	$0.00	$7.32
						$0.00	$0.00
TOTAL				0	$491.16	$0.00	$491.16

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended February 29, 2008

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Jan 08 Billing	0	($62,346.91)	($88,261.26)	($150,608.17)
OVEC	True-up of Jan 08 Billing	0	($60,159.69)	($186,706.07)	($246,865.76)
OVEC		0	$0.00	$0.00	$0.00
				$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($122,506.60)	($274,967.33)	($397,473.93)

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended March 31, 2008

PRE-MERGER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU					$96.13065109	16,603	$1,596,057.20	$1,356,772.00	$2,952,829.20
OVEC	SURPLUS					31,230	$654,830.64	$723,545.13	$1,378,375.77
TOTAL PREMERGER PURCHASES						47,833	$2,250,887.84	$2,080,317.13	$4,331,204.97

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	28001	0.85190	1,883,789.47	29491	$2,035,976.84	$0.00	$2,035,976.84
MCRS	OSS	1490	0.04533	152,187.37	765	$86,521.91	$0.00	$86,521.91
PJM					39070	$2,711,653.22	$0.00	$2,711,653.22
AECI					0	$0.00	$0.00	$0.00
AEP					1160	$87,199.77	$0.00	$87,199.77
AMEM					500	$32,500.00	$0.00	$32,500.00
CARG					2199	$181,291.24	$0.00	$181,291.24
CITI					100	$8,500.00	$0.00	$8,500.00
COBB					0	$0.00	$0.00	$0.00
CONS					75	$6,750.00	$0.00	$6,750.00
DTE					100	$7,200.00	$0.00	$7,200.00
EKPC					0	$0.00	$0.00	$0.00
FORT					450	$34,400.00	$0.00	$34,400.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
BREC					31	$2,866.52	$0.00	$2,866.52
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
TEA					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
XLWO					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended March 31, 2008

TOTAL PURCHASES OTHER THAN PREMERGER	73941	$5,194,859.50	$0.00	$5,194,859.50	
				88%	

Note> LEM total will be broken out between different management reporting segments within reconciliation section below

INTERCOMPANY PURCHASE	MWH	INC COST	FUEL COST		
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)	399298		$7,106,079.82		NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load (Includes displaced KU gen and purchases)			$1,367,924.34		NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	399	$32,953.65			OSS
LGE GEN. TO KU FOR KU PREMERGER SALES	1668	$55,363.51			OSS
			399,298	$8,474,004.16	
			2,067	$88,317.16	
TOTAL	401365	$8,562,321.32	401,365	$8,562,321.32	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Feb-08 Tier 2 pric NL-555015 (Enter as 1 total & rec	0	$75.74	$0.00	$75.74
MCRSG	Feb-08 Tier 2 pric OSS-555010	0	$7.07	$0.00	$7.07
MISO	0	0		$0.00	$0.00
EKPC	Feb-08 price chan NL	0		$0.00	$0.00
EKPC	Feb-08 price chan OSS	0	$162.73	$0.00	$162.73
PJM	Feb-08 Volume in 0			$0.00	$0.00
TOTAL		0	$245.54	$0.00	$245.54

KENTUCKY UTILITIES

Case No. 2007-00565
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Purchased Power Energy and Demand for the Month Ended March 31, 2008

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Feb 08 Billing	0	$392,586.56	($10,193.07)	$382,393.49
OMU	Error Correction from Jan 08		$124,693.82	$176,522.52	$301,216.34
OVEC	True-up of Feb 08 Billing	0	$4,495.11	($164,592.85)	($160,097.74)
OVEC	True-up of December 07 Billing	0	$0.00	$358,325.16	$358,325.16
				$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$521,775.49	$360,061.76	$881,837.25

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended April 30, 2008

PRE-MERGER PURCHASES			MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OMU		$102.94237878	15,159	$1,560,503.52	$1,372,722.68	$2,933,226.20
OVEC	SURPLUS		30,997	$649,945.10	$699,143.69	$1,349,088.79
TOTAL PREMERGER PURCHASES			46,156	$2,210,448.62	$2,071,866.37	$4,282,314.99

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	NL	34175	0.94048	2,298,744.98	36009	$2,488,120.76	$0.00	$2,488,120.76
MCRS	OSS	1834	0.05047	189,375.78	0	$0.00	$0.00	$0.00
PJM					32854	$2,517,654.88	$0.00	$2,517,654.88
AECI					773	$56,456.00	$0.00	$56,456.00
AEP					1000	$83,350.00	$0.00	$83,350.00
AMEM					150	$13,500.00	$0.00	$13,500.00
CARG					691	$59,721.51	$0.00	$59,721.51
CITI					0	$0.00	$0.00	$0.00
COBB					288	$21,255.00	$0.00	$21,255.00
CONS					814	$63,678.99	$0.00	$63,678.99
DECA					0	$0.00	$0.00	$0.00
EKPC					0	$0.00	$0.00	$0.00
FORT					800	$72,000.00	$0.00	$72,000.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					589	$42,680.02	$0.00	$42,680.02
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$8.13	$8.13
TEA					2336	$199,552.00	$0.00	$199,552.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended April 30, 2008

TOTAL PURCHASES OTHER THAN PREMERGER		76304	$5,617,969.16	$8.13	$5,617,977.29
Note> LEM total will be broken out between different management reporting segments within reconciliation section below					99%
INTERCOMPANY PURCHASE		MWH	INC COST	FUEL COST	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU) KU purchase of LGE gen at fuel cost (INTERNAL ECONOMY)		349706		$5,972,458.34	NL
SPLIT SAVINGS (KU TO LGE RATE BASE) One half the difference between LGE gen (fuel) sent to KU and the displaced KU source which would have been used to supply the KU local load. (Includes displaced KU gen and purchases)				$653,418.45	NL
PURCHASE OF FREED UP LGE GEN BACK TO KU Purchase back of the portion of Gen freed up at LGE by the Intercompany transfer (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)		0	$0.00		OSS
LGE GEN. TO KU FOR KU PREMERGER SALES		516	$42,405.41		OSS
				349,706	$6,625,876.79
				516	$42,405.41
TOTAL		350222	$6,668,282.20	350,222	$ 6,668,282.20

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Mar-08 Tier 2 pric NL-555015 (Enter as 1 total & rec	0	$825.77	$0.00	$825.77
MCRSG	Mar-08 Tier 2 pric OSS-555010	0	$151.21	$0.00	$151.21
MISO	0	0		$0.00	$0.00
EKPC	Feb-08 price chan NL	0		$0.00	$0.00
EKPC	Feb-08 price chan OSS	0		$0.00	$0.00
PJM	Feb-08 Volume in 0	0	$0.00	$0.00	$0.00
				$0.00	$0.00
TOTAL		0	$976.98	$0.00	$976.98

KENTUCKY UTILITIES

Case No. 2007-00565
Case No. 2008-00251

Purchased Power Energy and Demand for the Month Ended April 30, 2008

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
LGE GEN FOR KU NATIVE LOAD (LGE SALE TO KU)		0	$0.00		
SPLIT SAVINGS (KU TO LGE RATE BASE)				$0.00	
PURCHASE OF FREED UP LGE GEN BACK TO KU		0	$0.00		
LGE GEN. TO KU FOR KU PREMERGER SALES (LGE SALE TO KU)		0	$0.00		
TOTAL INTERCOMPANY PURCH ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$0.00	$0.00	$0.00
OMU	True-up of Mar 08 Billing	0	($8,082.26)	$15,977.04	$7,894.78
OMU			$0.00	$0.00	$0.00
OVEC	True-up of Mar 08 Billing	0	($18,868.00)	($107,916.48)	($126,784.48)
OVEC		0	$0.00	$0.00	$0.00
				$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($26,950.26)	($91,939.44)	($118,889.70)

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. 168

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-168. With regard to KU Intercompany sales, please provide:

a. a detailed explanation along with all workpapers and analyses showing the pricing methodology (basis) and amount (units and dollars) for sales to affiliates; and,

b. if not provided in (a) above, please provide the detailed determination of test year Intercompany sales (units and dollars) by month and by affiliate.

A-168. a. Please see the response to Question Nos. 167(d), 109, and 110. The attachment to this response includes the Power Transaction Schedules from the monthly FAC Form B filings for the test year. The purchase and sales amounts (units and dollars) for intercompany transactions between KU and LG&E are contained on these schedules.

b. See part (a).

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: May 31, 2007

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	28,000		1,146.33	648.13	1,794.46
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	1,000		70.46	47.07	117.53
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	23,000		659.29	372.77	1,032.06
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	30,000		802.57	545.09	1,347.66
BP ENERGY COMPANY	BP	Economy	1,000		41.44	28.15	69.59
CARGILL- ALLIANT, LLC	CARG	Economy	20,000		563.52	382.73	946.25
CITIGROUP ENERGY, INC.	CITI	Economy	5,000		166.31	112.95	279.26
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	10,000		309.92	210.50	520.42
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	12,000		312.33	211.50	523.83
DTE ENERGY TRADING, INC.	DTE	Economy	1,000		33.30	22.62	55.92
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	2,000		57.23	38.87	96.10
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	17,000		492.81	334.70	827.51
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	1,000		35.21	23.92	59.13
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	1,000		35.95	24.41	60.36
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	14,000		383.68	260.59	644.27
PROGRESS ENERGY VENTURES INC.	PROG	Economy	3,000		88.43	60.06	148.49
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	2,000		55.41	37.64	93.05
THE ENERGY AUTHORITY	TEA	Economy	1,000		26.27	17.84	44.11
TENNESSEE VALLEY AUTHORITY	TVA	Economy	13,000		379.00	257.41	636.41
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	10,000		283.26	192.39	475.65
WESTAR ENERGY, INC.	WSTR	Economy	1,000		30.61	20.79	51.40
MISCELLANEOUS					57.40	(57.40)	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	107,000	0	8,652.14	756.15	9,408.29
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	10.00	10.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	86,015,000		2,161,668.28	712,561.99	2,874,230.27
TOTAL			86,318,000	0	2,176,351.15	717,120.87	2,893,472.02

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: June 30, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	309,000		9,223.96	6,588.46	15,812.42
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	14,000		895.56	738.62	1,634.18
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	174,000		4,652.41	3,323.10	7,975.51
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	418,000		12,464.42	8,903.06	21,367.48
BP ENERGY COMPANY	BP	Economy	6,000		239.26	195.44	434.70
CARGILL- ALLIANT, LLC	CARG	Economy	225,000		6,041.78	4,315.50	10,357.28
CITIGROUP ENERGY, INC.	CITI	Economy	26,000		786.57	561.83	1,348.40
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	207,000		6,748.19	4,820.08	11,568.27
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	646,000		19,533.28	13,952.25	33,485.53
DTE ENERGY TRADING, INC.	DTE	Economy	49,000		1,166.79	833.42	2,000.21
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	226,000		8,964.01	6,402.80	15,366.81
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	193,000		5,541.83	3,958.40	9,500.23
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	158,000		6,561.41	4,686.67	11,248.08
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	105,000		4,962.74	3,544.77	8,507.51
KANSAS CITY POWER & LIGHT	KCPL	Economy	65,000		2,105.97	1,504.26	3,610.23
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	120,000		3,601.17	2,565.11	6,166.28
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	101,000		3,176.14	2,268.65	5,444.79
THE ENERGY AUTHORITY	TEA	Economy	232,000		7,809.01	5,577.81	13,386.82
TENASKA POWER SERVICES CO.	TPS	Economy	24,000		546.52	397.49	944.01
TRANSALTA ENERGY MARKETING (U.S.) INC.	TALT	Economy	4,000		107.58	87.87	195.45
TENNESSEE VALLEY AUTHORITY	TVA	Economy	603,000		16,772.50	11,980.21	28,752.71
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	6,000		126.25	103.99	230.24
WESTAR ENERGY, INC.	WSTR	Economy	11,000		287.82	235.11	522.93
MISCELLANEOUS					5.16	(5.16)	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	4,821,000	-	283,175.51	26,063.77	309,239.28
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	8,216.00	8,216.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	86,951,000		2,153,158.88	740,761.09	2,893,919.97
TOTAL			95,694,000	0.00	2,558,654.72	862,580.60	3,421,235.32

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: July 31, 2007

Company		Type of Transaction	KWH	Billing Components Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	272,000		8,863.54	7,100.32	15,963.86
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	10,000		581.61	483.85	1,065.46
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	78,000		1,982.75	1,588.45	3,571.20
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	440,000		11,933.27	9,560.18	21,493.45
BP ENERGY COMPANY	BP	Economy	6,000		169.96	141.16	311.12
CARGILL- ALLIANT, LLC	CARG	Economy	244,000		6,207.89	4,973.38	11,181.27
CITIGROUP ENERGY, INC.	CITI	Economy	15,000		479.52	398.29	877.81
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	61,000		1,487.19	1,235.24	2,722.43
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	407,000		10,869.36	8,707.84	19,577.20
DTE ENERGY TRADING, INC.	DTE	Economy	17,000		606.68	503.89	1,110.57
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	35,000		686.68	570.35	1,257.03
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	115,000		4,598.73	3,684.20	8,282.93
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	398,000		10,965.90	8,785.20	19,751.10
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	67,000		2,011.29	1,670.54	3,681.83
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	71,000		2,133.49	1,772.05	3,905.54
KANSAS CITY POWER & LIGHT	KCPL	Economy	19,000		752.32	624.87	1,377.19
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	97,000		3,017.10	2,505.95	5,523.05
PROGRESS ENERGY VENTURES INC.	PROG	Economy	23,000		712.26	591.60	1,303.86
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	150,000		4,360.41	3,493.30	7,853.71
THE ENERGY AUTHORITY	TEA	Economy	78,000		2,382.68	1,979.01	4,361.69
TENNESSEE VALLEY AUTHORITY	TVA	Economy	309,000		8,150.15	6,529.37	14,679.52
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	6,000		177.95	147.80	325.75
WESTAR ENERGY, INC.	WSTR	Economy	5,000		116.75	96.95	213.70
MISCELLANEOUS					630.03	(630.03)	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	642,000	-	34,068.22	2,996.46	37,064.68
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	1,233.00	1,233.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	112,352,000		2,857,012.71	716,726.10	3,573,738.81
TOTAL			115,917,000	0.00	2,974,958.44	787,469.32	3,762,427.76

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: August 31, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components: Fuel Charges($)	Billing Components: Other Charges($)	Billing Components: Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	131000		5,144.77	3,003.56	8,148.33
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	6000		329.24	280.93	610.17
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	355000		11,731.48	6,848.95	18,580.43
CARGILL- ALLIANT, LLC	CARG	Economy	157000		4,341.68	2,534.71	6,876.39
CITIGROUP ENERGY, INC.	CITI	Economy	4000		76.47	66.95	143.42
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	60000		1,611.43	940.77	2,552.20
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	237000		5,810.96	3,392.49	9,203.45
DTE ENERGY TRADING, INC.	DTE	Economy	5000		209.20	183.16	392.36
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	221000		4,900.95	2,861.21	7,762.16
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	5000		185.82	162.69	348.51
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	81000		2,493.49	1,455.73	3,949.22
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	140000		5,388.14	3,145.64	8,533.78
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	177000		6,923.95	4,042.26	10,966.21
ENERGY IMBALANCE	IMBL	Economy	12000		724.23	422.82	1,147.05
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	53000		1,927.05	1,125.03	3,052.08
PROGRESS ENERGY VENTURES INC.	PROG	Economy	53000		2,384.67	1,392.19	3,776.86
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	112000		3,924.36	2,291.08	6,215.44
THE ENERGY AUTHORITY	TEA	Economy	37000		1,180.78	689.34	1,870.12
TENNESSEE VALLEY AUTHORITY	TVA	Economy	502000		12,138.12	7,086.35	19,224.47
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	13000		624.52	364.62	989.14
MISCELLANEOUS					718.44	(718.44)	-
LOUISVILLE GAS & ELECTRIC	LGE	Economy	45,848,000		1,432,292.19	285,380.53	1,717,672.72
TOTAL			48,209,000	0	1,505,061.94	326,952.57	1,832,014.51

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: September 30, 2007

Company		Type of Transaction	KWH	Billing Components Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR,	MISO	Economy	448,000		13,513.34	7,094.30	20,607.64
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	21,000		1,501.96	788.50	2,290.46
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	153,000		4,285.63	2,249.89	6,535.52
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	1,273,000		41,615.59	21,847.58	63,463.17
CARGILL- ALLIANT, LLC	CARG	Economy	508,000		16,987.51	8,918.19	25,905.70
CITIGROUP ENERGY, INC.	CITI	Economy	120,000		3,548.81	1,863.07	5,411.88
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	257,000		8,363.63	4,390.78	12,754.41
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	876,000		28,417.22	14,918.63	43,335.85
DTE ENERGY TRADING, INC.	DTE	Economy	9,000		334.94	175.84	510.78
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	213,000		5,793.84	3,041.68	8,835.52
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	79,000		2,558.27	1,343.05	3,901.32
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	1,226,000		36,694.70	19,264.17	55,958.87
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	1,477,000		60,539.81	31,782.50	92,322.31
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	1,572,000		64,417.16	33,818.06	98,235.22
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	176,000		7,876.11	4,134.84	12,010.95
PROGRESS ENERGY VENTURES INC.	PROG	Economy	119,000		4,095.97	2,150.32	6,246.29
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	419,000		15,218.94	7,944.23	23,163.17
THE ENERGY AUTHORITY	TEA	Economy	177,000		5,524.40	2,900.22	8,424.62
TENASKA POWER SERVICES CO.	TPS	Economy	9,000		240.43	126.23	366.66
TRANSALTA ENERGY MARKETING (U.S.) INC.	TALT	Economy	77,000		3,999.16	2,099.52	6,098.68
TENNESSEE VALLEY AUTHORITY	TVA	Economy	3,267,000		99,456.54	52,213.26	151,669.80
MISCELLANEOUS					4,981.97	(4,981.97)	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	5,585,000	-	254,921.14	26,135.63	281,056.77
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	12,627.00	12,627.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	61,148,000		1,639,273.56	326,147.86	1,965,421.42
TOTAL			79,209,000	0.00	2,324,160.63	582,993.38	2,907,154.01

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: October 31, 2007

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	1,721,000		42,612.74	40,440.71	83,053.45
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	52,000		2,826.00	2,706.64	5,532.64
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	3,216,000		88,035.01	83,676.49	171,711.50
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	431,000		9,871.12	9,382.41	19,253.53
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	750,000		18,564.45	17,645.35	36,209.80
CARGILL- ALLIANT, LLC	CARG	Economy	976,000		23,571.62	22,404.62	45,976.24
CITIGROUP ENERGY, INC.	CITI	Economy	174,000		4,481.98	4,288.15	8,770.13
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	66,000		1,607.37	1,609.75	3,217.12
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	529,000		11,967.44	11,374.95	23,342.39
DTE ENERGY TRADING, INC.	DTE	Economy	158,000		4,481.30	4,259.43	8,740.73
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	31,000		1,171.21	1,172.94	2,344.15
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	288,000		7,771.34	7,386.58	15,157.92
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	185,000		7,168.13	6,813.25	13,981.38
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	197,000		7,627.65	7,250.01	14,877.66
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	207,000		6,296.75	5,985.00	12,281.75
NO. INDIANA PUBLIC SERVICE CO.	NIPS	Economy	4,000		125.39	125.58	250.97
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	173,000		4,217.55	4,008.75	8,226.30
THE ENERGY AUTHORITY	TEA	Economy	56,000		1,387.19	1,389.24	2,776.43
TENNESSEE VALLEY AUTHORITY	TVA	Economy	1,980,000		46,178.86	43,892.60	90,071.46
WESTAR ENERGY, INC.	WSTR	Economy	6,000		155.45	155.70	311.15
MISCELLANEOUS					17.75	(17.75)	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	4,670,000	-	217,030.44	21,161.50	238,191.94
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	14,742.00	14,742.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	140,533,000		3,632,483.48	799,057.37	4,431,540.85
TOTAL			156,403,000	-	4,139,650.22	1,110,911.27	5,250,561.49

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: November 30, 2007

Company		Type of Transaction	KWH	Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
				Billing Components			
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	147,000		5,425.46	2,351.54	7,777.00
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	9,000		724.70	314.11	1,038.81
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	422,000		15,284.09	6,624.56	21,908.65
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	37,000		1,266.77	549.05	1,815.82
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	62,000		2,255.34	977.53	3,232.87
CARGILL- ALLIANT, LLC	CARG	Economy	33,000		1,221.19	529.29	1,750.48
CITIGROUP ENERGY, INC.	CITI	Economy	23,000		788.57	341.78	1,130.35
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	5,000		165.00	84.92	249.92
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	43,000		1,485.57	643.90	2,129.47
DTE ENERGY TRADING, INC.	DTE	Economy	14,000		478.32	246.17	724.49
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	-		-	-	-
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	21,000		896.62	388.62	1,285.24
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	13,000		444.97	229.00	673.97
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	73,000		3,599.46	1,560.11	5,159.57
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	73,000		842.23	365.05	1,207.28
ENERGY IMBALANCE	IMBL	Economy	-		-	-	-
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	14,000		503.40	259.07	762.47
OHIO VALLEY ELECTRIC CORPORATION	OVEC	Economy	-		-	-	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	-		-	-	-
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	6,000		231.77	119.28	351.05
THE ENERGY AUTHORITY	TEA	Economy	5,000		169.19	87.08	256.27
TENNESSEE VALLEY AUTHORITY	TVA	Economy	450,000		15,568.87	6,748.00	22,316.87
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	11,161,000	0	458,405.95	49,355.06	507,761.01
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	44,712.00	44,712.00
HOOSIER ENERGY RURAL ELECTRIC COOP.	HE	Allowances	-		-	-	-
LOUISVILLE GAS & ELECTRIC	LGE	Economy	95,107,000		2,642,920.47	558,254.25	3,201,174.72
TOTAL			107,718,000	0	3,152,697.52	674,720.79	3,827,418.31

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: December 31, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	1,966,000		41,769.98	41,510.88	83,280.86
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	41,000		2,215.95	2,291.08	4,507.03
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	5,283,000		119,129.19	118,212.51	237,341.70
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	1,569,000		35,618.31	35,344.25	70,962.56
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	739,000		17,241.01	17,108.35	34,349.36
CARGILL- ALLIANT, LLC	CARG	Economy	360,000		8,800.85	8,733.12	17,533.97
CITIGROUP ENERGY, INC.	CITI	Economy	7,000		116.24	120.18	236.42
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	202,000		4,696.44	4,660.29	9,356.73
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	658,000		15,651.23	15,530.79	31,182.02
DTE ENERGY TRADING, INC.	DTE	Economy	39,000		1,346.73	1,392.39	2,739.12
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	454,000		12,731.21	12,636.49	25,367.70
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	89,000		2,408.98	2,390.44	4,799.42
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	78,000		2,453.83	2,434.96	4,888.79
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	129,000		4,235.99	8,215.15	12,451.14
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	106,000		3,599.01	3,571.33	7,170.34
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	141,000		5,077.55	5,038.47	10,116.02
THE ENERGY AUTHORITY	TEA	Economy	20,000		609.50	630.16	1,239.66
TENNESSEE VALLEY AUTHORITY	TVA	Economy	2,058,000		47,999.07	47,629.71	95,628.78
WESTAR ENERGY, INC.	WSTR	Economy	33,000		897.12	927.53	1,824.65
MISCELLANEOUS					(182.82)	182.82	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	38,000	-	752.36	136.71	889.07
LOUISVILLE GAS & ELECTRIC	LGE	Economy	188,654,000		4,500,469.00	943,756.28	5,444,225.28
TOTAL			202,664,000	0.00	4,827,636.73	1,272,453.89	6,100,090.62

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: January 31, 2008

Company		Type of Transaction	KWH	Demand($)	Billing Components Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	4,731,000		119,222.59	88,513.33	207,735.92
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	17,000		1,073.09	796.64	1,869.73
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	3,944,000		98,149.46	72,870.45	171,019.91
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	190,000		4,813.35	3,573.38	8,386.73
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	323,000		9,420.93	6,994.01	16,414.94
CARGILL- ALLIANT, LLC	CARG	Economy	223,000		6,645.27	4,933.38	11,578.65
CITIGROUP ENERGY, INC.	CITI	Economy	12,000		350.20	276.61	626.81
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	108,000		3,093.63	2,296.67	5,390.30
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	157,000		3,699.80	2,746.01	6,445.81
DTE ENERGY TRADING, INC.	DTE	Economy	10,000		319.39	252.28	571.67
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	22,000		574.53	453.80	1,028.33
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	129,000		5,142.38	3,817.65	8,960.03
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	46,000		1,562.19	1,233.90	2,796.09
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	31,000		1,116.68	882.02	1,998.70
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	40,000		1,370.46	1,082.47	2,452.93
KANSAS CITY POWER & LIGHT	KCPL	Economy	10,000		233.09	184.10	417.19
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	42,000		1,045.91	826.12	1,872.03
THE ENERGY AUTHORITY	TEA	Economy	10,000		211.68	167.19	378.87
TRANSALTA ENERGY MARKETING (U.S.) INC.	TALT	Economy	39,000		922.59	728.71	1,651.30
TENNESSEE VALLEY AUTHORITY	TVA	Economy	892,000		24,872.30	18,464.96	43,337.26
WESTAR ENERGY, INC.	WSTR	Economy	2,000		38.24	30.20	68.44
MISCELLANEOUS					(7,801.04)	7,801.04	-
LOUISVILLE GAS & ELECTRIC	LGE	Economy	202,531,000		5,190,355.07	983,791.01	6,174,146.08
TOTAL			213,509,000	-	5,466,431.79	1,202,715.93	6,669,147.72

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: February 29, 2008

Company		Type of Transaction	KWH	Demand($)	Billing Components: Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	355,000		10,127.34	8,358.86	18,486.20
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	2,000		114.75	98.52	213.27
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	494,000		13,195.42	10,891.22	24,086.64
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	33,000		870.05	747.08	1,617.13
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	12,000		292.54	251.20	543.74
AMEREN ENERGY MARKETING COMPANY	AMEM	Economy	2,000		54.39	46.70	101.09
CARGILL- ALLIANT, LLC	CARG	Economy	14,000		371.55	319.04	690.59
CITIGROUP ENERGY, INC.	CITI	Economy	2,000		57.36	49.26	106.62
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	6,000		156.00	133.95	289.95
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	7,000		170.16	146.11	316.27
DTE ENERGY TRADING, INC.	DTE	Economy	1,000		20.79	17.85	38.64
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	4,000		135.25	116.14	251.39
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	12,000		280.76	241.07	521.83
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	1,000		27.94	23.99	51.93
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	1,000		28.22	24.24	52.46
THE ENERGY AUTHORITY	TEA	Economy	1,000		22.02	18.91	40.93
TENNESSEE VALLEY AUTHORITY	TVA	Economy	42,000		1,191.94	1,023.48	2,215.42
WESTAR ENERGY, INC.	WSTR	Economy	1,000		40.58	34.84	75.42
MISCELLANEOUS					(7,751.38)	7,751.38	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	128,000	-	10,000.15	856.97	10,857.12
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	460.00	460.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	90,222,000		2,358,094.19	422,678.62	2,780,772.81
TOTAL			91,340,000	-	2,387,500.02	454,289.43	2,841,789.45

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: March 31, 2008

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	5,543,000		199,348.88	113,332.13	312,681.01
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	61,000		4,322.51	2,457.40	6,779.91
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	5,686,000		215,605.85	122,574.39	338,180.24
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	375,000		17,458.24	9,925.21	27,383.45
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	108,000		4,270.28	2,427.69	6,697.97
AMEREN ENERGY MARKETING COMPANY	AMEM	Economy	18,000		577.56	328.36	905.92
CARGILL- ALLIANT, LLC	CARG	Economy	361,000		13,708.53	7,793.47	21,502.00
CITIGROUP ENERGY, INC.	CITI	Economy	96,000		3,951.41	2,246.42	6,197.83
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	175,000		5,789.48	3,291.38	9,080.86
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	92,000		4,012.21	2,280.99	6,293.20
DTE ENERGY TRADING, INC.	DTE	Economy	-		-	-	-
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	166,000		7,389.98	4,201.29	11,591.27
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	55,000		2,425.42	1,378.88	3,804.30
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	626,000		45,056.24	25,615.00	70,671.24
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	858,000		61,885.66	35,182.70	97,068.36
BIG RIVERS ELECTRIC CORP.	BREC	Economy	-		-	-	-
OHIO VALLEY ELECTRIC CORPORATION	OVEC	Economy	-		-	-	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	-		-	-	-
THE ENERGY AUTHORITY	TEA	Economy	97,000		3,867.33	2,198.61	6,065.94
TENNESSEE VALLEY AUTHORITY	TVA	Economy	1,966,000		63,578.03	36,144.82	99,722.85
XLWOCOST	XLWO	Economy	-		-	-	-
MISCELLANEOUS					-	-	-
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	17,504,000	-	751,572.32	91,266.86	842,839.18
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	50,508.00	50,508.00
HOOSIER ENERGY RURAL ELECTRIC COOP.	HE	Allowances	-		-	-	-
LOUISVILLE GAS & ELECTRIC	LGE	Economy	149,969,000		4,813,715.43	570,257.02	5,383,972.45
TOTAL			183,756,000	-	6,218,535.36	1,083,410.62	7,301,945.98

Kentucky Utilities Company

POWER TRANSACTION SCHEDULE

Month Ended: April 30, 2008

Company		Type of Transaction	KWH	Demand($)	Billing Components Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	4,994,000		173,052.35	122,419.39	295,471.74
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	44,000		2,770.43	2,034.20	4,804.63
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	10,355,000		346,750.03	244,652.99	591,403.02
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	322,000		12,724.05	8,979.63	21,703.68
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	252,000		8,791.41	6,204.28	14,995.69
AMEREN ENERGY MARKETING COMPANY	AMEM	Economy	49,000		2,408.59	1,723.10	4,131.69
CARGILL- ALLIANT, LLC	CARG	Economy	567,000		22,008.08	15,531.56	37,539.64
CITIGROUP ENERGY, INC.	CITI	Economy	138,000		5,706.00	4,082.05	9,788.05
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	192,000		6,343.61	4,538.19	10,881.80
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	299,000		11,875.60	8,380.85	20,256.45
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	626,000		17,946.85	12,665.46	30,612.31
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	124,000		5,784.88	4,138.48	9,923.36
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	200,000		7,906.04	5,655.95	13,561.99
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	33,000		2,268.80	1,623.10	3,891.90
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	50,000		3,369.45	2,410.50	5,779.95
THE ENERGY AUTHORITY	TEA	Economy	269,000		7,306.96	5,156.66	12,463.62
TENNESSEE VALLEY AUTHORITY	TVA	Economy	2,310,000		69,352.79	48,943.67	118,296.46
WESTAR ENERGY, INC.	WSTR	Economy	69,000		2,675.37	1,913.94	4,589.31
OWENSBORO MUNICIPAL UTILITIES	OMU	Economy	13,143,000	-	780,965.56	71,478.96	852,444.52
OWENSBORO MUNICIPAL UTILITIES	OMU	Allowances	-		-	20,768.00	20,768.00
LOUISVILLE GAS & ELECTRIC	LGE	Economy	104,301,000		2,877,022.18	355,694.33	3,232,716.51
TOTAL			138,337,000	-	4,367,029.03	948,995.29	5,316,024.32

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. 169

Responding Witness: William Steven Seelye

Q-169. With regard to Mr. Seelye's KU direct testimony, page 23, lines 13 through 18:

a. please provide all statistical studies that do and do not "indicate that temperature sensitive loads are less significant in the range of temperature between 60°F and 70°F;"
b. please provide all studies and references substantiating the statement: "cooling loads are often not significant until mean daily temperatures exceed 70°F, and heating loads are often not significant until mean daily temperatures drop below 60°F;" and,
c. please provide all studies that indicate cooling loads are not significant until mean daily temperatures exceed 70°F, and/or heating loads are not significant until mean daily temperatures drop below 60°F.

A-169. See response to Question No. 179.

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. 170

Responding Witness: William Steven Seelye

Q-170. With regard to Mr. Seelye's KU direct testimony, page 26, lines 3 and 4, should this sentence refer to "one" standard deviation, instead of "two"? If no, please reconcile with statement on lines 6 and 7 of page 26.

A-170. No. The *total* bandwidth is equal to two standard deviations centered on the mean, which comprises one standard deviation above and one standard deviation below the mean.

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. 171

Responding Witness: William Steven Seelye

Q-171. With regard to Mr. Seelye's KU direct testimony, page 25, lines 6 through 13, please provide a complete copy of the referenced Order.

A-171. See response to Question No. 176.

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. 172

Responding Witness: William Steven Seelye

Q-172. With regard to Mr. Seelye's KU direct testimony, page 35, line 15, please explain in layman's terms:

a. what F-statistic means and relates to; and,
b. why a 0.50 level of significance was selected.

In addition, please provide support and references regarding the criteria for selecting an appropriate F-statistic level of significance.

A-172. In the context of Mr. Seelye's statement on page 35, line 15 of his testimony, the F-statistic refers to the "partial F-statistic" used add or remove variables in forward, backward and stepwise regression. In very general terms, the F-statistic compares the impact of adding or removing a variable in a regression model to a confidence interval given by an F-distribution. This is the most commonly used criterion for the addition or deletion of variables in stepwise regression and is the methodology used by SAS and other statistical software packages for determining whether a variable should be retained through the application of a stepwise regression procedure. A 0.50 level of significance is the default criterion utilized by SAS. See J.D. Jobson, *Applied Multivariate Data Analysis* (New York: Springer-Verlag, 1992).

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. 173

Responding Witness: William Steven Seelye

Q-173. Regarding Mr. Seelye's KU direct testimony, page 38, lines 17 and 18, please provide all analyses, studies, and observations supporting the statement: "We have long observed that sales patterns can be different on Mondays and Fridays than other days of the week."

A-173. This is a result that Mr. Seelye and other analysts he has worked with over the years have observed in modeling electric sales. Mr. Seelye did not retain the regression and other models he worked with over the years. The data utilized in this proceeding certainly indicate that the coefficients for the dichotomous Monday and Friday variables are frequently statistically significant. See Seelye Exhibit 11.

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. 174

Responding Witness: William Steven Seelye

Q-174. Regarding Mr. Seelye's KU direct testimony, page 36, line 22 through page 37, line 4, please provide all analyses, studies, and observations supporting the statement: "For many years, my colleagues and I have noticed that using a base of 70°F for determining cooling degree days produces a better fit than using a 65°F base temperature."

A-174. This is a result that Mr. Seelye and other analysts he has worked with over the years have observed in modeling electric sales. Mr. Seelye did not retain the regression and other models he worked with over the years. The data utilized in this proceeding certainly indicate that the coefficients for the HDD60 and CDD70 Monday and Friday variables are frequently more statistically significant than HDD65 and CDD65. See Seelye Exhibit 11.

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. 175

Responding Witness: William Steven Seelye

Q-175. Regarding Mr. Seelye's KU direct testimony, page 42, lines 10 and 11, please provide support for the statement: "a typical rule is that none of the VIF's should exceed 10."

A-175. See D. A. Belsley, E. Kuh, and R.E. Welsch, *Regression Diagnostics: Identifying Influential Data and Sources of Collinearity* (New York: John Wiley & Sons, 1980), and Chong Ho Yu, "An Overview of Remedial Tools for Collinearity in SAS," *Proceedings of the 2000 Western Users of SAS Software Conference*, pp. 196-201.

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. 176

Responding Witness: William Steven Seelye

Q-176. Regarding Mr. Seelye's KU direct testimony, page 45, lines 17 through 19, please provide all references and complete Commission Orders that "expressed concerns with using billing-cycle degree days . . . for purposes of calculating the electric temperature normalization adjustment."

A-176. See the Commission's Order in Case No. 10064, which is attached.

Commission's Order in Case No. 10064
Responding Witness – William Steven Seelye

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. 10064

O R D E R

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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. 10064

O R D E R

On November 20, 1987, 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 December 20, 1987. The proposed rates would increase annual electric revenues by $37,794,000, an increase of 8.5 percent, and annual gas revenues by $12,073,000, an increase of 7.27 percent. These increases represent an annual increase in total operating revenues of $49,867,000, or 8.16 percent, based on normalized test year sales. This Order grants an increase in annual gas and electric revenues of $21,993,394 or 3.5 percent.

The Commission suspended the proposed rate increases until May 20, 1988 in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for March 22, 1988 for the purpose of cross-examination of the witnesses of LG&E and the intervenors. LG&E was directed to give notice to its consumers of the proposed rates and the scheduled hearing pursuant to 807 KAR 5:011, Section 8. A hearing to receive public comment and testimony was conducted on

March 7, 1988 at the Jefferson County Courthouse in Louisville, Kentucky.

The Commission granted motions to intervene filed by the Utility and Rate Intervention Division of the Office of the Attorney General ("AG"); Jefferson County ("County"); the City of Louisville ("City"); the Department of Defense of the United States ("DOD"); the Utility Ratecutters of Kentucky, Inc. and the Paddlewheel Alliance, referred to as Consumer Advocacy Groups ("CAG"); the Legal Aid Society, Inc. on behalf of Darlene Baker and Jacolyn Petty, residential customers of LG&E and the Fairdale Area Community Ministries, Inc., the West Louisville Community Ministries, Inc., the Sister Visitors Center, and the Inter-religious Coalition for Human Services, Inc., who assist low-income households ("Residential Intervenors"); and the groups of Alcan Aluminum Company, Ashland Oil Inc., Ford Motor Company, Frito-Lay, Inc., General Electric Company, B. F. Goodrich Chemical Group, Interez, Inc., Reynolds Metals Company, and Rohm and Haas Kentucky, Inc., the Kentucky Industrial Utility Customers ("KIUC").

The hearings for the purpose of cross-examination of the witnesses of LG&E and the intervenors were held in the Commission's offices in Frankfort, Kentucky, on March 22-25, 28-29, 1988 and April 4-8, 11-12, 14 and 18, 1988 with all parties of record represented. Briefs were filed May 9, 1988 and the information requested during the hearings has been submitted.

COMMENTARY

LG&E is a privately-owned electric and gas utility which distributes and sells electricity to approximately 311,600 consumers in Jefferson County, and in portions of Bullitt, Hardin, Meade, Oldham, Shelby, Spencer, and Trimble counties and distributes and sells natural gas to approximately 237,000 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 and the Commission has accepted the 12-month period ending August 31, 1987 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period the Commission has given full consideration to appropriate known and measurable changes.

VALUATION

LG&E presented the net original cost, capital, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates. As in the past, the Commission has given limited consideration to the proposed reproduction cost.

Net Original Cost

LG&E proposed a total company net original cost rate base of $1,345,749,137. Generally, the proposed rate base was determined in accordance with the Commission's decision in LG&E's last rate case. The net investment rate base has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses in the calculation of the allowance for working capital. As discussed further in the section of this Order relating to the extraordinary property losses, the net investment rate base has been reduced by $19,571,002 to reflect adjustments to the accumulated depreciation reserve and the deferred income tax accounts. The rate base has been increased by $72,780 to recognize 1 year's amortization of the unprotected excess deferred income taxes resulting from the reduction of the corporate tax rate in the Tax Reform Act of 1986 ("Tax Reform Act"). This is achieved by decreasing the deferred tax reserve account to reflect the amortization adjustment described in the section of this Order relating to Excess Deferred Taxes. All other elements of the net original cost rate base have been accepted as proposed by LG&E.

In LG&E's last rate case, the Commission placed LG&E on notice that the Federal Energy Regulatory Commission ("FERC") rulemaking procedure concerning the calculation of working capital would be considered in LG&E's future rate proceedings. FERC has not moved forward on this matter and at this time has not required a lead-lag study for the calculation of cash working capital. In this case, LG&E has determined the allowance for working capital in the same manner as in past rate cases with cash working capital calculated using the 45 day or 1/8 formula.

Thomas J. Prisco, on behalf of the DOD, recommended the use of the balance sheet approach to calculate working capital. His methodology was based upon correspondence from the National Association of Regulatory Utility Commissioners Annual Regulatory

Studies Program and various accounting books. The Commission agrees with the position of the DOD that consumers should not be required to pay rates which include an allowance for excess working capital. However, based on the evidence presented in this proceeding, the Commission is not convinced that the method offered by the DOD is an accurate representation of the balance sheet approach and, therefore, of LG&E's working capital needs. The Commission has, therefore, determined the allowance for working capital in the same manner as proposed by LG&E using the 45 day or 1/8 formula for cash working capital.

The net original cost rate base devoted to electric and gas operations is determined by the Commission to be as follows:

	Gas	Electric	Total
Total Utility Plant	$196,479,603	$1,702,353,408	$1,898,833,011
ADD:			
Materials & Supplies	1,443,870	46,126,080	47,569,950
Gas Stored Underground	22,166,664	-0-	22,166,664
Prepayments	341,417	1,431,429	1,772,846
Cash Working Capital	4,092,780	31,914,475	36,007,255
Subtotal	$ 28,044,731	$ 79,471,984	$ 107,516,715
DEDUCT:			
Reserve for Depreciation	72,817,435	416,540,389	489,357,824
Customer Advances	2,876,070	1,228,267	4,104,337
Accumulated Deferred Taxes	16,988,797	167,531,323	184,520,120
Investment Tax Credit (3%)	508,000	1,421,030	1,929,030
Subtotal	$ 93,190,302	$ 586,721,009	$ 679,911,311
NET ORIGINAL COST RATE BASE	$131,334,032	$1,195,104,383	$1,326,438,415

Capital

LG&E's Controller, M. Lee Fowler, proposed adjustments to LG&E's $1,362,822,255 end-of-test-year capital of $12,250,000. Long-term debt was adjusted to reflect "(1) the retirement of $12,000,000 of 4 7/8 percent First Mortgage Bonds; Series due September 1, 1987; (2) the scheduled redemption of $250,000 of 1975 Pollution Control Bonds due September 1, 1987; and (3) the refinancing of $49,000,000 of the 9.40 percent Pollution Control Bonds."[1] The refinancing of these Pollution Control Bonds did not affect the level of capital but rather the cost of this item. A further adjustment was made to capital to reflect discounts on preferred and common stock.[2]

Dr. Carl G. K. Weaver, an economist and principal with M. S. Gerber & Associates, Inc. and witness for the AG, proposed a capital balance of $1,246,106,059.[3] The difference between Dr. Weaver's proposed capital and Mr. Fowler's was in (1) Dr. Weaver's use of an October 31, 1987 capital balance as reported in LG&E's Financial and Operating Report; and (2) in the adjustments to reflect discounts on preferred stock and common equity.[4]

Lane Kollen, a utility rate and planning consultant with the firm Kennedy and Associates and witness for KIUC, proposed a

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1 Fowler Prepared Testimony, page 14.

2 Ibid., page 17.

3 Weaver Prepared Testimony, Exhibit CGW, Statement 24.

4 Ibid., pages 35-36.

capital balance of $1,289,422,255.[5] Mr. Kollen used LG&E's proposed adjusted capital balance, but made an additional adjustment to common equity to remove "$61.15 million in excess capitalization which is not utilized to support investment in utility property."[6]

Mr. Kollen provided three arguments for reducing common equity by the $61.15 million. First, because preferred stock has remained unchanged and the long-term debt increase of $51 million in pollution control bonds was invested in utility plant, it is the growth in common equity that has been used to finance short-term investments in non-utility plant since test year end of August 31, 1983.[7] Second, "LG&E has only debt and preferred stock directly attributable to utility operations and none whatsoever for non-utility operations."[8] Third, interest and other income from short-term investments is not flowed through to the ratepayers but is received below the line as a direct benefit to the shareholders.[9]

The process proposed by Mr. Kollen of isolating one asset which is not a part of rate base and reducing capital, without a complete evaluation of other assets and liabilities with regard to rate base and capital valuation is inappropriate. In order to

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5 Kollen Prepared Testimony, Exhibit LK-2.

6 Ibid., page 6.

7 Ibid., pages 8-9.

8 Ibid., page 9.

9 Ibid., page 10.

accept Mr. Kollen's adjustment, a complete reconciliation of the assets and liabilities would be necessary to determine appropriate additions and deletions of assets and liabilities to rate base and capital. None of the parties to this proceeding have attempted to make a complete reconciliation of rate base and capital. In the absence of such thorough analysis, the Commission cannot isolate and adjust selective items as proposed by Mr. Kollen. Moreover, the dollar relationship of rate base and capital as provided in this Order is approximately $4.5 million which is reasonable. The isolated adjustment proposed by Mr. Kollen would result in rate base exceeding capital by approximately $56 million. Therefore, Mr. Kollen's adjustment to capital has not been included for rate-making purposes herein.

The adjustments to the end-of-test-year capital proposed by LG&E reflect actual changes in LG&E's end-of-test-year capital which occurred on September 1, 1987 only 1 day after the end of the test period and should be accepted. In addition, the Commission has adjusted LG&E's capital by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. Concurrent with its adjustment to the rate base to remove the extraordinary losses, a similar adjustment must be made to capital. A company's net investment in utility operations and capital supporting utility operations should be equal, and rate-making steps should be undertaken to attempt to reach this equality. Since the losses do not relate specifically to any specific component of capital, the most equitable approach is to adjust capital on a pro rata basis. Therefore, the Commission is of the opinion that an adjusted capital balance of $1,331,001,253 is reasonable.

In determining capital the test-year-end Job Development Investment Tax Credit ("JDIC") has been allocated to each component of capital on the basis of the ratio of each component to total capital excluding JDIC, as proposed by LG&E. The Commission is of the opinion that this treatment is entirely consistent with the requirement of the Internal Revenue Service that JDIC receive the same overall return allowed on common equity, debt, and preferred stock.

Reproduction Cost

LG&E presented the reproduction cost rate base in Fowler Exhibit 9. Therein, LG&E estimated the value of plant in service, plant held for future use, and construction work in progress ("CWIP") at the end of the test year. The resulting reproduction cost rate base is $2,542,427,739 which includes electric facilities of $2,174,716,164 and gas facilities $367,810,575.

TRIMBLE COUNTY GENERATING STATION ("TRIMBLE COUNTY") - CWIP

In LG&E's last rate case, as well as the Order issued on October 14, 1985 in Case No. 9243, An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1, the Commission put LG&E on notice that the historical treatment of CWIP allowed in previous cases should not be taken as an indication that the treatment would continue indefinitely in future cases. In addition, due to the uncertainties surrounding the Trimble County project, the Commission initiated monitoring procedures to keep abreast of the

Trimble County activity. This monitoring contributed to the establishment of Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1.

In the Order in Case No. 9934 entered on July 1, 1988, the Commission found that 25 percent of Trimble County should be disallowed. In this proceeding, the Commission has heard evidence with regard to the rate-making treatment of Trimble County CWIP; however, there has been no specific testimony offered regarding the various options for rate-making treatment of a disallowance of 25 percent of the cost of Trimble County. Furthermore, in Case No. 9934, since the Commission's decision is being issued concurrently with this Order, there has been no specific investigation of the revenue requirement effects of a 25 percent disallowance of Trimble County. Therefore, the Commission has determined that another proceeding will be established to allow a full investigation of this issue. An Order establishing this case will be rendered in the immediate future.

In order to protect the interests of the consumers and assure that the disallowance will be recognized from the date of this Order, the Commission is of the opinion that all revenues associated with additions to CWIP since LG&E's last rate case should be collected subject to refund. The Trimble County CWIP included in rate base in LG&E's last rate case was $268 million and Trimble County CWIP has achieved a level of $382 million at the end of the test period in this case. Applying the overall rate of return allowed in this case to the increase in Trimble County CWIP of $114 million results in an annual provision of $11.4 million to be collected subject to refund. The final amount of disallowances will be determined in the forthcoming Trimble County CWIP case soon to be established and the current ratepayers will realize the benefits of the disallowance when an Order is issued in that case.

In this proceeding, as in LG&E's last two rate cases, the Commission has addressed the issue of continuing the practice of allowing CWIP in LG&E's rate base. While both LG&E and the intervenors have presented arguments supporting and opposing the practice of allowing a return on CWIP, neither side has presented any new arguments or evidence which has not already been considered by this Commission. Consequently, based on the evidence in this case, the Commission is of the opinion that the present regulatory treatment of allowing a cash return on CWIP should continue in light of the decision to complete Trimble County. However, the final amounts utilized for rate-making and revenue requirement determination will be decided in the future proceeding announced in this section of the Order.

RETIREMENTS OF SULFUR DIOXIDE REMOVAL SYSTEMS ("SDRS") AND GAS PLANT

As part of this case, the Commission Staff reviewed LG&E's accounting treatment for the retirement of SDRS and three underground storage fields ("gas fields"). The Staff gave LG&E notice through cross-examination and data requests that the accounting treatment utilized by LG&E ignored the impact these retirements had on LG&E's rate base and the return on that rate base.[10] LG&E

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[10] Response to the Commission Orders dated December 23, 1987, Item No. 42(a-e); dated January 15, 1988, Item No. 69; and Hearing Transcript, Vol. IV, pages 7, 13-19.

initially advised the Staff in 1986 that it planned to account for the abandoned gas fields as a normal retirement under the Uniform System of Accounts ("USoA"). The accounting treatment was investigated in this case because this was LG&E's first general rate case since these retirements had taken place.

LG&E stated that this accounting treatment was its usual procedure in accounting for abandonments and retirements.[11] In addition, LG&E determined that these entries resulted in a depletion of the depreciation reserve which was now deficient. LG&E proposed to revise upward the depreciation rates for underground gas plant to eliminate the deficiency. The revision was made in 1986, with the depreciation rate for underground gas plant increasing from 3.37 percent to 5.05 percent.[12]

The abandoned gas fields were comprised of several million dollars of undepreciated plant per the company's books. While most of the gas fields were being depreciated over approximately 30 years, significant portions of the gas fields had been in service less than 15 years. As a result of the abandonment, LG&E reported an income tax loss of $3,973,815[13] in 1985. Preliminary figures supplied by LG&E indicated that a book loss, at least as great as the tax loss, existed.[14]

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11 Response to the Commission Order dated December 23, 1987, Item No. 42(a), page 1 of 2.

12 Ibid., dated January 15, 1988, Item No. 69(f)(3), page 3 of 3.

13 1985 FERC Form No. 1, Annual Report of LG&E, page 261.

14 Response to the Commission Order dated January 15, 1988, Item No. 69(f)(1), page 2 of 37.

During 1986, Commission Staff obtained information from LG&E which reflected that early retirements of SDRS units were significant and had been accounted for in the same manner as the abandoned gas fields.[15] It was apparent that a depletion of the electric steam production plant depreciation reserve resulted. Since the accounting treatment for these early retirements results in a material impact on revenue requirements, the Commission is of the opinion that this subject is appropriately an issue in this case.

The subject of these early retirements and abandonments has been thoroughly explored through information requests and in cross-examination of LG&E witness, Mr. Fowler. From the information requests, it was determined that for the period 1984 through 1986, LG&E had incurred losses of $21,052,354 due to the early retirements of SDRS units and losses of $6,862,820 due to the abandonment of the gas fields in 1985.[16] If the electric and gas losses are combined, the total losses on these early retirements are $27,915,174. LG&E claimed tax losses on the SDRS units retired between 1984 and 1986 of $3,029,756.[17]

LG&E objected to the questioning of Mr. Fowler on the grounds that the accounting treatments utilized for the SDRS units and gas fields were not relevant to its rate application. LG&E observed that the events did not occur in the test year, and it believed

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[15] Ibid., Item No. 69(f)(2 and 3), page 1 of 3.

[16] Ibid., Item No. 69(f)(1), page 2 of 37.

[17] Ibid., Item No. 69(a), page 1 of 4.

that it was not a proper issue for consideration in this case.[18] The Commission finds that even though the actual retirements and abandonments did not occur in the test year, the subject is highly relevant to this rate case. The impact of retirements losses totaling $27,915,174 exists in the accumulated depreciation reserve and thus is reflected in the net original cost rate base. LG&E has already revised its depreciation rates for underground gas storage plant to offset a portion of the loss and seeks to reflect that change in this case. Moreover, the accounting treatment employed by LG&E does not properly disclose the impact of the early retirements and allows LG&E a full return on the net amount of the losses while the losses are being recovered through depreciation accruals.

LG&E's approach to the retirements transactions, on the surface, is simple and straightforward. While book losses generated by early retirements and abandonments can produce deficiencies in the accumulated depreciation reserve, the increasing of depreciation rates on existing plant will make up the deficiency. Mr. Fowler pointed out that, under LG&E's use of whole life, functional group depreciation, utility plant will often be depreciated beyond the estimated service life and thus can help reduce any existing deficiency.[19]

However, LG&E has failed to recognize that its approach allows the company to reap a double benefit at the ratepayers'

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[18] Hearing Transcript, Vol. III, pages 177-178.

[19] Ibid., Vol. IV, page 12.

expense. While plant is in service, a company will usually receive a return on the plant and recover the cost of the plant. This is accomplished through the return on the rate base and depreciation expense. LG&E seeks to retain this arrangement on plant that has been retired or abandoned. This approach not only allows for recovery of the inherent deficiency in accumulated depreciation through depreciation expense, but also allows a return on the loss by overstating the rate base. LG&E has maintained that its current treatment benefits its ratepayers by the reserve deficiencies being made up over several years, rather than recovered over a 3- to 5-year period. LG&E contends that 3 to 5 years is a normal amortization period for extraordinary losses, but Mr. Fowler could not cite a publication or pronouncement that supported this claim.[20]

The Commission recognizes that one of the problems which causes this situation is that general plant accounting instructions contained in the USoA does not specifically provide for the possibility of a loss occurring at the time of any retirement. There are three types of property losses provided for in the USoA: losses arising from the disposition of future-use utility plant; losses on the sale, conveyance, exchange or transfer of utility or other property to another; and extraordinary property losses. This last type of loss requires the creation of a deferred debit in Account No. 182, Extraordinary Property Losses.[21] The

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20 Ibid., Vol. III, pages 188-189; Vol. IV, pages 22-23, 51-52.

21 USoA, Electric and Gas Plant Instructions, Item No. 10, parts E and F.

amortization of the account over a set period of years is anticipated in USoA instructions.

In the absence of specific accounting treatment in the USoA, the Commission may utilize other authoritative accounting sources. The Commission generally attempts to minimize discrepancies between generally accepted accounting principles ("GAAP") and its prescribed accounting treatment. Under GAAP applied to non-utility business enterprises, the possibility of a loss occurring at the time of retirement of an asset is specifically recognized. Under those standards, when a major asset is retired from use, the cost and related accumulated depreciation are removed from the accounts, which is similar to the approach outlined in the USoA. However, under GAAP, the charge to accumulated depreciation is limited to the depreciation provided on the asset and since the depreciation expense charged over the estimated useful life of the asset is only an allocation of the cost based on an estimate, a gain or loss will normally be realized on disposal of the asset.

It is conceivable that in GAAP accounting for non-utility enterprises, the practice of group depreciation would exist in which case the entity would account for an asset retired from service in the same manner as prescribed in utility accounting. Thus, it is apparent that another discrepancy in dealing with this issue lies in the eligibility of an asset for group life depreciation. The Commission is of the opinion that the assets here, the gas fields and the SDRS units, are of sufficient value and identifiable enough to warrant individual asset accounting treatment for depreciation and retirement accounting. Thus, the arguments with regard to group depreciation are not valid.

Of the three types of treatment of losses available to LG&E under the USoA, the only applicable treatment is the extraordinary property loss. To be considered extraordinary, the transaction must be of significant effect, not typical or a customary business activity, and would not be expected to recur frequently or be considered as a recurring factor in the evaluation of the ordinary operating process of the business.[22] These restrictions are similar to those prescribed under GAAP. In Accounting Practices Board ("APB") Opinion 30, an extraordinary item is defined as a transaction which is of an unusual nature and has an infrequency of occurrence given the environment in which the business operates.[23] Under the current USoA, the use of extraordinary treatment must be approved by the Commission, upon the request of the company.

Based on the information contained in the record, the Commission finds that the early retirements and abandonments constituted extraordinary property losses, and that LG&E should have requested such treatment. The size of the book losses for the SDRS units and gas fields would be considered significant. LG&E has been an industry leader in SDRS technology, a technology which was new and for which service life history was nonexistent. Mr. Fowler stated at the hearing that the company's experience with SDRS units was

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[22] Ibid., Item No. 7.

[23] APB Opinion 30, paragraph 20.

unusual.[24] The gas fields were abandoned based on the recommendations of a consultant hired by LG&E.[25] While the USoA requires the company to seek Commission approval for the use of extraordinary treatment, the lack of such action on the part of LG&E causes the initiative to shift to the Commission.

It appears that LG&E has failed to recognize the impact its approach has on accounting and rate-making treatments. The use of revised depreciation rates on existing total utility plant is an example of the accounting impact. It is understandable that depreciation rates need to be revised from time to time due to changes in the actual service life history and technological advances. However, increasing the depreciation rates on existing plant to recover deficiencies created by early retirement or abandonment of major items of plant is not justifiable in this instance. If depreciation rates should be increased to make up deficiencies resulting from extraordinary property losses, once the deficiencies are made up the rates should be revised downward. With regard to the rate-making impact, the accumulated depreciation reserve is understated until the reserve is restored by the increased depreciation resulting from the depreciation rate revision. The understated accumulated depreciation reserve in turn causes the net original cost rate base to be overstated. Thus, if the revenue requirement is based on the return granted on

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24 Hearing Transcript, Vol. III, pages 179-180, 190-191.

25 Response to KIUC's Second Data Request filed February 1, 1988, Item No. 16.

rate base, the revenue required is inflated due to the overstated rate base.

In addition to the impact of the deficiencies in the accumulated depreciation reserve, there is also the issue of the rate-making treatment of deferred income taxes generated by the retired assets. LG&E was asked to provide the deferred income tax balances related to the SDRS units and the gas fields. For the gas fields, LG&E was able to respond that at the date of abandonment deferred income taxes totaled $3,059,100, and that $162,000 had been flowed back by the test year-end, for a balance of $2,897,100.[26] For the SDRS units, LG&E continually stated that this deferred income tax figure could not be readily determined due to the manner in which its deferred tax accounts were maintained. LG&E has identified the total SDRS deferred income tax balance as $4,910,100 at the date of retirement,[27] $5,146,000 at test year-end,[28] and $5,268,800 at calendar year-end 1987.[29] In addition, LG&E stated these figures included the impact of any flowbacks of these taxes. In calculating the balances, LG&E frequently speaks of "presumed retirement dates," and that in some cases, tax depreciation continues after retirement.[30] These

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26 Supplemental Hearing Data Request, filed May 17, 1988, page 4.

27 Response to the Commission Order dated January 15, 1988, Item No. 69(d)(1).

28 Supplemental Hearing Data Request, filed May 17, 1988, page 2.

29 Ibid., filed May 10, 1988, page 1.

30 Ibid., filed May 10 and 17, 1988, page 1.

retirements have occurred, there is no presumption involved. Also, LG&E has not cited references to the Internal Revenue Code to support its claim that tax depreciation can be taken after the retirement of the depreciated asset. Based on the information supplied by LG&E, the Commission believes the most accurate deferred income tax balance for the SDRS units is $4,910,100, the reported balance at the time of the retirement.

In its brief, LG&E proposed that if the Commission required it to recognize the losses as extraordinary and establish regulatory assets, that the regulatory assets should be amortized over a period of 5 years.[31] However, Mr. Fowler stated that, utilizing a 5-year amortization period, the revenue requirements generated under the extraordinary loss proposal would be higher than those generated using LG&E's original accounting and rate-making treatment of the retirements.[32]

The Commission believes that the approach proposed by LG&E in this situation is not proper. The Commission believes that in the situation of the early retirement of the SDRS units and the abandonment of the gas fields, LG&E should have sought extraordinary property loss treatment for these transactions. LG&E's assumption that early retirements are offset by late retirements may be true for certain assets which qualify for group depreciation, but not in the current situation which demonstrates the basic problems of the assumption with regard to the plant retirements in question.

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[31] LG&E Brief, filed May 9, 1988, page 44.

[32] Hearing Transcript, Vol. IV, pages 14-15.

The dollar magnitude of these retirement losses should not be made up by LG&E by "over depreciating" current assets, since this would result in excessive recovery under ordinary rate-making practices and is not an appropriate criterion on which to base a change in depreciation rates.

Therefore, the Commission hereby requires the extraordinary property loss treatment for the losses experienced with the early retirement of the SDRS units and the abandonment of the gas fields. As such, the accumulated depreciation reserves for both the electric and gas plants should be credited $21,052,354 and $6,862,820, respectively. The debit should be to Account No. 182, Extraordinary Property Losses, with electric and gas subaccounts maintained. The deferred income tax accounts should be debited $4,910,100 for electric and $2,897,100 for gas. The corresponding credits will be to the appropriate subaccount of Account No. 182. The ratepayers of LG&E have provided the dollars represented in the deferred income tax balances. The netting of the total loss to be amortized recognizes this fact.

In determining a proper amortization period, the Commission has considered the undepreciated balance of the assets retired, the impact on operating expenses, and the ultimate effect on the ratepayers and stockholders. The Commission is of the opinion that an amortization period of 19 years is reasonable for the electric extraordinary property loss and that 18 years is reasonable for the gas extraordinary property loss. This represents an approximation of the number of years of the remaining service lives on the assets retired which LG&E had utilized for book depreciation purposes. Had LG&E's approach proposed in its Brief been utilized, with no change in the depreciation rates, it would have recovered the losses approximately over the same period of time. An annual amortization expense of $849,592 for the electric and $220,318 for the gas has been included for revenue requirement determination herein.

The company's proposal to increase the gas depreciation by $211,035 is unnecessary and the gas depreciation expense has been adjusted to reflect the depreciation expense based on the 3.37 percent depreciation rate in effect before the gas field abandonment. The income tax impacts of these adjustments have been included in the calculation of book income tax expense. The net-original cost rate base has been adjusted by $19,571,002 to reflect the accounting entries to the accumulated depreciation reserve and the deferred income tax accounts. The electric rate base has been reduced by a net amount of $16,142,254 reflecting the $21,052,354 increase to electric accumulated depreciation and reduced by the $4,910,100 reduction to electric deferred income taxes. The gas rate base has been reduced by a net amount of $3,428,748 reflecting the $6,862,820 increase to gas accumulated depreciation and reduced by the $2,897,100 reduction to gas deferred income taxes and the $536,972 reduction to gas depreciation expense due to the depreciation rate adjustment.

MANAGEMENT AUDIT OF LG&E

In August 1986, the Commission's Management Audit of LG&E ("Management Audit") was completed. The audit was performed by Richard Metzler and Associates, Inc. and Scott Consulting Group

("RM&A/Scott") under a statute enacted by the Kentucky General Assembly. According to the Executive Summary, the potential cost avoidance or reduction identified during the audit is probably in excess of $6 million to $7 million in annual recurring and $9 million to $10 million in one-time cost savings.[33] RM&A/Scott developed implementation action plans ("Action Plans") for each of the 146 recommendations and LG&E was directed to provide semi-annual reports to the Commission on the implementation of the recommendations.

This is LG&E's first request for a general increase in rates since the completion of the Management Audit. In prepared testimony, Robert L. Royer, President and Chief Executive Officer of LG&E, and Fred Wright, Senior Vice-President of Operations, noted that LG&E had incurred substantial expenditures to implement the Management Audit recommendations. The Commission demonstrated concern regarding the costs and benefits resulting from the Management Audit through the numerous information requests submitted to LG&E. LG&E was requested to provide a witness at the hearing for cross-examination regarding the Management Audit.

This section will focus on four general areas of the audit identified by the following subsections.

1. Closed Recommendations.
2. Management Information Systems.
3. Work Force - Compensation Recommendations.
4. Open Recommendations.

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[33] Management Audit of LG&E, Executive Summary, II-13.

Closed Recommendations

In response to the Commission Order dated January 15, 1988, F. L. Wilkerson, Vice-President of Corporate Planning and Accounting for LG&E, provided information regarding the cost and savings of 45 audit recommendations which have been implemented and closed.[34] The response indicated that the test year included $510,300 to $535,300 in costs associated with these recommendations and that the estimated recurring costs were in the order of $719,500 to $749,500. The estimated savings associated with these recommendations actually quantified in that response was related to only 2 of the 45 closed recommendations and totaled $167,000. During cross-examination, Mr. Wilkerson indicated that it is difficult to quantify the savings for this group of recommendations and that the savings, for the most part, were not measurable.[35] As a result, LG&E was requested to file additional information which would provide a description of the nature of the costs included in the test year, identify the type of savings or benefit and the functional area in which the savings will occur, and indicate whether the benefits will be one-time or recurring in nature.

The Commission has reviewed the information filed relevant to these closed recommendations and finds that the actions taken by LG&E in association with the implementation of these recommendations are in the interests of LG&E's consumers. The Commission is

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[34] Response to the Commission Order dated January 15, 1988, Item No. 5.

[35] Hearing Transcript, Vol. VIII, pages 194-195.

however, concerned with LG&E's failure to quantify the savings and/or benefits associated with implementation of audit recommendations and particularly with the level of estimated recurring costs. In future rate proceedings, LG&E should be better prepared to support the recurring costs associated with closed recommendations in order for the Commission to be able to better determine their reasonableness in light of the associated savings and/or benefits.

Management Information Systems

In response to Item Nos. 1(a) and (b) of the Commission Order dated December 23, 1987, LG&E provided a discussion of its efforts to develop or enhance its major management information systems. The actual development of most of these systems was begun prior to the Management Audit.[36] However, the Management Audit includes numerous recommendations relating to these systems.

The test year includes operating expenses of approximately $2,476,000 associated with development of these systems. LG&E has estimated that they will incur additional costs of $2,421,000 over the 12-month period ending August 31, 1988.[37] Additionally, LG&E has indicated that the estimated expenditures at the completion of the development of these systems will be $11,711,000 operating and maintenance costs and $2,327,000 capital costs.[38]

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36 Ibid., page 208.

37 Response to the Commission Order dated December 23, 1987, Item No. 1(a).

38 Response to Hearing Information Request, Item No. 3, Response 7.

The *Executive Summary of the Management* Audit addresses, in general terms, the status of LG&E's business systems and indicates that 3 to 5 years will be required to bring LG&E's computer-based systems up to par with the industry.[39] In response to a request for information made during the hearing, LG&E filed documentation indicating that the systems would be completed beginning in 1988 and continuing through 1991.[40] That response also indicated that the development of some of these systems began as early as 1983. Additional information in the record indicates these systems are still under development and that benefits that may result have not yet been realized. Further, LG&E has indicated that any savings or benefits are not likely to exceed the costs during the immediate future.[41]

LG&E was questioned regarding any cost-benefit analysis performed in connection with these systems and the appropriateness of expensing rather than capitalizing the cost of developing these systems. Cost-benefit analyses of the management information systems, though requested, have not been filed in this proceeding and it is not clear if LG&E has prepared updated cost-benefit analyses as projects progress.[42] Mr. Wilkerson indicated that LG&E felt that it was appropriate to expense the development costs

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39 Management Audit of LG&E, Executive Summary, II-7 to II-8.

40 Response to Hearing Information Request, Item No. 3, Response 7.

41 Response to the Commission Order dated December 23, 1987, Item No. 1(b).

42 Hearing Transcript, Vol. VIII, page 218.

of these systems because LG&E is paying for those costs in today's dollars, because the systems cost money up front, and because unless the company is willing to spend the money no savings will result. Mr. Wilkerson cited a paragraph relating to cost reduction penalties from the Executive Summary as support for LG&E's position.[43] This paragraph however does not address the accounting or rate-making treatment associated with the costs, and includes no prohibition in regard to capitalization of development costs.

The Commission is of the opinion that for the purpose of determining revenue requirements in this proceeding, the test-year operating expenses should be decreased by the $2,475,092 associated with the development costs of the management information systems. The management information systems are being developed to provide benefits to LG&E and its customers over an extended period time. LG&E should begin subsequent to the date of this Order to capitalize and amortize, over a reasonable time period, development costs associated with the management information systems. The costs incurred during and prior to the test year have been expensed during those accounting periods. Therefore, no adjustment to rate base is necessary. The rate-making treatment of costs, capitalized subsequent to the date of this Order, will be considered in future rate proceedings.

Work Force - Compensation Recommendations

The Management Audit contained numerous recommendations relating to the organization structure, work force, and compensation and benefits programs of LG&E. The Executive Summary noted that LG&E could produce annual payroll savings of at least $2.5 million by implementing work force recommendations exclusive of Trimble County considerations.[44] The Management Audit indicated that these savings can be accomplished by:

> . . . increasing organizational productivity through the establishment of work management systems, reducing layers of management, increasing spans of managerial control and revising the personnel skill mix . . .[45]

In addition, specific recommendations instructed LG&E to review the compensation and benefit programs and to annually review health insurance and other benefits programs.

These recommendations are of particular concern to the Commission for several reasons. First, the proposed $5,390,668 increase to test-year operating expenses for labor and labor-related costs was the largest single adjustment proposed by LG&E excluding the adjustments for electric weather normalization and fuel expenses. Second, LG&E was notified in its last rate proceeding, wherein it proposed an increase of $558,000 for Blue Cross-Blue Shield insurance, of the Commission's intended review in the next rate proceeding. In this case, $1,224,561 or approximately 23 percent of the proposed labor and labor-related increase is for health insurance. Third, the level of LG&E's employees has

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43 Ibid., pages 239-240.

44 Management Audit of LG&E, Executive Summary, II-13.

45 Ibid.

been steadily increasing, from 3,646 in 1985[46] to 3,920 on September 6, 1987 and to 3,988 on November 15, 1987.[47]

Moreover, when all of these work-force related recommendations are considered as a whole, they indicate the need for a thorough, comprehensive evaluation of LG&E's organizational structure, and compensation and benefit packages. According to LG&E, the review of the organizational structure, including work force considerations, has begun and LG&E should be able to meet the 3- to 5-year time frame for completion cited in the audit. The Commission is concerned with LG&E's progress in implementing the work-force reduction recommendation of the Management Audit. In August 1986, the Management Audit Report recommended that a reduction in LG&E's work force of 50 to 200 personnel over a 3- to 5-year period exclusive of the Trimble County construction should be accomplished. In response to the recommendation on October 31, 1987 LG&E promulgated its Human Resources Control Program essentially freezing the level of employment on that date and stating a company goal of reducing employment overall. Though LG&E is apparently implementing the planning mechanism called for in the Management Audit, the Commission is concerned with the continued expansion of its work force and the speed at which LG&E is implementing its employment control program. During the period from December 1986 to November 1987, LG&E expanded its work force

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46 Management Audit of LG&E, Chapter XI, Human Resources Management, Exhibit XI-10, Staffing Trends by Employee Group (1975-1985).

47 Response to the Commission Order dated January 15, 1988, Item No. 14.

exclusive of Trimble County from 3,162 to 3,210. The trend in employment is contrary to the intent of the auditors' recommendation and at the very least requires a more detailed explanation than has been provided by LG&E as to the reasons for the work force expansion. The Commission will continue to monitor the non-Trimble County level of employment in the future and will require LG&E to provide a complete explanation for any change in the work force on a semiannual basis. This initial report should be provided to the Management Audit Section starting October 31, 1988.

During the test year, LG&E developed a benefit improvement package for nonunion employees, granted the officer group salary increases greater than would normally have been considered and improved the supplemental benefits authorized for officers.

The improvements for the officer group were intended to address salary compression, and compensation and benefit levels lower than industry averages. LG&E has indicated that the incremental cost of the improvements for this group is between $40,900 and $50,200 for the test year. The benefit improvement package instituted by LG&E included changes in health insurance and group life insurance, and added a thrift-savings plan. This package is of particular concern to the Commission because of the impact on test year costs and the overall level of fringe benefits.

LG&E was notified in Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated May 16, 1984, of the Commission's intention to review health insurance costs in the next rate proceeding. In addition, the Management Audit contains recommendations directing LG&E to evaluate the compensation and benefit programs and to review health insurance and other benefits programs to ensure cost effectiveness. Mr. Wilkerson, during cross-examination, indicated that the benefit improvement package was not instituted in response to the Management Audit, but for other reasons, among them, maintaining the nonunion benefits comparable to the union employees.[48]

William H. Hancock, Jr., Senior Vice-President of Administration and Secretary of LG&E, presented testimony regarding health insurance and other fringe benefits. He discussed the health insurance cost containment measures taken by LG&E and the newly instituted flexible medical benefit plan. Hancock Exhibit 1 indicates that the rate of increase after cost containment for Blue Cross-Blue Shield insurance was 1.4 percent compared to a rate of 12.8 percent prior to cost containment.[49] Hancock Exhibit 2 reflects an increase in average cost per participant of 29 percent from August 1983 to August 1987 as compared to an industry trend factor of 63 percent over 4 years.[50] These exhibits provide the basis of support regarding LG&E's attempts to control health insurance costs. However, for the 2 years immediately following the institution of the cost containment measures the rate of

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48 Hearing Transcript, Vol. VIII, pages 223-224.

49 Hancock Prepared Testimony, Exhibit 1.

50 Ibid., Exhibit 2.

increase is above 10 percent per year.[51] In addition, the basis of the 63 percent industry trend factor was a letter from an actuarial consultant[52] which neither defines the precise calculation of the factors nor the region considered. The only evidence by which the success of LG&E's cost control efforts can be compared to other utilities or companies in the area that LG&E serves or the state is this ambiguous letter from the actuarial consultant.

Mr. Hancock's testimony indicates that the annual reduction in medical benefits resulting from the flexible benefits program is approximately $500,000.[53] However, the savings are offset by a 3-year cash incentive payment to employees switching to the plan. The test-year operating expenses include $196,408 associated with the payment of the cash incentive for the first year. However, this is only the amount not paid in cash but contributed to the new thrift savings plan. The employees electing to receive actual cash payments received those payments in December 1987 after the end of the test period.

In the Management Audit Action Plan Progress Reports ("Progress Reports") submitted to the Commission in November 1986, LG&E indicated that the company was working with a consultant to evaluate alternate benefit packages and would submit a proposal to

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51 Response to the Commission Order dated December 23, 1987, Item No. 5(d).

52 Response to KIUC First Information Request dated January 14, 1988, Item No. 8, page 2.

53 Hancock Prepared Testimony, page 4.

senior management for consideration.[54] The record in this case contains no evidence that LG&E made any evaluations with regard to any fringe benefits other than health insurance. However, on April 1, 1987, LG&E instituted the new benefit improvement package which will increase LG&E's expenses.

The Commission stated its concern in LG&E's last rate case regarding the level of Blue Cross-Blue Shield insurance. Furthermore, the management auditors recommended that LG&E review, not only health insurance, but the total benefits package. The Commission's and the auditors' concern in this area would require that LG&E provide more adequate support than that which has been included in this proceeding to justify the cost increases to be borne by the ratepayers. Therefore, the Commission is of the opinion that the cost of the change in group life insurance, the cost of the thrift savings plan, and the cost of the cash incentive payments should not be borne by LG&E's ratepayers. The effect of these changes on LG&E's test year costs is specified in the later section of this Order dealing with the proposed labor and labor-related adjustments.

Open Management Audit Recommendations

During cross-examination, Mr. Wilkerson was asked to provide budget projections which reflect the future costs for the projects that were being implemented pursuant to the Management Audit. Mr. Wilkerson responded that the 90 or so open recommendations had not been identified in the budget process and were not readily

[54] Management Audit Action Plans, November 1986, XI-8, page 2.

identifiable.[55] LG&E is hereby placed on notice that in future rate proceedings, the company should be prepared to identify and provide the costs associated with Management Audit recommendations. Due to LG&E's current inability to track these costs and its failure to adequately support, with proper documentation, the claim that post-test year costs will be incurred at the same level as the test year, the Commission finds that the costs associated with the open recommendations should not be included in the determination of revenue requirements.

The test year costs associated with these recommendations were provided in response to Item No. 1 of the Commission's Order dated January 15, 1988. The calculation of the amount disallowed, which is approximately $258,000, is included in a later section of this Order.

Summary

The Commission compliments LG&E on the progress it has made in the implementation of its Action Plans. The Commission continues to have confidence in the benefits that both LG&E and its consumers can derive from proper implementation of its Action Plans. However, the Management Audit, Action Plans, and Progress Reports do not absolve management from its responsibility to continuously monitor and document both the costs and benefits from implementing the recommendations of the management auditors. In future rate proceedings, LG&E should be better prepared to

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55 Hearing Transcript, Vol. IX, pages 76-77.

identify implementation costs, ongoing costs, as well as benefits resulting from implementation of its Action Plan.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $118,858,318. 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 $111,795,250.[56] Subsequent to its original filing, LG&E proposed several correcting adjustments, which are addressed herein. The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Temperature Normalization - Electric

LG&E proposed an adjustment to electric revenues and expenses for deviations from normal temperatures. The proposed adjustment would reduce operating income by $7,673,763 based on the assumption that the test year included an excess of 402 cooling degree days ("CDD") and a deficiency of 362 heating degree days ("HDD").

An electric temperature normalization adjustment has been proposed in each of LG&E's past three rate applications. In Case No. 8284, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated January 4, 1982, and Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated March 2, 1983, the adjustment was proposed by LG&E; however, in Case No.

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[56] Fowler Prepared Testimony, Exhibit 4.

8924, the adjustment was proposed by an intervenor. The Commission denied the proposed adjustments in each case. In his oral testimony, Patrick Ryan, a Load and Economic Research Analyst with LG&E, summarized the concerns expressed by the Commission in those past cases and stated that the methodology presented in this case addressed those concerns and was the most appropriate way to make this type of adjustment.[57]

This adjustment accounts for 15.4 percent[58] of LG&E's overall requested revenue increase. Additionally, Mr. Ryan has stated that if LG&E's rates are based on excess KWH sales, LG&E's only opportunity to recover its revenue requirement is if the test-year weather pattern occurs in each succeeding year.[59] However, this statement covers only one part of the Commission's concern with the proposed adjustment and the converse of this statement must also be considered. That is, if revenues are based on below normal sales, then consumers will be paying rates that may generate revenue in excess of authorized revenue requirements. Thus, prior to acceptance, it is imperative that the Commission determine if LG&E has accurately reflected the relationship of KWH sales and temperature.

LG&E's methodology begins with the definition of normal weather and the determination of the difference between normal (or expected) weather and actual test year weather. For purposes of

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57 Hearing Transcript, Vol. V, pages 9-11.

58 Ryan Prepared Testimony, page 4.

59 Ibid.

calculating the weather adjustment, actual and normal degree day data, the measures of weather used in this analysis were converted from a calendar month basis to that of billing cycles. Because LG&E bills its customers in cycles, it was necessary to calculate both billing cycle days and billing-cycle degree days to match weather data with sales data.

In determining normal billing-cycle degree days, LG&E used the National Oceanic and Atmospheric Administration's ("NOAA") 1951-1980, 30-year average degree day data. By using this average, LG&E has failed to include the degree day data from the most recent 7 years. The Commission is aware from a review of NOAA literature that the NOAA will prepare special HDD or CDD tabulations or other summaries which would include more recent data.[60] However, at the hearing, LG&E indicated that no attempt has been made recently to contact the NOAA to try to get more current degree day normals.[61] The Commission's language in its Order in Case No. 8616 clearly states that current data should be used to define normal degree days:

> A current [emphasis added] 30-year period provides accurate up-to-date information and at the same time is long enough to mitigate any abnormalities in weather conditions, whether they be yearly or cyclical.[62]

60 Environmental Information Summaries, C-14, HDD and CDD Day Data, NOAA, Department of Commerce, USA.

61 Hearing Transcript, Vol. VI, pages 192-193.

62 Case No. 8616, final Order dated March 2, 1983, page 13.

LG&E's use of NOAA's published 1951-80 degree day data[63] as a "current" 30-year average ignores the impact that any recent temperatures may have had in defining normal degree days. The Commission is concerned that it may bias that information which is being considered as the standard for temperature normality.

In Exhibit 2 of his direct testimony, Mr. Ryan constructed 95 percent confidence intervals around the NOAA 1951-1980 30-year means. He asserts that since the annual total degree days and most of the monthly degree days fall outside of the confidence interval, the entire test year must be normalized for abnormal weather. In LG&E's effort to demonstrate that test year weather was abnormal, Mr. Ryan stated:

> Q. Since temperature is a random variable, can't you employ a statistical procedure to determine whether or not actual temperatures were statistically different from the historical average?
>
> A. Yes. This basically would involve the construction of a confidence interval around the mean of the weather variable. If the number of degree days actually incurred during the test period falls outside the confidence interval limits, they can be considered statistically different from the average.[64]

Though LG&E has used a confidence interval as a standard for testing normality, LG&E did not use the confidence interval for temperature adjustment purposes. Mr. Ryan adjusted each month's actual billing cycle temperature-sensitive load to a mean-determined temperature-sensitive load instead of to a

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63 Climatography of the United States No. 81 (By State), Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1951-80, Kentucky.

64 Ryan Prepared Testimony, page 6.

temperature-sensitive load determined by the boundaries of a range of acceptable values constructed around the mean.

The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound.

After determining normal weather and the departure of test year weather from normal, the methodology proposed by LG&E to determine weather-normalized sales involves estimating two components of total energy usage: baseload and temperature-sensitive load. LG&E's actual calculation of the weather normalization adjustment begins by determining the number of customers in each class for each month of the test year, as well as billing cycle days and billing-cycle degree days for each month of the test year. Billing cycle days were defined by Mr. Ryan to be the average number of days in all of LG&E's 21 billing districts for each month during the test year. Billing-cycle degree days were then defined to be the average number of degree days in each billing period for each month.

The Commission is concerned with the calculations of both billing cycle days and billing-cycle degree days. Mr. Ryan indicated on cross-examination that other LG&E personnel were specifically responsible for the calculations[65] and that these calculations assume an average and are not tied to the beginning and ending dates of district billing cycles.[66] This method of determining billing-cycle degree day fails to properly match customer load and their corresponding bills, because each billing cycle has discrete beginning and ending dates with specific degree days and customers associated with that period. Additionally, since no attempt was made to weight the billing-cycle degree days by the percentage of total customers included within each billing district, the results using billing-cycle degree days are not representative of the temperature's affect on electricity usage across billing districts unless each cycle includes approximately the same number of customers per class, an assumption which cannot be confirmed by LG&E.[67] Due to these problems and the lack of supporting evidence, the Commission finds that the method used to convert calendar month days and degree days into billing cycle days and degree days is inaccurate.

The accuracy of the billing cycle calculations is critical because these results are used in the calculation of the final temperature adjustment. Inaccuracies contained in LG&E's billing cycle calculations, therefore, render LG&E's entire electric temperature normalization adjustment unreliable and unacceptable.

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65 Hearing Transcript, Volume V, page 14.

66 Ibid., page 145.

67 Hearing Transcript, Volume V, pages 146-147.

As previously stated, LG&E separated total mWh sales into only two components: baseload and temperature-sensitive load. Residential baseload has been derived from the company's load research data. LG&E determined the daily residential baseload per customer based on the average of the 5 lowest days of daily energy usage from a selected sample of load research customers. For the test year this was determined to be 16.6 KWH per residential customer per day. To determine monthly total residential baseload, the 16.6 was then multiplied by the number of customers in each test year month. This product was then multiplied by monthly-billing cycle days. For the commercial sector, a weighted-average baseload was determined, which includes weekend and weekday usages.

The actual temperature-sensitive load was calculated by simply subtracting the actual estimated baseload per customer from the actual total load per customer. The number of actual billing-cycle degree days was then divided into the actual temperature-sensitive load to obtain the actual energy use per customer, per degree day. Normal temperature-sensitive load was then determined by multiplying the actual energy use per customer, per degree day times the number of customers times the normal number of billing-cycle degree days in that month. This normal temperature-sensitive load was then subtracted from actual temperature-sensitive load to determine the mWh sales adjustment.

Further, LG&E, in adopting its adjustment methodology, has failed to follow previous Commission orders to consider other variables in addition to temperature when normalizing sales. The methodology chosen by LG&E neglects to consider other factors (i.e., personal income, employment, humidity, wind, etc.) that may affect test-year electricity usage. LG&E has recognized that other factors may affect electricity sales but has not incorporated any of these factors in this adjustment.[68] By ignoring these variables LG&E's methodology does not accurately determine the actual relationship of electricity sales to degree days.

In his testimony, Mr. Ryan acknowledges the strong relationship between electricity usage and degree days,[69] as determined by a simple econometric model. Further, Mr. Ryan states that LG&E "is fully aware that variables other than weather affect electricity usage."[70]

The econometric modeling of temperature normalization is widely used by both the electric utility industry and regulatory agencies. During cross-examination, Dr. Carl Weaver, witness for the AG, recommended that to determine temperature-sensitive load, ". . . you should use a regression analysis but include more than one independent variable . . ."[71] Mr. Ryan admitted on cross-examination that to verify that relationships between loads and degree days existed on a class basis, regression analysis would be required.[72] However for the purpose of verifying these

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68 Ibid., Volume V, page 92.

69 Ryan Prepared Testimony, Exhibit 5.

70 Ibid., page 15.

71 Hearing Transcript, Vol. X, page 34.

72 Ibid., Vol. V, page 140.

relationships, Mr. Ryan has ignored those statistical techniques and instead relied upon "eyeballing" the temperature-sensitive load figures.[73] The primary use of an econometric or regression model in weather normalization is to adjust test year sales, which is the intended purpose of a weather normalization adjustment. During cross-examination, Mr. Ryan stated that there was no question in his mind regarding the accuracy of the relationship between degree days and KWH sales because he has been working with weather data and has made the type of computer runs that support the relationship. However, he further stated that the Commission has not seen those computer runs and that other than his assertion that loads per degree day look reasonable, nothing has been filed in the record of this case which verifies the accuracy of that relationship.[74] The Commission cannot allow an adjustment of over $7 million on such a nonspecific basis. In any case, if LG&E desires to propose an electric temperature adjustment in future rate applications, it should develop a methodology that will accurately and appropriately match the random effects of weather to electricity consumption. Further, LG&E should provide adequate support to verify the accuracy and appropriateness of any model presented. The Commission will require that LG&E provide documentation, including adequate statistical analysis, sufficient to support the accuracy of the relationships in the methodology developed and submitted in subsequent rate cases.

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[73] Ibid., pages 141-142.

[74] Ibid.

Stephen J. Baron of Kennedy and Associates proposed an alternative electric weather normalization adjustment on behalf of KIUC. In discussing the adjustment proposed by LG&E, Mr. Baron criticized several aspects of LG&E's model and concluded that LG&E's methodology was ". . . not precise and cannot be verified as to whether it is correct using actual monthly data."[75] Mr. Baron further stated that he believed that the most appropriate method to develop class weather normalization adjustments was by developing regression models utilizing load research data. No such analysis was presented in this case and Mr. Baron, therefore, determined that using the aggregate system sales and weather data supporting Ryan Exhibit 5 to develop system-wide sensitivity coefficients was the most appropriate way to correct LG&E's proposed adjustment. Mr. Baron then used these system-wide coefficients to adjust LG&E's class-by-class sales, revenue and expense adjustments.

Mr. Baron has recognized several important flaws in LG&E's methodology and attempts to correct these in order to calculate a more representative electric weather normalization adjustment. Mr. Baron's proposed adjustment, however, does not correct the problems presented by LG&E's methodology. By using the system company-wide data supporting Ryan Exhibit 5 (which represents a test year which has been characterized as abnormal) and then interpreting these into class-by-class adjustments, Mr. Baron has

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[75] Baron Prepared Testimony, filed February 16, 1988, page 14.

incorporated in his model the same inaccuracies and problems he noted in LG&E's model.

The Commission, therefore, finds that LG&E's proposed electric temperature adjustment should be denied for the following reasons:

1. LG&E's definition of normal degree days is based on 30-year data for the period 1951-1980, which does not include data for the most recent 7 years, including the test year.

2. The critical billing cycle calculations are inaccurate and do not reflect the actual degree days on either an actual or historic basis.

3. LG&E adjusted to a mean rather than to a range determined by a confidence interval.

4. LG&E has recognized only one variable that affects consumption.

5. LG&E did not accurately determine the relationship of KWH sales to degree days. LG&E simply estimated baseload and assigned the difference between total KWH sales and baseload to temperature-sensitive load.

6. LG&E has neither supported all of the assumptions nor supported the accuracy of its model.

The Commission is of the opinion that the electric weather normalization adjustment proposed by KIUC should be denied. The Commission cautions that alternative adjustments that suffer from the same inadequacies as the adjustments they are meant to replace are unacceptable.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $5,389,668 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	$3,132,927
Pension Costs	34,698
Health Insurance	1,224,561
Dental Insurance	47,280
Group Life Insurance	148,914
Thrift Savings Plan	248,469
FICA Taxes	550,126
Unemployment Taxes:	
State	30,421
Federal	<26,728>
TOTAL	$5,390,668

Excluding the gas supply expense adjustment, the adjustment for labor and labor-related costs represents the largest adjustment to LG&E test-year operating expenses. In this case, as has been previously stated, the labor and labor-related costs are areas of concern for two reasons: the notice in Case No. 8924 that the Commission would analyze health insurance costs in LG&E's next rate case and the recommendations incorporated in the Management Audit regarding fringe benefits and work force considerations.

Wages and Salaries

LG&E proposed to increase wages and salaries by $3,132,927 in order to reflect wage increases granted during and subsequent to the test year. The first part of this adjustment reflects an increase of $784,852 to recognize the increases granted during the test year. The second part represents the increases granted in

October and November 1987, which results in an increase of $2,348,075. Generally, when utilities request adjustments to wages and salaries, a comparison is made between actual test year wages and salaries and a normalized or pro forma expense level. In this and recent proceedings, LG&E has not determined the adjustment to wages and salaries by the methodology described above. Mr. Fowler testified that LG&E did not follow this methodology because LG&E's test-year labor costs include overtime, shift differentials and other items.[76] Mr. Fowler further stated that LG&E was trying to compare wages on a straight-time basis, that overtime was not included in the adjustment and that the adjustment was very conservative.[77]

Mr. Kollen, on behalf of KIUC, agreed with the first part of the wage adjustment but recommended that the second part be denied in that it represents increases granted outside the test year.

LG&E's wages and salaries consist of various components including overtime pay, shift pay, and straight-time labor. Since LG&E has adjusted only the straight-time component, the Commission does agree that the adjustment is conservative. The Commission also recognizes that the second part of the proposed adjustment is based upon increases granted subsequent to the test period. However, the Commission has, in some circumstances, allowed adjustments of this nature for various reasons. Allowing this adjustment will provide a more accurate matching of wage expense to the

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76 Hearing Transcript, Vol. III, page 130.

77 Ibid.

future rates which are intended to recover those wages. Additionally, the Commission notes that in Case No. 8616, which used a test year ended June 30, 1982, the Commission allowed LG&E to pass on wage increases granted in October and November 1982.[78] Therefore, the Commission is of the opinion that the full amount of the proposed adjustment to wages and salaries should be accepted.

Even though LG&E has adjusted only one component of wages and salaries, the Commission is concerned with LG&E's inability to provide the actual test year expense for each component of wages and salaries inasmuch as such information is necessary to accurately determine an adjustment to wages and salaries. During cross-examination, Mr. Fowler indicated that LG&E does not completely maintain the payroll records by employee classes[79] and in response to Commission data requests stated that,

> The automated payroll file by employee category is constantly changing as employees are added, deleted or transferred between categories and the data for prior periods is not retained. Thus, the annualized straight-time salaries of employees by categories can be determined for current employees, but such a calculation cannot be made for prior periods.[80]

LG&E is encouraged to incorporate the ability to determine the separate components of wages and salaries in the Management Information Systems being developed. The Commission, in future LG&E rate cases, will review the adjustments proposed for wages and

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78 Case No. 8616, final Order dated March 2, 1983, page 23.

79 Hearing Transcript, Vol. III, page 131.

80 Response to the Commission Order dated January 15, 1988, Item No. 8.

salaries while considering the actual test year-end levels of each element.

Group Life Insurance

LG&E proposed an adjustment of $148,914 to increase test-year operating expenses as a result of changes in the premium allowance for nonunion employees and to reflect the increased life insurance premiums resulting from the labor increase allowed in this case. In response to Item No. 16(d), page 10 of the Commission's Order dated November 12, 1987, LG&E provided the calculations to normalize the union and nonunion portions of this adjustment. The insurance benefit is equal to 125 percent of annual salary and the rate per $1,000 of insurance is $.59 for both categories of employees. For all employees, LG&E pays 100 percent of the premium on the first $5,000 of insurance. Prior to April 1, 1987, LG&E paid 75 percent of the premium for insurance in excess of the first $5,000 for all employees; however, on that date, LG&E, in accordance with the nonunion employees' benefit improvement package, began paying, for nonunion employees, 100 percent of the premium in excess of the first $5,000.

The adjustment proposed by LG&E reflects the change instituted in April for the nonunion employees; however, for simplicity, the calculation for union employees does not reflect the fact that LG&E pays 100 percent of the first $5,000 of insurance.[81] The Commission is of the opinion that the Group Life Insurance adjustment should be modified as determined in Appendix

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81 Response to the Commission Order dated December 23, 1987, Item No. 21, page 1.

B to this Order and as discussed below. The union employees' portion of the adjustment is calculated in a manner which does reflect that LG&E pays 100 percent of the premium for the first $5,000 of insurance and 75 percent of the amount over the first $5,000. Additionally, as previously discussed in the preceding Management Audit section of this Order, the nonunion employee portion has been calculated in the same manner as the union employees in order to recognize LG&E's benefit level prior to April 1, 1987. These changes result in a reduction of $40,534 to LG&E's proposed $148,914 adjustment. The Commission will, therefore, allow an increase in test-year operating expenses of $108,380 to reflect the increased costs associated with group life insurance.

Unemployment Taxes

LG&E proposed an adjustment to increase the expenses associated with federal and state unemployment taxes by $3,693. In his direct testimony, Mr. Fowler indicated that the adjustment resulted because of a higher wage base subject to these taxes; however, the decrease in the federal unemployment tax rate offset the increased wage rate and resulted in a negative adjustment for federal unemployment taxes.[82] As shown in Item No. 69(d)(1), the proposed adjustment relating to state unemployment taxes increases expenses by $30,421, while the adjustment related to federal unemployment taxes resulted in a decrease of $26,728.[83]

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82 Fowler Prepared Testimony, page 10.

83 Response to the Commission Order dated November 12, 1987.

In determining the amount of the adjustment, LG&E multiplied the base wage subject to unemployment tax by the total employees as of September 22, 1987 and multiplied this product by the applicable tax rate. LG&E provided the total number of employees at the end of several payroll periods in response to a Commission Information Request.[84] In that response, LG&E indicated that there were 3,920 employees as of September 6, 1987, which is the payroll period nearest the end of the test period. During cross-examination, Mr. Fowler indicated that the level of employees used in the adjustment was based on the September 22, 1987 payroll period because that was the approximate date the calculation was performed.[85] Additionally, Mr. Fowler stated that this calculation utilized a 0.6 percent federal unemployment tax rate in anticipation of a proposed change in that rate. Ultimately the change was not effected, thereby leaving the tax rate at 0.8 percent.

The Commission is of the opinion that it is more appropriate to use the number of employees in the payroll period nearest the end of the test year and the federal tax rate actually in effect in the calculation of this adjustment. Therefore, the Commission has, in Appendix C, recalculated this adjustment using 3,920 as the base number of employees and 0.8 as the federal unemployment tax rate. This recalculation results in increases to the test-year federal and state unemployment tax expense of $8,914 and

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84 Ibid., dated January 15, 1988, Item No. 14(c).

85 Hearing Transcript, Vol. III, page 136.

$21,573, respectively. The net effect is an increase to test-year operating expense of $30,487.

Thrift Savings Plan

LG&E proposed an adjustment to increase the test-year operating expense by $248,469 to reflect the normalized expense associated with the thrift savings plan instituted April 1, 1987 in the nonunion employee benefit improvement package. As previously discussed in the Management Audit section, the Commission has disallowed the expenses associated with this item. Therefore, the Commission has reduced operating expense by $180,668 which represents the actual test year expense associated with the thrift savings plan.

Health Insurance

LG&E proposed an adjustment of $1,224,561 to increase the test year level of health insurance expense. Testimony regarding this adjustment was presented by Mr. Hancock. Mr. Hancock also addressed the measures taken by LG&E to control medical benefit costs in response to the final Order in Case No. 8924.

As noted previously in the Management Audit section of this Order, the Commission will allow the proposed increase relating to the expense for the actual health insurance plans, but will not allow LG&E to include the expense relating to the cash incentive payments. According to Item No. 16(d), page 8,[86] the actual test year expense for health insurance was $7,781,922. This amount included $196,408 relating to the cash incentive payments. The

[86] Response to the Commission Order, dated November 12, 1987.

remaining $7,585,514 was subtracted from the pro forma operating expense relating to the actual insurance plans of $8,810,075 to arrive at the proposed adjustment of $1,224,561. The Commission, after reflecting the $196,408 decrease associated with the cash incentive payments, has increased the test-year operating expenses by $1,028,153 to recognize the increased health insurance costs.

Adjustment to Annualize Year-End Electric Volumes of Business

John Hart, Vice-President of Rates and Economic Research for LG&E, proposed an adjustment to reflect the increased costs associated with serving the level of customers at the end of the test year. The proposed adjustment, as amended by Mr. Hart, increased test-year operating revenues by $3,531,357 and test-year operating expenses by $1,860,852. The net effect is a proposed increase in test-year operating income of $1,675,005.

To determine the adjustment to operating revenue, the excess of customers served at test year-end over the test-year average customers was multiplied by an average revenue per customer. The average revenue per customer was determined using the actual revenues from sales to ultimate consumers adjusted to reflect the present rates for a full year, the transfers between rate schedules and normal temperatures. The Commission has previously determined that the proposed electric temperature normalization adjustment should be denied. Therefore, the proposed adjustment to electric operating revenues has been increased to $3,627,565 as calculated by the Commission to reflect the disallowance of the adjustment for normal temperature.

To determine the adjustment to operating expenses, Mr. Hart calculated a cost per KWH of electricity and multiplied that cost by the excess of test year-end customers over test-year average customers. As Mr. Hart explained during cross-examination, this is a traditional calculation made by LG&E[87] which has previously been accepted by the Commission. In performing the calculation in this manner, LG&E has treated all operation and maintenance expenses as variable costs, costs that will increase proportionately with each additional KWH sold. LG&E has not provided conclusive evidence that this is an accurate relationship of all operating expenses to KWH sales. As Mr. Hart admitted during cross-examination, customer accounting expenses, customer service and information expenses, and some portion of administrative and general expenses would vary with the number of customers and not with KWH sales.[88] In response to an information request, LG&E stated that an argument could be made for calculating the expense adjustment based on the company's operating ratio.[89] During cross-examination, Mr. Hart indicated that this approach was not used because he was being conservative in his approach and that his approach had been used for a number of years by LG&E.[90]

The Commission is of the opinion that the approach used by LG&E does not provide an accurate determination of the increase in

87 Hearing Transcript, Vol. I, page 194.

88 Ibid., Vol. VI, pages 194-195.

89 Response to the Commission Order dated January 15, 1988, Item No. 24.

90 Hearing Transcript, Vol. VI, page 200.

the level of expenses associated with serving additional customers and that it would be more appropriate to use an adjusted operating ratio. The Commission has accepted similar methods to adjust expenses to reflect year-end customers for other companies under its jurisdiction. An appropriate ratio of expenses to sales for use in this case should be 39.84 percent. The calculation of this ratio and the expense adjustment is included in Appendix D of this Order. In determining this ratio, actual test year wages and salaries have been subtracted from actual test year operation and maintenance expenses. It is not appropriate to include wages and salaries in this calculation because the amount of those costs to be included in future rates has previously been adjusted and reflects test year-end employees and post-test-year wage rates. Additionally, the amount of sales to other utilities, which is a net amount, has been deducted from total actual electric operating revenues.

The Commission is of the opinion that this method more accurately reflects the relationship of expenses to sales than the approach used by LG&E. Therefore, the Commission finds that the adjustment to LG&E's electric operating and maintenance expenses should be an increase of $1,445,222. The net effect of this adjustment is a decrease to test-year operating expenses of $2,182,343 or $507,338 above the net amount proposed by LG&E. The Commission advises LG&E that this issue will be considered in future rate proceedings.

Provision for Uncollectible Accounts

LG&E proposed an increase of $250,000 to the test year provision for uncollectible accounts based on its analysis of the appropriate total annual provision. The total provision and the increase were allocated between electric and gas based on the percentage of gross revenues from ultimate consumers for the preceding calendar year. While the Commission finds the proposed increase acceptable, it is concerned about LG&E's use of an allocation method based on revenues instead of actual electric or gas uncollectible account charge-off history. The amounts recorded for electric and gas provisions for uncollectible accounts were not based on the history of uncollectible charge-offs because LG&E did not maintain records of charge-offs by department.[91] LG&E should develop and maintain a record of actual uncollectible charge-offs by department and should utilize that information in adjusting the provision for uncollectible accounts in future rate proceedings.

Depreciation Expense

LG&E proposed to increase depreciation expense by $2,408,809 in order to annualize the test year expense. Of the total adjustment, $2,197,774 was for electric and $211,035 was for gas. Included in the gas depreciation calculations was the depreciation expense for gas underground storage property. The depreciation for this portion of the gas plant was computed using a rate of 5.05 percent. As has been discussed in the section of this Order

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91 Response to the Commission Order dated December 23, 1987, Item No. 40.

relating to retirements of SDRS and gas plant, LG&E revised its depreciation rates for gas underground storage property in order to recover the losses incurred when it abandoned three underground storage fields.[92] If LG&E had computed annual depreciation expense using a rate of 3.37 percent, which was in use before the abandonment, there would be a reduction of $536,972 in gas plant depreciation.[93] Because the Commission has decided to treat the abandonment loss as extraordinary, the use of the higher depreciation rate is unnecessary. The Commission has reduced the test-year depreciation expense for the gas plant by $325,937 to reflect the rate of 3.37 percent on gas storage plant. The Commission has accepted the electric depreciation adjustment. Therefore, the total increase to depreciation expense allowed herein is $1,871,837.

Advertising Expense

LG&E proposed to remove $267,278 from its test-year advertising expenses, which represented expenditures which were not allowable for rate-making pursuant to 807 KAR 5:016. The prohibited advertising expenses include promotional, political, and institutional advertising. At the hearing, LG&E witness, Mr. Wilkerson, introduced a schedule of promotional advertising expenses which had not been included in LG&E's original

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92 Hearing Transcript, Vol. IV, page 21.

93 Response to KIUC Second Data Request, filed February 1, 1988, Item No. 16.

adjustment, and indicated these expenses should also be removed.[94] The additional promotional advertising expenses totaled $52,960. The Commission has accepted both of the advertising adjustments proposed by LG&E, and has reduced advertising expenses by a total of $320,238. The $267,278 in reductions to the electric and gas operations are accepted as proposed; in addition, the $52,960 has been allocated, $40,779 to electric and $12,181 to gas, based on LG&E's reported allocation methods for such costs.

Membership Dues

During the test year, LG&E paid membership dues to the Edison Electric Institute ("EEI") of $164,390 and to the Coalition for Environmental Energy Balance ("CEEB") of $5,800. In addition, LG&E paid $20,760 to EEI as its annual assessment for an acid precipitation study. LG&E included these expenditures in adjusted test-year operating costs.

LG&E was asked to enumerate the benefits of EEI membership and provide any cost-benefit analysis performed concerning membership. LG&E was also asked to provide a breakdown of the EEI dues based on EEI activities. In its responses, LG&E indicated it had not and could not perform cost-benefit analysis of its membership.[95] While providing a listing of benefits, the listing was general in nature and did not document any specific benefits

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94 Hearing Transcript, Vol. VIII, pages 185-191 and Wilkerson Exhibit 1.

95 Response to the Commission Order dated December 23, 1987, Item No. 36(d), page 2 of 7.

received by LG&E's ratepayers.[96] LG&E was asked to describe the nature of CEEB and why it was a member. LG&E provided a general description of the activities of CEEB and explained that the CEEB activities were compatible with LG&E's mission.[97] However, LG&E's responses did not indicate any direct benefits to its ratepayers from CEEB membership.

The Commission is aware that the payment of membership dues to organizations such as EEI and CEEB have received differing regulatory treatment across the country in recent years. The Commission takes notice of two recent cases which involved situations similar to the one the Commission faces in this case. In a case before the Missouri Public Service Commission, EEI dues were disallowed in their entirety because there was no way to quantify the benefits accorded ratepayers and shareholders from membership in the association.[98] In a case before the Massachusetts Department of Public Utilities, the assertion that EEI membership provided numerous and substantial benefits to electric ratepayers did not relieve a utility of its duty to prove that the dues represented a reasonable operating expense and the dues were disallowed.[99]

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96 Ibid., Item No. 36(c), pages 1 and 2 of 7.

97 Response to CAG First Data Request, filed February 8, 1988, Item No. 15.

98 Arkansas Power and Light Company, 74 PUR4th 36 (1986), Case Reference ER-85-265.

99 Western Massachusetts Electric Company, 80 PUR4th 479 (1986), Case Reference DPU 85-270.

In this case, LG&E has failed to show that its membership in EEI and CEEB is of direct benefit to its ratepayers. Therefore, the Commission has excluded all EEI and CEEB costs in the amount of $170,190 from allowable operating expenses for rate-making. This issue will be reconsidered in future cases if LG&E can document that the costs of membership dues provide a direct benefit to the ratepayers.

The Commission recognizes the growing concern in this country over the problems of acid rain. Studies, such as the one being performed by EEI, could provide valuable information in the resolution of this problem. The Commission finds that the EEI acid precipitation study could provide future benefits to LG&E and its ratepayers. Therefore, the Commission has included the $20,760 annual assessment as an allowable rate-making expense.

Excess Deferred Taxes - Tax Reform Act of 1986

In Case No. 9781, The Effects of the Federal Tax Reform Act of 1986 on the Rates of Louisville Gas and Electric Company, Order dated June 11, 1987, the Commission explored the issue of excess deferred taxes resulting from the change in tax rates under the Tax Reform Act. The Commission stated that the accelerated amortization of the unprotected excess deferred taxes would be considered in future rate proceedings.[100] In response to a data request LG&E provided the amount of unprotected excess deferred taxes available for accelerated amortization.[101] In addition, LG&E

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[100] Case No. 9781, final Order dated June 11, 1987, page 10.

[101] Response to the Commission Order dated December 23, 1987, Item No. 30.

provided a calculation of a deferred tax deficiency arising from an increase in the state corporate tax rate. LG&E took the position that the federal excess deferred taxes should be offset by the state deficiency in accordance with the Commission Order in Case No. 8616.[102] Mr. Kollen, on behalf of KIUC, has recommended that the unprotected excess deferred taxes as of August 31, 1987 be offset by the same proportion of the state tax deficiency and be returned to the ratepayers as a 1-year credit to base rates.[103] At the hearing, LG&E indicated that the original information filed could violate the normalization requirements of the Tax Reform Act and subsequently filed an amended calculation.

The Commission is of the opinion that the unprotected excess deferred taxes of $4,749,500 as of August 31, 1987,[104] the test year-end, should be offset by the full state tax deficiency of $4,385,600 and amortized over 5 years for rate-making purposes. The effect of this decision is an annual reduction in income tax expense in the amount of $72,780. This amount has been allocated to gas and electric operations in proportion to the existing deferred tax reserve after the adjustment for early retirements with $6,703 allocated to gas operations and $66,077 to electric operations. The rate base has been increased by a like amount to recognize the first year's amortization. LG&E should transfer the excess and deficiency to separate accounts in order that they can

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102 Ibid.

103 KIUC Brief, May 9, 1988, pages 30-33.

104 Response to Hearing Data Request, filed May 9, 1988, Excess Deferred Federal Income Taxes as of December 31, 1987.

be readily identified in future rate proceedings. The Commission is of the opinion that this method is in keeping with the position established in Case No. 8616[105] and does not represent a change of Commission practice.

Management Audit Adjustments

LG&E proposed an adjustment to reflect the recovery of the cost of the Management Audit over a 3-year period. The effect of this adjustment is to increase operating expenses by $194,000. The proposed adjustment allocates $44,620 to gas operations and $149,380 to electric operations. Pursuant to KRS 278.255, the agreement between LG&E, RM&A/Scott and the Commission stated that the cost of the audit would be an allowable expense for rate-making purposes. The Commission, therefore, has accepted the adjustment as proposed by LG&E.

The $2,475,092 test-year cost of the management information systems discussed in the Management Audit section of this Order has been allocated by the Commission to gas and electric and operations in the same proportion as the cost of the Management Audit. The adjustments decrease the test-year operating expenses in the gas department by $569,271 and by $1,905,821 in the electric department.

As previously discussed in the Management Audit section, the Commission has disallowed $258,040 associated with the test-year cost of open management audit recommendations. The test-year cost of $1,477,900 of these recommendations was detailed by LG&E in

[105] Case No. 8616, final Order dated March 2, 1983, pages 20-21.

response to a data request.[106] Commission review of this response indicates that $1,166,900 of these costs have been capitalized or included in the disallowed cost of the management information systems. An additional $52,960 was included by Mr. Wilkerson at the hearing as additional disallowed advertising and has been included in that adjustment, as amended. The remaining $258,040 is based on the following recommendations as detailed in the response to a data request and has been allocated to gas and electric operations as indicated below:[107]

Recommendation	Gas	Electric	Total
V-5	$11,969	$ 40,071	$ 52,040
XI-3	3,220	10,780	14,000
XIV-1	-0-	12,000	12,000
XVI-1, 2, 3	53,000	-0-	53,000
XVIII-1, 2, 3, 5	29,210	97,790	127,000
TOTAL	$97,399	$160,641	$258,040

Recommendations XIV-1 and XVI-1, 2, and 3 have been identified as specific to either gas or electric operations. The other recommendations were allocated to gas and electric operations in the same manner as the cost of the Management Audit.

The total effect of these adjustments is to decrease operating expenses by $2,539,132. The decrease in gas operations is $622,050 and in electric operations is $1,917,082.

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[106] Response to the Commission Order dated January 15, 1988, Item No. 1.

[107] Ibid.

Storm Damage Expenses

LG&E has proposed an adjustment to amortize, over a 3-year period, unrepresentative storm damage expenses incurred during July 1987. This proposed adjustment would decrease test year operations and maintenance expenses by $976,896.

Listed below are actual storm damage expenses for the past 5 calendar years as indicated by LG&E:[108]

Year	Amount
1982	$ 442,375
1983	448,465
1984	332,705
1985	1,670,904
1986	722,355

The actual test-year storm damage expenses were $3,189,909, an amount greater than in any 3 of the past 5 calendar years. After the proposed adjustment is reflected, the test year would still include $2,213,013 in storm damage expenses.

Mr. Fowler of LG&E stated at the hearing that over a 2-week period LG&E's service area was hit by a series of very extensive and unusual storms.[109] Mr. Fowler indicated in his prepared testimony that the company considers these expenses to be legitimate, reimbursable costs.[110] However, LG&E recognized that the recovery of costs of this magnitude might overstate the level of expenses during a normal 12-month period and has, therefore,

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[108] Response to the Commission Order dated December 23, 1987, Item No. 25(e).

[109] Hearing Transcript, Vol. III, page 116.

[110] Fowler Prepared Testimony, page 12.

proposed an adjustment to amortize these costs over a 3-year period.[111]

During redirect examination, Mr. Fowler stated:

> If the Commission takes the position that you cannot recover these costs, we can certainly reduce these costs very easily by allowing the customer to stay off five weeks instead of two weeks or one week, by doing the repairs during normal business hours with our regular employees.[112]

Mr. Fowler further stated during recross-examination that he believed that LG&E should make every effort to restore service but should the Commission exclude costs incurred for the benefit of the customer, there is a point beyond which the company would have to consider the extent of its efforts. He further stated that if ". . . the stockholders are going to have to eat the expenses, there would become a point where maybe a day or two delay would not seem unreasonable."[113]

In determining a reasonable level of operating expenses and an appropriate rate of return, the Commission considers both the risks of the shareholders and the appropriate cost of service to be borne by a utility's ratepayers. In the present case, LG&E argues that the expenses were incurred for the benefit of the ratepayers. However, the stockholders were unable to earn a return until service had been restored. Clearly, expeditious restoration of service is of benefit to both ratepayers and stockholders.

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111 Ibid.

112 Hearing Transcript, Vol. IV, page 54.

113 Ibid., pages 145-146.

The random occurrence of severe storm damage cannot be accurately predicted. This can be seen from the historical calendar year experience noted above. LG&E has focused on only 1 month of the test year in determining that the $1,465,344 abnormal expense incurred in July should be amortized. Mr. Fowler indicated during cross-examination that the 1985 storm damage expense of $1,670,904 was abnormal.[114] Yet, he proposed to include $1,724,565 as an ongoing or normal level of storm damage expenses in addition to the amortization of the abnormal July expense of $488,448. The Commission is of the opinion that the test year should include only a reasonable level of storm damage expenses. The proposed adjustment does not render the test period expense representative for rate-making purposes, but projects a level of expense that is clearly abnormal in relation to the historical storm damage expense as indicated by LG&E. The Commission has, on past occasions, determined a reasonable level of expenses by utilizing a historical average and reaffirms that policy. In this case, the average of the test year and the 4 previous calendar years results in an allowable average of $1,272,868 and a decrease in test year expenses of $1,917,041. The Commission finds that this does not deny recovery but merely establishes a reasonable level of expense for the period in which rates will be in effect. In addition, LG&E should continue to make every effort to restore service as soon as possible.

[114] Ibid., Vol. III, pages 121-123.

Interest Synchronization

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. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the extraordinary property losses discussed in this Order. Using the adjusted capital structure allowed herein, the Commission has computed an interest adjustment of $122,093 which results in a reduction to income taxes of $47,353.

After applying the combined state and federal income tax rate of 38.785 percent to the accepted *pro forma* adjustments, the Commission finds that combined operating income should be increased by $25,109 to $118,883,427.

The adjusted net operating income is as follows.

	Gas	Electric	Total
Operating Revenues	$52,020,765	$460,363,195	$512,383,960
Operating Expenses	44,532,659	348,967,874	393,500,533
ADJUSTED NET OPERATING INCOME	$ 7,488,106	$111,395,321	$118,883,427

RATE OF RETURN

Capital Structure

Mr. Fowler proposed an adjusted end-of-test-year capital structure containing 46.17 percent debt, 9.40 percent preferred stock, and 44.43 percent which reflect the adjustments discussed in the Capital section of this Order.

Dr. Weaver, witness for the AG, proposed a capital structure containing 46.20 percent debt, 9.47 percent preferred stocks, and 44.33 percent common equity. As stated in the Capital section of this Order, the difference between Dr. Weaver's proposed capital structure and Mr. Fowler's was the result of the date used by Dr. Weaver in determining capital structure and in the adjustments to reflect discounts on preferred stock and common equity.[115]

Mr. Kollen, witness for KIUC, proposed a capital structure containing 48.55 percent debt, 9.89 percent preferred stock and 41.56 percent common equity based on his proposed adjusted capital.

The Commission has determined LG&E's adjusted capital structure for rate-making purposes to be as follows:

	Amount	Percent
Debt	$ 614,484,032	46.17
Preferred Stock	125,170,510	9.40
Common Equity	591,346,711	44.43
	$1,331,001,253	100.00

In determining the capital structure, the Commission has accepted the adjustments to capital proposed by LG&E and has used the capital ratios reflected as of September 1, 1987. As previously stated, the test-year-end JDIC has been allocated to each component of the capital on the basis of the ratio of each component to total capital, excluding JDIC, as proposed by LG&E and in accordance with past Commission treatment of this item. In

[115] Weaver Prepared Testimony, pages 35-36.

addition, the total capital has been reduced by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. The losses have been allocated on the basis of the ratio of each capital component to the total capital.

Cost of Debt

Mr. Fowler proposed a cost of 8.09 percent for preferred stock which was based on the embedded rate as of August 31, 1987.[116] Dr. Weaver recommended an 8.02 percent rate for preferred stock. The difference between Mr. Fowler's and Dr. Weaver's proposed cost of preferred stock was that Dr. Weaver did not reduce the book value of the outstanding preferred stock by the issuing expense.[117] The Commission is of the opinion that issuance costs should be reflected in the cost of preferred stock. Therefore, the Commission is of the opinion that the reduction in book value of the outstanding preferred stock by the issuing expense is proper and that the 8.09 percent rate reflects the true costs of the preferred stock to LG&E.

Mr. Fowler further testified that LG&E's end-of-test year embedded cost of long-term debt was 7.62 percent and reflects adjustments for the retirement of $12,000,000 of First Mortgage Bonds, Series due September 1, 1987, a sinking fund requirement of $250,000 of 1975 Series A pollution control bonds, and the replacement of 1982 Series B (9.40 percent) pollution control

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116 Fowler Prepared Testimony, page 17.

117 Weaver Prepared Testimony, page 36.

bonds with 1987 Series A (6.876 percent) bonds.[118] Dr. Weaver proposed a cost of debt of 7.51 percent which was based upon October 31, 1987 data.[119] The Commission is of the opinion that long-term cost of debt is 7.62 percent based on the end-of-test-year adjusted data.

Cost of Equity

Dr. Charles E. Olson, President of H. Zinder and Associates and witness for LG&E, recommended a return on equity in the range of 13.75 to 14.25 percent.[120] Dr. Olson's recommendation was based on a discounted cash flow ("DCF") analysis of LG&E. In addition, he utilized both a risk premium analysis and a DCF study of nine electric companies as a check on his estimate of LG&E's DCF cost of equity.

In the LG&E DCF analysis, Dr. Olson used (1) a dividend yield of 7.78 percent based on a dividend of $2.66 and a 6-month high/low average stock price of $34.188; and (2) an estimated dividend growth rate of 5.0 to 5.5 percent based on LG&E's 5-year earnings per share growth rate.[121] This resulted in an overall DCF estimate of 12.78 to 13.28 percent. Dr. Olson performed a risk premium analysis as his first check on his LG&E's DCF estimate. The "premium" that investors required over bond yields was estimated at 3.5 percent. This was higher than the 2.6 percent

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118 Fowler Prepared Testimony, Exhibit 5.

119 Weaver Prepared Testimony, page 37.

120 Olson Prepared Testimony, page 30.

121 Ibid., pages 17-22.

premium from Dr. Olson's source of information, a Paine Webber Mitchell Hutchins, Inc. publication titled "Electric Utility Industry - Electric Utility Analyst Survey" (April 19, 1985).[122] The 3.5 percent risk premium was added to LG&E's current bond yield of 10.1 percent resulting in a 13.6 percent required return. Dr. Olson's second check was based on a DCF analysis of nine electric utility companies and resulted in an average return on equity of 12.79 to 13.29 percent.[123] In addition, Dr. Olson increased his estimates by approximately 8.0 percent to allow for flotation costs and market pressure to arrive at his recommended range of 13.75 to 14.25 percent.[124]

Mr. Royer of LG&E recommended that a return on equity in the range of 13.8 to 14.8 percent is necessary to maintain the financial integrity of LG&E and to fund internal growth at 4.0 to 5.0 percent.

Dr. Weaver recommended a cost of equity in the range of 11.5 to 12.5 percent based on a DCF analysis and used the earnings/price ratio approach as a means to gain additional information. He applied the DCF model to LG&E and a group of four comparable companies using 1987 data and 1978-1980 historical data. Dr. Weaver developed his growth rates using the earnings retention ratio times return on equity (b x r) method. Dr. Weaver's results showed a cost of equity of 10.33 percent for the comparable

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122 Ibid., pages 25-26.

123 Ibid., page 28.

124 Ibid., page 29.

companies and 10.20 percent for LG&E in 1987, and a 13.58 percent and 11.58 percent for 1978-1980, respectively. Dr. Weaver's earnings/price ratio approach averaged 13.04 percent and were higher than his 1987 DCF results, but were closer to the 1978-1980 DCF estimates on the return on equity. Dr. Weaver recommended that no allowances be made for flotation costs or market pressure.

Dr. Jay B. Kennedy, a principal in Kennedy and Associates and witness for KIUC, recommended an 11.75 percent return on equity with a range of 11.34 to 12.21 percent. Dr. Kennedy's proposal was based on a DCF analysis on LG&E. He also performed a DCF analysis on a comparison group of five utilities and a risk premium analysis for verification. His ranges on return on equity were from the results of his DCF analysis and showed LG&E with an average 11.34 percent return on equity and the comparison group with an average 12.21 percent return on equity.[125] Dr. Kennedy's risk premium estimate was based on the difference between the comparison group's average bond yield of 10.02 percent for the July 1987 to December 1987 period, and the DCF cost of equity of 12.21 percent for the comparison group. This risk premium of 2.19 percent was then added to LG&E's long-term debt of 9.82 for a risk premium cost of equity of 12.01 percent.[126] Dr. Kennedy made no allowances for flotation costs or market pressure; however, he suggested that any future costs of issuing common stock be

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125 Kennedy Prepared Testimony, page 40.

126 Ibid., page 41.

measured and recovered externally as a cost of providing service, and levelized over a 30-year period at the weighted cost of capital.

Mr. Kinloch stated that LG&E's rate of return should be 12.0 percent assuming that LG&E no longer receives CWIP, but only 11.0 percent if they are allowed to continue receiving CWIP. Mr. Kinloch's recommendation was based on "current trends from around the nation on recent cases."[127]

The Commission has an obligation to allow LG&E an opportunity to earn a rate of return which will allow it to continue to maintain its financial integrity. In making its determination, the Commission finds that Dr. Olson has basically ignored his own data on growth estimates as provided in his testimony and, therefore, rejects his recommendation of a 14.0 percent return on equity in that it is in excess of an investor's required rate of return. In addition, the Commission also finds that Dr. Weaver's use of the b x r method, if earnings have been inadequate in the past, can understate the growth rate component and, thus, the investor's required return in the DCF analysis. The lower growth rate derived from the b x r method results in a lower allowed return which could result in lower earnings and a lower retention ratio and then a still lower growth rate component and so on. A downward trend could develop and thus weaken the financial integrity of LG&E. The Commission further finds that Dr. Kennedy's failure to give proper weight for the current volatile economic conditions

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127 Kinloch Prepared Testimony, page 13.

results in an understatement of the investor's required rate of return.

Therefore, the Commission having considered all of the evidence, including recent volatile economic conditions, is of the opinion that a return on equity in the range of 12.25 to 13.25 percent is fair, just, and reasonable. A return on equity in this range would allow LG&E to attract capital at a reasonable cost to insure continued service and provide for necessary expansion to meet future requirements, and also would result in the lowest possible cost to ratepayers. A return of 12.75 percent will best meet the above objectives.

Rate of Return Summary

Applying rates of 7.62 percent for debt, 8.09 percent for preferred stock, and 12.75 percent for common equity to the capital structure approved herein produces an overall cost of capital of 9.94 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $13,463,256 to produce a rate of return of 12.75 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes, there is an overall revenue deficiency of $21,993,394 which is the amount of additional revenue granted herein. 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 $132,346,683. A breakdown between gas and electric operations of the required operating income and the increase in revenue allowed herein is as follows.

	Total	Gas	Electric
Net Operating Income Found Reasonable	$132,346,683	$13,103,981	$119,242,702
Adjusted Net Operating Income	118,883,427	7,488,106	111,395,321
Net Operating Income Deficiency	13,463,256	5,615,875	7,847,381
Additional Revenue Required	21,993,394	9,174,017	12,819,377

The additional revenue granted herein will provide a rate of return on the net-original cost rate base of 9.98 percent and an overall return on total capitalization of 9.94 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $644,797,735. These operating revenues include $469,555,007 in electric revenues and $175,242,728 in gas revenues.

OTHER ISSUES

"Benchmark" Treatment of Operation and Maintenance Expenses

KIUC proposed a reduction of test-year operating and maintenance expenses totaling $25,771,000, which it claimed reflected the excessive expense growth above inflation and sales growth experienced by LG&E. The amount of reduction was determined utilizing a "benchmark" calculation presented by KIUC witness, Mr. Kollen. Mr. Kollen took the pro forma operation and maintenance expenses for the test year in LG&E's last general rate case and multiplied the amounts by an overall growth factor to arrive at a benchmark level of operation and maintenance expenses.[128] These figures were compared to the pro forma operation and maintenance expenses for the current test year, and the difference calculated. Mr. Kollen's analysis was restricted to non-fuel operation and maintenance expenses. In his prepared testimony, Mr. Kollen indicates that the $25,771,000 in operation and maintenance expenses over his benchmark calculation clearly shows that the growth in those expenses is out of control.[129] He advocates that the Commission adopt some form of cost containment, like the benchmark, as an incentive for LG&E.[130]

During the hearing, Mr. Kollen was cross-examined extensively about his benchmark approach. Mr. Kollen frequently referred to the Florida Public Service Commission ("Florida PSC") utilizing a benchmark approach similar to his proposal. While Mr. Kollen testified that the Florida PSC uses a benchmark approach in all general rate proceedings, he could not cite a rule, regulation, practice, or order which required such a filing.[131] While advocating the benchmark as a means of total operation and maintenance expense containment, Mr. Kollen readily accepted the fact that some functional areas of operation and maintenance expenses could continue to increase in exchange for reduction in

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128 Kollen Prepared Testimony, Exhibit LK-5 and Hearing Transcript, Vol. XI, pages 91-92.

129 Kollen Prepared Testimony, page 14.

130 Ibid., page 18.

131 Hearing Transcript, Vol. XI, pages 97-98.

other areas.[132] In computing the overall growth factor, Mr. Kollen used the change in the sales growth in his calculations although his testimony was that the Florida PSC uses the change in the customer growth.[133]

In its brief, KIUC stated that,

> . . . there is substantial evidence [emphasis added] indicating that the requested level of O & M expense is excessive even when given a liberal recognition of inflation and sales growth. In the absence of specific data [emphasis added] provided by the Company, the Commission should determine the reasonable level of recurring operation and maintenance expense using a benchmark methodology similar to that developed and utilized by the Kentucky Commission two cases ago.[134]

The Commission does not understand how there can be "substantial evidence" while at the same time be an "absence of specific data." In the case which KIUC has referenced to support the benchmark approach, the increase to wages and salaries was denied because of an evaluation of existing economic conditions; therefore, the Consumer Price Index was used as a substitute for the percent of wage increase allowed for rate-making purposes.[135] Thus, the example referred to differs significantly from the proposed benchmark as put forth by KIUC.

The benchmark approach to establishing a fair and reasonable level of expenses may be a useful tool in instances where the data is not available to make specific adjustments, or in abbreviated

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132 Ibid., pages 100-102.

133 Ibid., page 103.

134 KIUC Brief, filed May 9, 1988, page 47.

135 Case No. 8616, final Order dated March 2, 1983, pages 22-23.

filings or annual earnings adjustment cases allowed by some state regulatory bodies where time constraints are present. However, the Commission in its general rate proceedings, applies the standards of known and measurable as well as fair and reasonable in making adjustments to the historical test period. In this case, many adjustments have been made to reduce historical test year expenses where costs were deemed to be excessive, non-recurring, or otherwise inappropriate for rate-making purposes. The Commission believes that this approach is much more accurate and results in a more reasonable level of operating expenses. The case presented by KIUC on this issue is not conclusive. The Commission has decided not to use the benchmark approach proposed by KIUC in this general rate proceeding.

Gas Cost of Service

In accordance with the Commission's Order of May 29, 1987 in Administrative Case No. 297, An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers, the Company prepared and filed a fully distributed, embedded gas cost of service study. The study's sponsor, Randall Walker, LG&E's Coordinator of Rates and Tariffs, described the methodology in his testimony,

> In order to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each class makes to the overall return on net gas rate base, costs were first assigned to functional groups, then classified as to demand, commodity, or customer-related, and finally, allocated to the classes of service.[136]

[136] Walker Prepared Testimony, page 2.

The study shows that the residential class is being subsidized by all other rate classes of gas service.[137] According to this Exhibit, the adjusted return for the test year for residential service is a negative 0.79 percent, for nonresidential service, 11.93 percent, Fort Knox, 16.5 percent, and seasonal off-peak Rate G-6, 66.34 percent. LG&E stated in its brief that "such an imbalance is undesirable and should be improved."[138] As a result, LG&E is proposing rates which will result in a more equitable recovery of costs, thus reducing the differential in class rates of return. The Residential Intervenors contend that the reason for the residential class's negative return is that the study overstates the costs incurred by the residential class.[139] One example of overstated costs offered by the Residential Intervenors involves the method in which the costs of distribution mains are allocated. LG&E uses the zero-intercept methodology to classify the costs of distribution mains as either demand or customer related. "This methodology again disproportionately assigns costs to the residential class based on a theoretical system design which has no basis in reality."[140] Also critical of LG&E's use of the zero-intercept methodology was the DOD whose witness, Suhas P. Patwardhan, conversely charges that "use of the Company method

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137 Ibid., Exhibit 1, page 4.

138 LG&E Brief, May 9, 1988, page 64.

139 Residential Intervenors Brief, May 9, 1988, page 14.

140 Ibid., pages 14-15.

will result in favorable treatment for small usage customers as opposed to large usage customers."[141] Mr. Patwardhan feels that the use of a minimum-system method would result in a more favorable rate of return performance from large users such as Fort Knox.

The Commission is convinced that the zero-intercept method is theoretically sound and less subjective than the minimum system method, in which a minimum size main must be subjectively chosen in order to determine the customer component.

For the purpose of determining cost causation, LG&E separates its customers into four classes of service, Rate G-1-residential, Rate G-1-nonresidential, Fort Knox and Rate G-6-Seasonal Off-Peak service. This particular breakdown of rate classes evokes this criticism by the KIUC:

> Although LG&E has presented a "cost-of-service study," it is not appropriate because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service.[142]

KIUC further contends that the Company's study is contrary to the Commission's guidelines set forth in its Order in Administrative Case No. 297. On pages 42-43 of that Order, the following guidelines are stated, "The Commission prefers that the (cost of service) studies be disaggregated to the greatest extent possible."

Pursuant to its criticism of LG&E's gas cost of service study, KIUC, through its witness Kenneth Eisdorfer, presented an

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141 Patwardhan Prepared Testimony, page 7.

142 KIUC Brief, May 9, 1988, page 87.

alternative study. Mr. Eisdorfer's study disaggregates the Non-residential Rate G-1 category, used by LG&E, into Commercial G-1, Industrial G-1 (Sales), and Industrial G-1 (Transportation). Further, he disaggregates LG&E's Rate G-6 into Sales and Transportation classes of service. His study allocates gas stored underground exclusively to sales service. Otherwise, all cost assignment methodologies are identical to LG&E's.[143]

The Commission is of the opinion that KIUC's assertion that the Company did not fully disaggregate the various classes of service is a valid concern. The Commission will require LG&E to specifically address this issue in the gas cost of service study it files in its next rate case.

Except as described above, the Commission finds that the gas cost of service filed by LG&E provides an adequate starting point for rate design and should be used as the guide for the allocation of revenues to the customer classes.

Electric Cost of Service

LG&E filed an embedded time-differentiated cost of study that used a base-intermediate-peak ("BIP") method to allocate production and transmission demand related costs to costing periods and to customer classes. The methodology used by LG&E was essentially the same as has been used in the last two rate cases with the exception that some of the demand allocators were adjusted to account for temperature-sensitive demand. James W. Kasey,

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[143] Eisdorfer Prepared Testimony, page 11.

Coordinator of Rate Research for LG&E, sponsored the embedded cost of service study.

There was considerable concern expressed by the Residential Intervenors, County and CAG with the results of the electric cost of service study. Mr. Kinloch indicated his opposition to LG&E's use of the zero-intercept method for allocating distribution system costs between energy and customer related costs. He stated, "The use of a minimum system calculation assumes that all customers are the same, and that each customer contributes equally to the minimum system requirement."[144] He further contended that customers living in older neighborhoods were closer to generation stations with more fully depreciated infrastructure and contribute less to costs of the distribution system. Mr. Kinloch concluded that the minimum distribution grid costs should be allocated based on energy and recovered through a KWH charge.[145]

The Residential Intervenors expressed concern with LG&E's proposal to include weather normalization adjustment in its cost of service study. The Residential Intervenors contend that they are doubly affected by weather normalization because "the company increased the residential contribution to system peak demand over actual test year contribution to reflect a lower than 'normal' demand,"[146] plus "the company's proposed weather normalization reduced the revenues attributed to the residential class by $8.5

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[144] Kinloch Prepared Testimony, page 29.

[145] Ibid., page 30.

[146] Residential Intervenors Brief, page 12.

million."[147] Thus, the residential class rate of return is reduced to 6.25 percent for the adjusted test year which was below the system average of 8.67 percent. Therefore, the Residential Intervenors proposed that the, ". . . company cost of service study should not be used to assign a greater percentage of any increase to the residential than that assigned to the system as a whole."[148]

The Commission in its Order in Case No. 8924 accepted LG&E's proposed cost of service study's methodology. The Commission continues to be of the opinion that LG&E's BIP methodology is appropriate. Furthermore, the Commission will continue to accept the zero-intercept methodology for the allocation of distribution costs between customer and demand components of the cost of service study. This method is theoretically superior to the alternative proposed by the Residential Intervenors.

Though the Commission is of the opinion that LG&E's cost of service methodology is acceptable, the Commission has serious concerns with the class rate of return results. In this case, LG&E's witness testified that, ". . . the summer and winter system peaks used in this analysis were temperature normalized,"[149] and ". . . several of the demand allocation factors were normalized for the effects of temperature . . ."[150] In a previous section of

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[147] Ibid., page 13.

[148] Ibid., page 13.

[149] Kasey Prepared Testimony, Exhibit 1, page 7.

[150] Ibid., page 11.

this Order the Commission rejected the temperature normalization adjustment. The use of temperature normalized allocators and the temperature normalization adjustment of the winter and summer peaks result in improper allocations of costs to various classes, distorting class rate of return. Therefore, the Commission will reject the cost of service study for use as the basis for the allocation of revenues to the classes. Instead, the Commission will allocate the increase in revenue to each rate class in proportion to its overall increase in rates.

RATE DESIGN

Street Lighting

The City expressed concern about the financial impact of the proposed increased cost of the 400-watt mercury vapor street light with a wood pole. The Commission understands the concerns of the City and recognizes that inequities exist in the tariffs for mercury vapor street lights and the high pressure sodium vapor lights because the rates do not currently reflect cost of service. The Commission agrees with the analysis that LG&E prepared to reflect the movement toward cost-based rates in the street lighting structure. As the Commission has reduced the requested revenue increase by LG&E in this case, the Commission has also adjusted the rates of individual units in the street lighting tariff, which reflects a gradual movement to cost-based rates. The Commission advises the City and LG&E that LG&E should again analyze and update its street lighting tariff in its next rate case.

Disconnect and Reconnection Charge/Monthly Customer Charge

Mr. Kinloch, representing the County and the CAG, stated that the low income customers would be adversely affected by the proposed increases in the disconnect and reconnection charge ("fee") and the monthly customer charge ("charge").[151] Mr. Kinloch stated that the fee applies generally to the bills of the customers that are least able to pay the fee; that the fee is a cost of doing business; that all utilities, such as Louisville Water Company in Louisville and Jefferson County, do not charge such a fee; and that new customers are not charged a hookup fee. The Commission has considered the testimony of Mr. Kinloch and recognizes that this type of a fee by its nature will affect customers experiencing financial difficulties. The fee recovers a cost of business created by a minority of customers. Although Louisville Water Company may not exercise its right to charge this fee, that right is still in its rules and regulations. The Commission does not find that disconnect/reconnect service charges upon the customers creating the need for these services to be comparable to the provision of hookup service at no charge to every customer. While the Commission is sensitive to the concerns of those experiencing financial hardship, it recognizes that a fee of this type allocates costs to cost causers and is a fair and reasonable component of an electric utility rate design. The Commission has and will continue to consider the effects of this charge. In this case, the Commission has adjusted the proposed $4

151 Kinloch Prepared Testimony, page 22.

increase to $2 to reflect the approximate percent of decrease of LG&E's overall requested increase. The fee is to increase from $12 to $14.

Mr. Kinloch recommended that the monthly residential customer charge for electric service be reduced below the current monthly charge of $3.16 to $2.35 and the residential rate design be changed to a flat rate for the winter months and an inverted block rate for the summer months. Similarly, Mr. Kinloch recommended that the proposed monthly customer charge for gas services be reduced from $5.50 to $3.85. The Commission has accepted the cost of service methodologies proposed by LG&E for the Electric and Gas Divisions but has rejected the proposed weather normalization included in the Electric Division's cost of service study. Mr. Kinloch did not propose a complete cost of service analysis for either the Electric or Gas Division, and the proposed inverted block rate for electric is not a cost-based rate. The rate design as proposed by LG&E has been accepted in the past by the Commission.

The Commission is of the opinion that LG&E's proposed residential rate design appropriately reflects its costs and is fair to all parties. Therefore, considering the objectives of cost-based rates and rate continuity, the Commission has relied on LG&E's proposal in determining approved residential rates.

Off-System Sales

George Gerasimou, witness for KIUC, recommended that the Commission investigate the feasibility of flowing total revenue associated with off-system sales through the monthly fuel adjustment clause ("FAC").[152] He did not propose any adjustment to revenues or expenses in this case related to his proposed treatment of off-system sales. FAC revenues and expenses are reviewed in 6-month hearings under the Commission's regulation 807 KAR 5:056. That regulation is under review in Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056. The Commission is of the opinion that any revision to the FAC regulation should have been presented to the Commission for review in that case.

Revenue Increase Allocation

LG&E based its proposed allocation of revenue increase on its cost of service studies. The Commission has previously rejected the proposed electric cost of service analysis for reasons stated elsewhere in this Order; therefore, the Commission will allocate the allowed electric revenue increase in the proportions of the revised normalized class revenue to the total revised normalized revenue, as illustrated below.

	Revised Normalized Revenue	Percent	Allocation of Revenue Increase
Residential	$172,914,195	38.313	$ 4,900,514
General Service	66,230,541	14.675	1,877,040
Large Commercial	89,790,252	19.895	2,544,717
Large Industrial	91,697,158	20.317	2,598,694
Special Contracts	24,078,953	5.335	682,386
Street and Outdoor Lighting	6,611,828	1.465	187,384
Total Sales Customers	$451,322,927	100.000	$12,790,735
Other Electric Revenue	5,412,703		28,642
Total Electric Operating Revenue	$456,735,630		$12,819,377

152 Gerasimou Prepared Testimony, page 6, A16.

The Commission has accepted the gas temperature normalization and the other revenue adjustments as proposed by LG&E in the $166,068,711 total normalized gas operating revenues. The reduction in the allowed Gas Division revenue increase from the proposed revenue increase will be allocated among those rate classes that LG&E proposed revenue increases. LG&E proposed an extremely large percent increase to the monthly customer charge. The Commission is of the opinion that the proposed customer charges should be reduced to maintain rate continuity. Therefore, all of the reduction in proposed gas revenue increase is allocated to the customer charge. The allocation of the revenue increase is as follows.

Rate Class	Normalized Revenue	Allocation of Revenue Increase
Rate G-1		
Total Residential	$ 89,443,656	$ 8,394,853
Total Non Residential	55,672,127	2,085,578
Rate G-6	13,601,930	<1,324,103>
Rate G-7	106,520	<10,953>
Rate G-8		-0-
Fort Knox Contract	5,783,136	-0-
Total Sales and Transportation	$164,607,369	$ 9,145,375
Other Revenues	1,461,342	28,642
Total Gas Operating Revenues	$166,068,711	$ 9,174,017

Economic Development Rate

LG&E, through its witness, Fred Wright, has proposed an Economic Development Rate ("EDR") to be administered as a rider to LG&E's Large Commercial Rate - LC, Large Commercial Time-of-Day

Rate - LC-TOD, Industrial Power Rate - LP, and Industrial Power Time-of-Day Rate - LP-TOD. Mr. Wright described the purpose of this proposed rate in the following statements:

> LG&E strives to broaden the base of customers over which to spread its fixed costs, in order to keep its retail gas and electric rates as low as practicable so as to remain competitive for new business . . . The EDR is designed to stimulate the creation of new jobs and capital investment both by encouraging existing large commercial and industrial companies to remain in the area and to expand, and by making it more attractive for new companies to move into our service area.[153]

The proposed rate offers companies in the above rate classes, who increase their electric load demand by at least 1,000 Kilowatts over the base year load demand, a reduction to the billing demand during the 8 monthly billing periods from October through May in accordance with the following table:

Time Period	Reduction to Billing Demand
First 12 Months	50%
Second 12 Months	40%
Third 12 Months	30%
Fourth 12 Months	20%
Fifth 12 Months	10%
After 60 Months	0%

For purposes of this rider, the base year is defined as the most recent 12-month calendar year period ending before the effective date of this rider.

Mr. Wright further explains that, "Incentive rates are becoming increasingly common in utility rate tariffs in areas against which the Louisville area must compete."[154] In addition, Mr.

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153 Wright Prepared Testimony, page 3.

154 Wright Prepared Testimony, page 5.

Wright testified that "it (EDR) should not contribute unnecessarily to the Company's future capacity requirements but, rather should improve the Company's electric system load and capacity factors by encouraging growth in a customer class that has a higher load factor."[155] Several parties in this proceeding expressed concern with LG&E's proposed EDR. Mr. Kinloch testified that, although he was not opposed to economic development and the creation of jobs, he is concerned about the mechanism by which LG&E has proposed to address these issues -- the EDR. The first point of concern he raised is that "the EDR rate is below cost of service pricing."[156] Secondly, he expressed apprehension about the potential for success of the EDR and concern with the lack of formal evaluation proposed by LG&E. Finally, Mr. Kinloch addresses the effect, he feels, the EDR will have on LG&E's low-income customers. "While there may be some benefit for a younger low-income customer who is unemployed, the EDR rate will provide absolutely no benefit for elderly customers on fixed incomes."[157] Mr. Kinloch likens the EDR to a lifeline rate proposed for industry instead of to the low-income customers. He suggests that the Commission approve the EDR only if LG&E offers a lifeline rate to elderly customers on fixed incomes.

The Residential Intervenors, during the cross examination of Mr. Wright, raised the concern with the manner in which LG&E will

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155 Ibid., page 6.

156 Kinloch Prepared Testimony, page 45.

157 Ibid., page 47.

determine the normality of whether base year demand, above which an additional one megawatt will qualify an LC, LC-TOD, LP, or LP-TOD rate customer for the EDR. Specifically, they were concerned with whether there were unusual circumstances in the base year that would cause a customer's demand to be lower than it would normally be.[158] Mr. Wright responded that each qualifying customer must convince LG&E that he has created jobs and capital investment, and that no unusual circumstances exist in the base year. LG&E did not propose, nor does the EDR rider address, the mechanism by which either of these conditions will be satisfied.

Throughout the record in this case, LG&E has maintained a dual purpose in proposing the EDR: creating additional load, and creating new jobs and new capital investment. The Commission believes that the two purposes are complements. However, the Commission also believes that the concern raised by the intervenors, that LG&E has proposed no mechanism in its EDR to determine that both of these purposes are being addressed, is valid.

The Commission also finds merit with the following concerns raised by the intervenors and its Staff regarding the EDR:

1. The possibility that the EDR is priced below cost of service.

2. The lack of any formal evaluation by LG&E of the effects of the EDR if it is implemented.

3. The effect the EDR will have on LG&E's other ratepayers.

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158 Hearing Transcript, Vol. II, page 222.

4. The fact that the EDR rider does not specify how to determine if base year demand is abnormal or how to determine the effect of the EDR on job creation and capital investment.

5. Whether the EDR should be implemented via a tariff or by special contracts.[159]

There has been a substantial increase in the number of economic development/incentive rates filed with the Commission by both electric and gas utilities during the past year. The purpose of these tariffs, according to the utilities, is to increase the amount of energy sold and/or to expand the level of capital investment and employment in the sponsoring utility's service area. Though the rate designs may vary drastically by utility, they typically provide demand discounts for new and expanding industries within the utility's service area for some specified time period, typically 5 years.

At the current time, the Commission has before it, in addition to LG&E's proposed EDR rider, several economic development/incentive rate proposals. Each of the various tariffs and contracts will require a Commission decision for implementation. Because of the potential volume of tariff and contract filings and their impact on the utility and their customers, the Commission is of the opinion that a consistent policy should be developed on tariff filing and reporting requirements.

The Commission finds that the concerns raised by the parties in the instant case, the number of tariffs and contracts presently

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159 Hearing Transcript, Vol. II, pages 251-253 and 255-256.

under consideration, and the potential implications of these proposals necessitate that utilities which offer economic development/incentive rates to existing or potential customers must satisfy the following requirements, prior to Commission approval of the proposed rate:

1. Each utility should be required to provide an affirmative declaration and evidence to demonstrate that it has adequate capacity to meet anticipated load growth each year in which an incentive tariff is in effect.

2. Each utility should be required to demonstrate that all variable costs associated with the transaction during each year that the contract is in effect will be recovered and that the transaction makes some contribution to fixed costs. Furthermore, the customer-specific fixed costs associated with adding an economic development/incentive customer should be recovered either up front or as a part of the minimum bill over the life of the contract.

3. Each utility that offers an economic development rate should be required to document and report any increase in employment and capital investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.

4. Each utility that intends to offer economic incentive rates should be required to file a tariff stating the terms and conditions of its offering. Furthermore, each utility should be required to enter into a contract with each customer which specifies the minimum bill, estimated annual load, and length of

contracting period. No contract should exceed 5 years. All contracts shall be subject to the review and approval of the Commission.

5. Each utility should be required to include a clause in its contract that states that the tariff will be withdrawn when the utility no longer has adequate reserve to meet anticipated load growth.

6. Each utility should be required to demonstrate that rate classes that are not party to the transaction should be no worse off than if the transaction had not occurred. Under special circumstances, the Commission will consider utility proposals for contracts that share risk between utility shareholders and other ratepayers. However, if a utility proposes to charge the general body of ratepayers for the revenue deficiency resulting from the EDR through a risk-sharing mechanism then the utility will be required to demonstrate that these ratepayers should benefit in both the short- and long-run. In addition, at least one-half of the deficiency will be absorbed by the stockholders of the utility and will not be passed on to the general body of ratepayers. The amount of the deficiency will be determined in future rate cases by multiplying at least one-half of the billing units of the EDR contract(s) by the tariffed rate that would have been applied to customer(s) if the EDR contract(s) had not been in effect.

The Commission is of the opinion that these restrictions on economic development/incentive rates will provide a means for protecting other ratepayers while still providing LG&E, other utilities, and industrial development specialists the opportunity to use lower rates to attract industry.

Furthermore, the Commission is of the opinion and finds that the EDR rider proposed by LG&E is partially consistent with Requirement 4 above. However, the rider must be revised to include language making it completely consistent with all of the above requirements. Therefore, LG&E should withdraw the EDR rider in its present form and refile it within 30 days after all revisions have been made.

Cogeneration and Small Power Production Tariffs

Pursuant to the Order in Case No. 8566, Setting Rates and Terms and Conditions of Purchase of Electric Power from Small Power Producers and Cogenerators by Regulated Electric Utilities, LG&E filed tariffs reflecting its proposed avoided energy and capacity costs. Robert Lyon, Manager of System Planning and Budgets, sponsored the avoided cost studies and tariffs. In preparing estimates of avoided energy costs, LG&E used "its more detailed production costing model, PROMOD III, in place of the EBASCO model (MARCOST 80)." Similarly, in preparing estimates of avoided capacity costs, "computer models used in the Company's recent capacity expansion study were used, viz., EGEAS (Electric Generation Expansion Analysis System) and TALARR (Total and Levelized Annual Revenue Requirements)." Both models are widely accepted and used in the electric utility industry.

In preparing its estimate of avoided capacity costs, LG&E used, "[T]wo twenty-year strategic expansion plans . . ." One plan assumed qualifying facilities with 75,000 KW capacity with an availability of 70 percent and no capacity costs while the other plan did not. The use of Qualifying Facility ("QF") capacity by LG&E resulted in both cancellation and deferment of combustion turbine capacity in its 20-year planning cycle. The difference in the present worth of revenue requirements ("PWRR") between the two plans represented the avoided capacity costs of QF capacity since only the fixed costs of plant ownership were considered in the PWRR analysis. Using a levelized annual revenue requirement of $1,910,000 and assuming 70 percent availability and must run QF operational characteristics, Mr. Lyon proposed a capacity purchase payment of 4.15 mills per KWH. Finally, Mr. Lyon indicated that a QF would have to contract for 20 years to qualify for the proposed capacity purchase payment. In addition, LG&E proposed that each QF be required to post a bond to insure that capacity will be offered for the duration of the contract.

In preparing its avoided energy costs, LG&E used essentially the same method as it used in preparing its estimates in Case No. 8566. Using PROMOD III, LG&E estimated its avoided energy costs at 2.04 cents per KWH. Mr. Lyon indicated that LG&E would apply this avoided energy cost to all QF purchases regardless of whether it was under a 20-year contract or not. He further indicated that LG&E would update its estimates of avoided energy costs and its energy purchase rates annually, and avoided capacity costs and capacity purchase rates updates biannually. Finally, Mr. Lyon indicated that the revised rates would apply to all QF purchases.

The Commission is of the opinion and finds that the proposed rates resulting from the avoided costs are consistent with the

Commission's Order in Case No. 8566. Furthermore, the rates reflect LG&E avoided costs and should be adopted. However, the Commission does intend to continue to monitor LG&E bonding requirements to insure that the requirements do not discourage or hinder QF development.

Natural Gas Tariffs

KIUC proposes that LG&E's gas tariffs be revised to reflect the costs incurred by the utility in serving different customers.[160] KIUC states that the cost of service study LG&E has submitted is deficient "because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service."[161] KIUC states that the result of LG&E's revenue proposals for transportation customers will be to earn from these classes an excessive rate of return. KIUC's proposed solution is to utilize the cost of service study presented by its witness, Mr. Eisdorfer.

KIUC's conclusions are based upon the differences between its cost of service study and the one submitted by LG&E. The Commission discusses the two studies elsewhere in this Order in the section entitled Gas Cost of Service, wherein the Commission concludes that these issues raised by KIUC are a valid concern. However, the Commission has decided to have LG&E disaggregate the various classes of service more fully in the gas cost of service

160 KIUC Brief, filed May 9, 1988, page 87.

161 Ibid., page 86.

study it files in its next rate case. Therefore, it would be inappropriate to order any tariff changes the support for which would require a greater disaggregation between classes than that accepted by the Commission in LG&E's cost of service study.

KIUC also proposes that certain changes be made to LG&E's proposed tariff Rate T applicable to gas transportation service. KIUC states that the proposed language ". . . does not conform with Mr. Hart's representation . . . that transportation service provided under Rate T would be firm and that the language should be corrected by substituting the word "converted" for the word "reduction . . ."[162] KIUC also believes that certain language under the "availability" part of this tariff should be changed to conform to certain provisions in the Order issued in Administrative Case No. 297. Specifically, KIUC argues that the language should clearly state: LG&E has the obligation to tell a prospective transportation customer why it cannot transport gas; and the burden of proof is on LG&E to show that capacity does not exist on its system to transport gas.[163]

The Commission is of the opinion that the proposed language in LG&E's gas tariffs is sufficient to allow a prospective gas customer to understand the services offered and their terms and conditions. The Commission also finds that it is unnecessary for LG&E to substitute the word "converted" for the word "reduction" in the Rate T tariff. LG&E's proposed language allows its

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162 Hearing Transcript, Vol. VI, page 93.

163 Ibid., page 94.

transportation customers to receive transportation service under Rate T as long as LG&E's D-1 and D-2 billing demands from its pipeline supplier are reduced in an amount corresponding to the volumes of gas transported. The Commission understands KIUC's point to be that an end-user through its supplier may request a reduction or conversion of some portion of its supply in order to increase the amount of transportation it can utilize. LG&E agrees that an end-user may request either a reduction or conversion.[164] However, in either case, LG&E must receive a reduction in its billing demands which represent the reduced or converted sales volumes. Otherwise, LG&E's non-transportation customers would ultimately pay the billing demands for those sales volumes not purchased by such an end-user.

Regarding the "availability" section of the Rate T tariff, the Commission does not view the current language as relieving LG&E of its burden of proof. LG&E agrees with the points raised by KIUC.[165] However, the Commission is of the opinion that the language should be clarified to provide prospective transportation customers in a clearer understanding of LG&E's responsibilities. Therefore, LG&E should revise the language in the "availability" section of the Rate T tariff to more clearly comply with the Order issued in Administrative Case No. 297.

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164 Hearing Transcript, Vol. VI, pages 78-79.

165 Ibid., pages 85-86.

Effective Date of New Rates

LG&E's proposed rates were filed with an effective date of December 20, 1987. Pursuant to KRS 278.190(2), the Commission suspended the operation of the proposed schedules for a period of 5 months, until May 20, 1988. On May 19, 1988, LG&E filed a motion stating that if the Commission has not ruled on its rate application by May 20, 1988, LG&E would forego its right to place the proposed rates in effect subject to refund provided that the new rates when authorized will be made effective on May 20, 1988. None of the intervenors objected to this motion and the Commission granted it by Order issued May 20, 1988.

In accordance with that Order, the rates authorized herein are being made effective for service rendered on and after May 20, 1988. With respect to a surcharge to permit LG&E to recover the new rates from May 20, 1988 through the effective date of this Order, LG&E's motion proposed that the surcharge be applied to billings spread over an extended period of time not to exceed December 31, 1988. On June 20, 1988, the Commission received a letter from LG&E proposing that the surcharge be applied only to billings for one month. The Residential Intervenors notified the Commission on June 28, 1988 that it objected to LG&E's proposed modification. The Commission is of the opinion that LG&E should file a surcharge plan within 30 days from the date of this Order. All parties will then be afforded 15 days to file comments on the plan.

SUMMARY

The Commission, after consideration of the evidence of record and being advised, is of the opinion and finds that:

1. The rates in Appendix A are the fair, just, and reasonable rates for LG&E and will produce gross annual revenues based on adjusted test year sales of approximately $644,776,975.

2. The rate of return granted herein is fair, just, and reasonable and will provide for the financial obligations of LG&E with a reasonable amount remaining for equity growth.

3. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

4. The proposed EDR tariff rider should be withdrawn and resubmitted for review when the revisions discussed herein have been made.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved for service rendered by LG&E on and after May 20, 1988.

2. The rates proposed by LG&E be and they hereby are denied.

3. The proposed EDR tariff rider shall be resubmitted when LG&E has made necessary revisions.

4. Within 30 days from the date of this Order, LG&E shall file with the Commission its revised tariff sheets setting out the rates approved herein.

5. LG&E shall file a surcharge plan within 30 days of the date of this Order and intervenors shall have until 15 days thereafter to file comments.

Done at Frankfort, Kentucky, this 1st day of July, 1988.

By the Commission

ATTEST:

Forrest M. Skaggs

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988.

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: $3.25 per meter per month.

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	6.023¢ per Kwh
Additional kilowatt-hours per month	4.717¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month	6.593¢ per Kwh

WATER HEATING RATE
(RATE SCHEDULE WH)

RATE: 4.761¢ per kilowatt-hour.

Minimum Bill $2.05 per month per heater

GENERAL SERVICE RATE*
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.85 per meter per month for single-phase service
$7.70 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 6.454¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.232¢ per Kwh

Minimum Bill:

The minimum bill for single-phase service shall be the customer charge.

The minimum bill for three-phase service shall be the customer charge; provided, however, in unusual circumstances where annual kilowatt-hour usage is less than 1,000 times the kilowatts of capacity required, Company may charge a minimum bill of not more than 98 cents per month per kilowatt of connected load.

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE RATE SCHEDULE GS

RATE:

For all consumption recorded on the separate meter during the heating season the rate shall be 4.726¢ per kilowatt-hour.

Minimum Bill:

$6.90 per month for each month of the "heating season." 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)

Applicable:

In all territory served.

Availability:

This schedule is available for alternating current service to customers whose monthly demand is less than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $16.90 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	$7.25 per Kw per month	$5.61 per Kw per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.33 per Kw per month	$8.42 per Kw per month

Energy Charge:

All kilowatt-hours per month 3.272¢

LARGE COMMERCIAL TIME-OF-DAY RATE

Availability:

This schedule is available for alternating current service to customers whose monthly demand is equal to or greater than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $17.20 per delivery point per month

Demand Charge:

Basic Demand Charge

Secondary Distribution	$3.68 per Kw per month
Primary Distribution	$1.99 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge

Summer Peak Period	$6.66 per Kw per month
Winter Peak Period	$3.54 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 3.272¢ per Kwh

Winter-Peak Period is defined as weekdays, except holidays as recognized by company, from 6 AM to 10 PM local time, during the 8 monthly billing periods of October through May.

INDUSTRIAL POWER
(RATE SCHEDULE LP)

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is less than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage.

RATE:

Customer Charge: $41.70 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
All kilowatts of billing demand	$8.99 per Kw per month	$7.02 per Kw per month	$5.86 per Kw per month

Energy Charge:

All kilowatt-hours per month 2.832¢ per Kwh

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

Applicable:

In all territory served.

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is equal to or greater than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage. Company reserves the right to decline to serve any new load of more than 50,000 kilowatts under this rate schedule.

RATE:

Customer Charge: $42.55 per delivery point per month

Demand Charge:

Basic Demand Charge:	
Secondary Distribution	$5.26 per Kw per month
Primary Distribution	$3.30 per Kw per month
Transmission Line	$2.10 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge:	
Summer Peak Period	$5.51 per Kw per month
Winter Peak Period	$2.92 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 2.832¢ per Kwh

Summer-Peak Period is defined as weekdays, except holidays as recognized by Company, from 9 AM to 11 PM local time, during the 4 monthly billing periods of June through September.

Winter-Peak Period is defined as weekdays, except holidays as recognized by Company, from 6 AM to 10 PM local time during the 8 monthly billing periods of October through May.

Power Factor Provision

The monthly demand charge shall be decreased .4% for each whole one percent by which the monthly average power factor exceeds 80% lagging and shall be increased .6% for each whole one percent by which the monthly average power factor is less than 80% lagging.

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATES:

Overhead Service Mercury Vapor	Rate Per Light Per Month
100 watt*	$6.92
175 watt	7.89
250 watt	8.98
400 watt	11.03
400 watt floodlight	11.03
1000 watt	20.38
1000 watt floodlight	20.38
High Pressure Sodium Vapor	
150 watt	$9.89
150 watt floodlight	9.89
250 watt	11.73
400 watt	12.55
400 watt floodlight	12.55
Underground Service Mercury Vapor	
100 Watt - Top Mounted	$12.00
175 Watt - Top Mounted	12.83
High Pressure Sodium Vapor	
100 Watt - Top Mounted	$14.14

* 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 $1.62 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:

TYPE OF UNIT

Overhead Service	Support	Rate Per Light Per Year
100 Watt Mercury Vapor (open bottom fixture)(1)	Wood Pole	$74.57
175 Watt Mercury Vapor	Wood Pole	88.03
250 Watt Mercury Vapor	Wood Pole	100.76
400 Watt Mercury Vapor	Wood Pole	121.45
400 Watt Mercury Vapor (2)	Metal Pole	174.02
400 Watt Mercury Vapor Floodlight	Wood Pole	121.45
1000 Watt Mercury Vapor	Wood Pole	228.43
1000 Watt Mercury Vapor Floodlight	Wood Pole	228.43
150 Watt High Pressure Sodium	Wood Pole	107.36
150 Watt High Pressure Sodium Floodlight	Wood Pole	107.36
250 Watt High Pressure Sodium	Wood Pole	129.36

400	Watt High Pressure Sodium	Wood Pole	136.21
400	Watt High Pressure Sodium Floodlight	Wood Pole	136.21
	Underground Service		
100	Watt Mercury Vapor Top Mounted		121.65
175	Watt Mercury Vapor Top Mounted		133.73
175	Watt Mercury Vapor	Metal Pole	179.67
250	Watt Mercury Vapor	Metal Pole	192.87
400	Watt Mercury Vapor	Metal Pole	228.09
400	Watt Mercury Vapor	Alum. Pole	228.09
400	Watt Mercury Vapor on State of KY Aluminum Pole		137.14
100	Watt High Pressure Sodium Top Mounted		133.73
250	Watt High Pressure Sodium Vapor	Metal Pole	245.48
250	Watt high Pressure Sodium Vapor	Alum. Pole	245.48
250	Watt High Pressure Sodium Vapor on State of KY Aluminum Pole		127.19
400	Watt High Pressure Sodium Vapor	Metal Pole	264.89
400	Watt High Pressure Sodium Vapor	Alum. Pole	264.89
1500	Lumen Incandescent (3)	8-1/2' Metal Pole	99.01
6000	Lumen Incandescent (3)	Metal Pole	131.99

(1) Restricted to those units in service on 5/31/79
(2) Restricted to those units in service on 1/19/77
(3) Restricted to those units in service on 3/1/67

STREET LIGHTING ENERGY RATE
(RATE SCHEDULE SLE)

RATE:

4.021¢ per kilowatt-hour

TRAFFIC LIGHTING ENERGY RATE
(RATE SCHEDULE TLE)

RATE:

5.327¢ per kilowatt-hour

Minimum Bill:

$1.45 per month for each point of delivery.

INTERRUPTIBLE SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Availability:

This rider is available for interruptible service to any customer whose interruptible demand is at least 1,000 kilowatts.

Contract Demand:

The contract shall be for a given amount of firm demand which shall be billed at the appropriate standard rate schedule demand charge. Any excess monthly demands above this firm demand shall be considered as interruptible demand.

Rate:

The monthly bill for service under this rider shall be determined in accordance with the provisions of Rate LC, Rate LC-TOD, Rate LP or Rate LP-TOD, except there shall be an interruptible demand credit determined in accordance with one of the following categories of interruptible service:

Interruptible Service Categories	Maximum Annual Hours of Interruption	Monthly Demand Credit ($/Kw/Mo)
1	150	1.18
2	200	1.57
3	250	1.94

The interruptible demand credit shall be applied to the monthly billing demand in excess of the firm contract demand (but not less than 1,000 kilowatts) determined in accordance with the billing demand provision under the applicable rate schedule, except in the case of service under Rate LC-TOD or Rate LP-TOD. The interruptible credit shall be applied to the billing demands as determined for the peak periods only.

Interruption of Service:

The Company will be entitled to require customer to interrupt service at any time and for any reason upon providing at least 10 minutes prior notice. Such interruption shall not exceed 10 hours duration per interruption.

Penalty for Unauthorized Use:

In the event customer fails to comply with a Company request to interrupt either as to time or amount of power used, the customer shall be billed for the monthly billing period of such occurrence at the rate of $15.00 per kilowatt of monthly billing demand. Failure to interrupt may also result in the termination of the contract.

Term of Contract:

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

Applicability of Terms:

Except as specified above, all other provisions of Rate LC, Rate LC-TOD, Rate LP and Rate LP-TOD shall apply.

SUPPLEMENTAL OR STANDBY SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Rate:

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, that the monthly bill shall in no case be less than an amount calculated at the rate of $5.61 per kilowatt applied to the contract demand.

Special Terms and Conditions:

d. In the event customer's use of service is intermittent or subject to violent fluctuations, the Company will require customer to install and maintain at his own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-1

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-II

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
ARICO ALLOYS AND CARBIDE SPECIAL CONTRACT

Demand Charge

Primary Power (28,500 Kw)	$11.37 per Kw per month
Secondary Power (Excess Kw)	$5.69 per Kw per month
Demand Credit for Primary Interruptible Power (24,500 Kw)	$1.94 per Kw per month
Energy Charge All KWH	2.005¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

Demand Charge

$11.02 per Kw of billing demand per month

Energy Charge

2.128¢ 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 $6.24 per Kw per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All Kw of Billing Demand $8.42per Kw per month

Energy Charge: All Kwh per month 2.742¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

$7.53 per Kw of billing demand per month

Energy Charge

2.261¢ per Kwh

GENERAL RULES

Charge for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Residential and general service customers may request and be granted a temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

GAS SERVICES

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through PGA 8924-R.

GENERAL GAS RATE
G-1

Curtailment Rules

Delete specific reference.

Availability:

Available for general service to residential, commercial and industrial customers.

Rate:

Customer Charge:

$4.55 per delivery point per month for residential service
$9.25 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	10.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	37.802¢

Off-Peak Pricing Provision:

The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by 5.0 cents per 100 cubic feet during the 7 monthly off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

Availability:

Available to any customer who takes gas service under Rate G-1 and who has installed and in regular operation a gas burning summer air conditioning system with a cooling capacity of three tons or more. The special rate set forth herein shall be applicable during the 5 monthly billing periods of each year beginning with the period covered by the regular June meter reading and ending with the period covered by the regular October meter reading.

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	5.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.802¢

All monthly consumption other than "Summer Air Conditioning Consumption" shall be billed at the regular charges set forth in Rate G-1.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheets No. 12, 13 and 14 of this Tariff.

SEASONAL OFF-PEAK GAS RATE
G-6

Curtailment Rules

Delete specific reference.

Availability:

Available during the 275-day period from March 15 to December 15 of each year to commercial and industrial customers using over 50,000 cubic feet of gas per day who can be adequately served from the Company's existing distribution system without impairment of service to other customers and who agree to the complete discontinuance of gas service for equipment served hereunder and the substitution of other fuels during the 3-month period from December 15 to March 15. No gas service whatsoever to utilization equipment served hereunder will be supplied or permitted to be taken under any other of the Company's gas rate schedules during such 3-month period. Any gas utilization equipment on customer's premises of such nature or used for such purposes that gas service thereto cannot be completely discontinued during the period from December 15 to March 15 will not be eligible for service under this rate, and gas service thereto must be segregated from service furnished hereunder and supplied through a separate meter at the Company's applicable standard rate for year-around service. This rate shall not be available for loads which are predominantly space heating in character or which do not consume substantial quantities of gas during the summer months.

Rate:

Customer Charge: $20.00 per delivery point per month

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Minimum Bill:

The customer charge.

Prompt Payment Provision:

The monthly bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within 15 days from date.

RATE FOR UNCOMMITTED GAS SERVICE
G-7

Rate:

Charge Per 100 Cubic Feet:

Distribution Cost Component	4.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	31.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Incremental Pricing:

Delete from Tariff.

DUAL-FUEL OFF-PEAK GAS SPACE HEATING RATE
G-8

Service to be supplied under G-1.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE
G-8

Service to be supplied under G-1.

GAS TRANSPORTATION SERVICE/STANDBY
RATE TS

Availability:

Available to commercial and industrial customers served under Rates G-1 and G-6 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on the Company being able to retain or secure adequate standby quantities of natural gas from its supplier. In addition, transportation service hereunder shall be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

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	$1.0820	$0.5300
Pipeline Supplier's Demand Component	.4671	.4671
Total	$1.5491	$0.9971

The "Distribution Charge" applicable to G-1 monthly quantities in excess of 100 Mcf shall be reduced by $.50 per Mcf during the 7 off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component:

Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's quarterly Gas Supply Clause.

Standby Service:

Company will provide standby quantities of natural gas hereunder for purposes of supplying customers' requirements should customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in the Company's applicable rate schedule under which it sells gas to customer.

Receipts and Deliveries:

Customer shall not cause quantities of gas to be delivered to Company's system which exceed the quantities delivered to the customer's place of utilization by more than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof.

GAS TRANSPORTATION SERVICE
RATE T

Applicable:

In all territory served.

Availability:

Available to commercial and industrial customers served under Rate G-7 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any such transportation service hereunder shall be conditioned on the Company being granted a reduction in D-1 and D-2 billing demands by its pipeline supplier corresponding to the customer's applicable transportation quantities. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

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.

Distribution Charge Per Mcf: $0.43

Receipts and Deliveries:

Customer will deliver or cause to be delivered daily and monthly quantities of natural gas to Company's system which correspond to the daily and monthly quantities delivered hereunder by Company to customer's place of utilization and, in no case, shall the variation in quantities be greater than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(1) Service under this rider shall be performed under a written contract between customer and Company setting forth specific arrangements as to volumes to be transported by Company for customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily

volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

(3) In no case will Company be obligated to supply greater quantities hereunder than those specified in the written contract between customer and Company.

(4) Volumes of gas transported hereunder will be determined in accordance with Company's measurement as set forth in the general rules of this Tariff.

(5) All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline supplier.

(6) Company will have the right to curtail or interrupt the transportation or delivery of gas to any customer hereunder when, in the Company's judgment, such curtailment is necessary to enable Company to maintain deliveries to residential and high priority customers or to respond to an emergency.

(7) Should customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such customer requirements.

Applicability of Rules:

Service under this Rider is subject to Company's rules and regulations governing the supply of gas service as incorporated in this Tariff, to the extent that such rules and regulations are not in conflict with nor inconsistent with the specific provisions hereof.

GAS SUPPLY CLAUSE
GSC

Applicable to:

All gas sold.

Gas Supply Cost Component (GSCC): (PGA) 8924-R)

Gas Supply Cost		27.043¢
Gas Cost Actual Adjustment (GCAA)		0.241
Gas Cost Balance Adjustment (GCBA)		(0.269)
Refund Factors (RF) continuing for 12 months from the effective date of each or until Company has discharged its refund obligation thereunder:		
Refund Factor Effective August 1, 1987 from 8924-O	(0.020)	
Refund Factor Effective November 1, 1987 from 8924-P	(0.013)	
Total of Refund Factors Per 100 Cubic Feet		(0.033)
Total Gas Supply Cost Component Per		26.982¢

The monthly amount computed under each of the rate schedules tp which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each 3-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each 3-month period determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected total purchases at the filed rates of Company's wholesale supplier of natural gas, plus

(b) Other gas purchases for system supply, minus

(c) Portion of such purchase cost expected to be used for non-Gas Department purposes, minus

(d) Portion of such purchase cost expected to be injected into underground storage, plus

(e) Expected underground storage withdrawals at the average unit cost of working gas contained therein.

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous quarter's expected gas cost and the actual cost of gas during that quarter.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 12 of this Tariff.

Company shall file a revised Gas Supply Cost Component (GSCC) every 3 months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. Such filing shall be made at least 30 days prior to the beginning of each 3-month period and shall include the following information:

(1) A copy of the tariff rate of Company's wholesale gas supplier applicable to such 3-month period.

(2) A statement, through the most recent 3-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

(3) A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such 3-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each 3-month period.

In the event that the Company receives from its supplier a refund of amounts paid to such supplier with respect to a prior period, the Company will make adjustments in the amounts charged to its customers under this provision, as follows:

(1) The "Refundable Amount" shall be the amount received by the Company as a refund less any portion thereof applicable to gas purchased for electric energy production. Such refundable amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the 12-month period which commences with implementation of the next gas supply clause filing, thus determining a "Refund Factor."

(2) Effective with the implementation of the next Gas Supply Clause filing, the Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be

applicable during the subsequent 12-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the refundable amount.

(3) In the event of any large or unusual refunds, the Company may apply to the Public Service Commission for the right to depart from the refund procedure herein set forth.

GENERAL RULES

Charges for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Customers under General Gas Rate G-1 may request and be granted a temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of Adjustment
for
Group Life Insurance

	Amount	Insurance Coverage		Rate	Month	Total Amount
Union Employees:						
A. For first $5,000 of Coverage						
2,459 employees X $5,000	$12,295,000	100%	$12,295,000	.59/1000	12	$ 87,048
B. For additional coverage						
Wages & Salaries	74,634,771	125	93,293,464			
Increase in Salaries - 4%	2,985,390	125	3,731,738			
			97,025,202			
LESS: First $5,000			12,295,200			
			$84,730,002	.44/1000	12	447,372
Union Subtotal						$534,420
Nonunion Employees:						
A. For first $5,000 of Coverage						
1,242 employees X $5,000	6,210,000	100	6,210,000	.59/1000	12	43,968
B. For additional coverage						
Wages & Salaries	39,545,720	125	49,432,150			
Increase in Salaries	275,825	125	344,781			
			$49,776,931			
LESS: First $5,000			6,210,000			
			$43,566,931	.44/1000	12	230,028
Nonunion Subtotal						$273,996
TOTAL						$808,416
Operating Portion @ 72%						582,060
LESS: Test Year Amount per Books						473,680
NET ADJUSTMENT						$108,380

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Federal and State Unemployment for
Test Year Ended August 31, 1987

	Federal Unemployment	State Unemployment
Total Employees as of 9/6/87	3,920	3,920
Base Wage	$ 7,000	$ 8,000
Wages Subject to Tax	$27,440,000	$31,360,000
Rate/KIUC Information Request No. 2	.8%	1.2%
Tax	$ 219,520	$ 376,320
Operating Percentage	72%	72%
	$ 158,054	$ 270,950
Operating Tax for Test Year Ended 8/31/87		
January-December 1986	149,039	298,447
January-August 1986	<145,554>	<291,919>
January-August 1987	145,655	242,849
TEST YEAR UNEMPLOYMENT	$ 149,140	$ 249,377
ADJUSTMENT	$ 8,914	$ 21,573
Electric - 77%	6,864	16,611
Gas - 23%	2,050	4,962
	$ 8,914	$ 21,573

APPENDIX D
APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Year-End Volumes of Business
Expense Adjustment

Total Expenses	$255,400,862 [1]
Wages & Salaries:	
Test Year Actual	<66,332,568>[2]
	$189,068,294
Total Electric Operations Revenues	$476,397,820 [3]
Sales to Other Utilities	<1,877,587>[4]
	$474,520,233

Ratio = $\frac{\$189,068,294}{474,520,233}$ = 39.84%

Revenue Increase Per Adjustment	$ 3,627,565
	.3984
	$ 1,445,222
Net Adjustment:	
Revenues	$ 3,627,565
Expenses	4,445,222
	$ 2,182,343

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1 Hart Exhibit 6, page 3, lines 1-6; August 31, 1987 Monthly Report, page 19.

2 Response to the Commission Order dated November 12, 1987, Item No. 16(d), page 2.

3 Hart Prepared Testimony, Exhibit 1, Column 5.

4 *Ibid*.

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. 177

Responding Witness: William Steven Seelye

Q-177. With regard to Mr. Seelye's KU direct testimony, page 46, lines 14 through 17:

a. please provide a specific reference to where the FERC predominance methodology is discussed later in this testimony (Note if this discussion was inadvertently omitted, please explain and discuss the FERC predominance methodology in this response.); and,

b. please provide reference to FERC cases, rules, and/or procedures discussing and utilizing the "FERC predominance methodology."

A-177. a. Under the FERC predominance methodology, production operation and maintenance accounts that are predominantly fixed, i.e. expenses that the FERC has determined to be predominantly incurred independently of kilowatt hour levels of output are classified as demand-related. Production operation and maintenance accounts that are predominantly variable, i.e., expenses that the FERC has determined to vary predominantly with output (kWh) are considered to be energy related. In the cost of service study, demand-related accounts are functionally assigned using the PROFIX vector and energy-related accounts are functionally assigned using the PROVAR vector.

b. The predominance methodology has been accepted in FERC proceedings for over 25 years and is a standard methodology for classifying production operation and maintenance expenses. For example, see *Public Service Company of New Mexico* (1980) 10 FERC ¶ 63,020, *Illinois Power Company* (1980), 11 FERC ¶ 63,040, *Delmarva Power & Light Company* (1981) 17 FERC ¶ 63,044, and *Ohio Edison Company* (1983) 24 FERC ¶ 63,068.

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. 178

Responding Witness: William Steven Seelye

Q-178. Please provide a copy of the most recent KU electric cost of service study filed with FERC.

A-178. See attached.

TABLE 1

PAGE 1- 1

ORDER 298 CWIP
PHASE 1

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
DEVELOPMENT OF RATE BASE									
1 ELECTRIC PLANT IN SERVICE	SUMA			1,231,422,503	1,046,831,322	184,591,181	59,828,319	28,992,500	88,620,819
2 LESS PROV FOR DEPRECIATION	SUMB			336,539,197	286,928,802	49,610,395	16,073,346	7,811,334	23,884,680
3 NET ELECTRIC PLANT	SUMC			894,883,306	759,902,520	134,980,786	43,754,973	21,181,166	64,936,139
ADDITIONS TO NET PLANT									
4 CWIP POLLUTION CONTROL	SUMD			21,728,748	17,532,033	4,196,715	1,368,071	635,648	2,003,719
5 CWIP ORDER 298	SUMD1			92,595,303	74,843,064	17,752,239	5,766,765	2,690,347	8,472,112
6 WORKING CAPITAL	SUME			90,886,489	73,999,335	16,887,155	5,421,440	2,564,184	7,985,624
DEDUCTIONS FROM NET PLANT									
7 ACCUM DEF INCOME TAX	SUMG			107,500,401	92,680,379	14,820,022	4,791,592	2,361,564	7,153,156
8 INVESTMENT TAX CREDIT	SUMG1			64,854,180	54,197,082	10,657,098	3,461,869	1,650,539	5,112,408
9 RATE BASE	SUMH			927,739,265	779,399,491	148,339,775	48,077,788	23,059,243	71,137,031
DEVELOPMENT OF REVENUE REQUIRED TO PRODUCE THE CLAIMED RATE OF RETURN									
10 RETURN (11.23% X RATE BASE)	SUMS			104,185,119	87,526,563	16,658,557	5,399,136	2,589,553	7,988,689
OPERATING EXPENSES									
11 OPERATION & MAINT EXP	SUMJ			275,643,120	229,987,436	45,655,682	15,090,726	7,195,398	22,286,123
12 DEPRECIATION & AMORT EXP	SUMK			42,486,230	35,915,724	6,570,506	2,134,127	1,018,342	3,152,469
13 TAXES OTHER THAN INC TAXES	SUML			6,972,005	6,105,620	866,385	280,863	137,417	418,280
14 INCOME TAXES	SUMT			39,800,537	33,533,178	6,267,360	2,028,826	976,313	3,005,140
15 DEFERRED INC TAX	SUMN			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
16 INVEST TAX CREDIT ADJ	SUMO			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
17 TOTAL OPERATING EXPENSES	SUMU			386,579,308	323,675,784	62,903,524	20,685,504	9,876,718	30,562,222
18 COST OF SERVICE	SUMW			490,764,428	411,202,347	79,562,081	26,084,640	12,466,271	38,550,911
19 LESS :OTHER OPER. REVENUE	SUMX			1,963,542	1,796,005	167,537	65,819	22,874	88,693
20 OPPORTUNITY SALES	SUMY			5,765,358	4,674,475	1,090,883	358,929	168,879	527,808
21 PARIS REVENUES	SUMY1			804,210	653,715	150,495	49,767	23,573	73,340
22 SALES REVENUE REQ.	SUMZ			482,231,318	404,078,152	78,153,166	25,610,126	12,250,944	37,861,070

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

	OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINIUN (F)	JACKSON PURCHASE (G)
DEVELOPMENT OF RATE BASE					
1 ELECTRIC PLANT IN SERVICE	SUMA			64,184,318	31,586,043
2 LESS PROV FOR DEPRECIATION	SUMB			17,240,045	8,485,670
3 NET ELECTRIC PLANT	SUMC			46,944,273	23,100,374
ADDITIONS TO NET PLANT					
4 CWIP POLLUTION CONTROL	SUMD			1,470,582	722,415
5 CWIP ORDER 298	SUMD1			6,219,444	3,055,683
6 WORKING CAPITAL	SUME			6,144,544	2,756,987
DEDUCTIONS FROM NET PLANT					
7 ACCUM DEF INCOME TAX	SUMG			5,137,343	2,529,522
8 INVESTMENT TAX CREDIT	SUMG1			3,716,865	1,827,825
9 RATE BASE	SUMH			51,924,633	25,278,111
DEVELOPMENT OF REVENUE REQUIRED TO PRODUCE THE CLAIMED RATE OF RETURN					
10 RETURN (11.23% X RATE BASE)	SUMS			5,831,136	2,838,732
OPERATING EXPENSES					
11 OPERATION & MAINT EXP	SUMJ			15,447,799	7,921,760
12 DEPRECIATION & AMORT EXP	SUMK			2,291,108	1,126,929
13 TAXES OTHER THAN INC TAXES	SUML			299,881	148,223
14 INCOME TAXES	SUMI			2,197,857	1,064,363
15 DEFERRED INC TAX	SUMN			608,083	299,049
16 INVEST TAX CREDIT ADJ	SUMO			627,607	308,642
17 TOTAL OPERATING EXPENSES	SUMU			21,472,335	10,868,967
18 COST OF SERVICE	SUMW			27,303,471	13,707,699
19 LESS :OTHER OPER. REVENUE	SUMX			52,871	25,974
20 OPPORTUNITY SALES	SUMY			374,401	188,674
21 PARIS REVENUES	SUMY1			51,059	26,096
22 SALES REVENUE REQ.	SUMZ			26,825,140	13,466,955

Attachment to Response to Question No. 178
Page 2 of 79
Seelye

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1	RATE BASE	SUMNA			927.739.265	779.399.491	148.339.775	48.077.788	23.059.243	71.137.031
	DEVELOPMENT OF RETURN AT PRESENT RATES									
	OPERATING REVENUES									
2	SALES REVENUES	SUMNB			463.585.602	389.691.141	73.894.461	23.963.992	11.432.344	35.396.336
3	OTHER REVENUES	SUMNC			7.728.900	6.470.479	1.258.421	424.747	191.753	616.500
4	PARIS REVENUES	SUMNC1			787.786	640.365	147.421	48.750	23.092	71.842
5	TOTAL OPERATING REVENUES	SUMND			472.102.288	396.801.985	75.300.303	24.437.490	11.647.189	36.084.679
	OPERATING EXPENSES									
6	O&M.DEPREC.OTHER TAXES	SUMNE			325.101.355	272.008.782	53.092.573	17.505.716	8.351.157	25.856.873
7	DEFERRED INC TX & ITC ADJ	SUMNF			21.677.416	18.133.825	3.543.591	1.150.962	549.247	1.700.209
8	INCOME TAXES	SUMNG			30.611.300	26.442.439	4.168.860	1.217.770	572.998	1.790.767
9	TOTAL EXPENSES	SUMNH			377.390.071	316.585.046	60.805.025	19.874.447	9.473.402	29.347.849
10	RETURN	SUMNI			94.712.217	80.216.939	14.495.278	4.563.042	2.173.787	6.736.829
11	RATE OF RETURN	SUMNJ			10.21	10.29	9.77	9.49	9.43	9.47
	DEVELOPMENT OF RETURN AT PROPOSED RATES									
	OPERATING REVENUES									
12	SALES REVENUES	SUMNB			471.440.128	389.691.141	81.748.987	27.289.128	12.921.051	40.210.179
13	OTHER REVENUES	SUMNC			7.728.900	6.470.479	1.258.421	424.747	191.753	616.500
14	PARIS REVENUES	SUMNC1	PARISC	E10	804.210	653.715	150.495	49.767	23.573	73.340
15	TOTAL OPERATING REVENUES	SUMND			479.973.238	396.815.336	83.157.902	27.763.642	13.136.377	40.900.019
	OPERATING EXPENSES									
16	O&M.DEPREC.OTHER TAXES	SUMNE			325.101.355	272.008.782	53.092.573	17.505.716	8.351.157	25.856.873
17	DEFERRED INC TX & ITC ADJ	SUMNF			21.677.416	18.133.825	3.543.591	1.150.962	549.247	1.700.209
18	INCOME TAXES	SUMNG			34.486.955	26.449.013	8.037.942	2.855.567	1.306.274	4.161.841
19	TOTAL EXPENSES	SUMNH			381.265.726	316.591.620	64.674.107	21.512.245	10.206.678	31.718.923
20	RETURN	SUMNI			98.707.512	80.223.716	18.483.796	6.251.397	2.929.699	9.181.096
21	RATE OF RETURN	SUMNJ			10.64	10.29	12.46	13.00	12.71	12.91

ORDER 298 CWIP
PHASE 1

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

	OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
1 RATE BASE	SUMNA			51,924,633	25,278,111
DEVELOPMENT OF RETURN AT PRESENT RATES					
OPERATING REVENUES					
2 SALES REVENUES	SUMNB			25,357,633	13,140,492
3 OTHER REVENUES	SUMNC			427,272	214,648
4 PARIS REVENUES	SUMNC1			50,016	25,563
5 TOTAL OPERATING REVENUES	SUMND			25,834,921	13,380,703
OPERATING EXPENSES					
6 O&M,DEPREC,OTHER TAXES	SUMNE			18,038,785	9,196,913
7 DEFERRED INC TX & ITC ADJ	SUMNF			1,235,690	607,691
8 INCOME TAXES	SUMNG			1,474,743	903,350
9 TOTAL EXPENSES	SUMNH			20,749,221	10,707,954
10 RETURN	SUMNI			5,085,700	2,672,749
11 RATE OF RETURN	SUMNJ			9.79	10.57
DEVELOPMENT OF RETURN AT PROPOSED RATES					
OPERATING REVENUES					
12 SALES REVENUES	SUMNB			28,398,316	13,140,492
13 OTHER REVENUES	SUMNC			427,272	214,648
14 PARIS REVENUES	SUMNC1	PARISC E10		51,059	26,096
15 TOTAL OPERATING REVENUES	SUMND			28,876,647	13,381,236
OPERATING EXPENSES					
16 O&M,DEPREC,OTHER TAXES	SUMNE			18,038,788	9,196,913
17 DEFERRED INC TX & ITC ADJ	SUMNF			1,235,690	607,691
18 INCOME TAXES	SUMNG			2,972,469	903,613
19 TOTAL EXPENSES	SUMNH			22,246,967	10,708,217
20 RETURN	SUMNI			6,629,680	2,673,019
21 RATE OF RETURN	SUMNJ			12.77	10.57

TABLE 3

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — TRANSMISSION (C)	MUNICIPALS PRIMARY (D)	TOTAL (E)
DEVELOPMENT OF RATE BASE									
1 ELECTRIC PLANT IN SERVICE	SUMA			1.231.422.503	1.046.831.322	184.591.161	59.828.319	28.992.500	88.820.819
2 LESS PROV FOR DEPRECIATION	SUMB			336.539.197	286.928.802	49.610.395	16.073.346	7.811.334	23.884.680
3 NET ELECTRIC PLANT	SUMC			894.883.306	759.902.520	134.980.786	43.754.973	21.181.166	64.936.139
ADDITIONS TO NET PLANT									
4 CWIP POLLUTION CONTROL	SUMD			21.728.748	17.532.033	4.196.715	1.368.071	635.648	2.003.719
5 CWIP ORDER 298	SUMD1			92.595.303	74.843.064	17.752.239	5.786.765	2.690.347	8.477.112
6 WORKING CAPITAL	SUME			90.886.489	73.999.335	16.887.155	5.421.440	2.564.164	7.985.624
DEDUCTIONS FROM NET PLANT									
7 ACCUM DEF INCOME TAX	SUMG			107.500.401	92.680.379	14.820.022	4.791.592	2.361.564	7.153.156
8 INVESTMENT TAX CREDIT	SUMGI			64.854.180	54.197.082	10.657.098	3.461.869	1.650.539	5.112.408
9 RATE BASE	SUMH			927.739.265	779.399.491	148.339.775	48.077.788	23.059.243	71.137.031
DEVELOPMENT OF RETURN									
10 OPERATING REVENUES	SUMI			472.102.288	396.801.985	75.300.303	24.437.490	11.647.169	36.084.679
OPERATING EXPENSES									
11 OPERATION & MAINT EXP	SUMJ			275.643.120	229.987.438	45.655.682	15.090.726	7.195.396	22.286.123
12 DEPRECIATION & AMORT EXP	SUMK			42.486.230	35.915.724	6.570.506	2.134.127	1.018.342	3.152.469
13 TAXES OTHER THAN INC TAXES	SUML			6.972.005	6.105.620	866.385	280.863	137.417	418.280
14 INCOME TAXES	SUMM			30.611.300	26.442.439	4.168.860	1.217.770	572.998	1.790.767
15 DEFERRED INC TAX	SUMN			10.799.249	9.054.769	1.744.480	566.399	270.949	837.347
16 INVEST TAX CREDIT ADJ	SUMO			10.878.167	9.079.056	1.799.111	584.563	278.299	862.862
17 TOTAL OPERATING EXPENSES	SUMP			377.390.071	316.585.046	60.805.025	19.674.447	9.473.402	29.347.849
18 RETURN	SUMQ			94.712.217	80.216.939	14.495.278	4.563.042	2.173.787	6.736.829
19 RATE OF RETURN	SUMR			10.21	10.29	9.77	9.49	9.43	9.47

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	DEVELOPMENT OF RATE BASE					
1	ELECTRIC PLANT IN SERVICE	SUMA			64,184,318	31,586,043
2	LESS PROV FOR DEPRECIATION	SUMB			17,240,045	8,485,670
3	NET ELECTRIC PLANT	SUMC			46,944,273	23,100,374
	ADDITIONS TO NET PLANT					
4	CWIP POLLUTION CONTROL	SUMD			1,470,582	722,415
5	CWIP ORDER 298	SUMD1			6,219,444	3,055,683
6	WORKING CAPITAL	SUME			6,144,544	2,756,987
	DEDUCTIONS FROM NET PLANT					
7	ACCUM DEF INCOME TAX	SUMG			5,137,343	2,529,522
8	INVESTMENT TAX CREDIT	SUMG1			3,716,865	1,827,825
9	RATE BASE	SUMH			51,924,633	25,278,111
	DEVELOPMENT OF RETURN					
10	OPERATING REVENUES	SUMI			25,834,921	13,380,703
	OPERATING EXPENSES					
11	OPERATION & MAINT EXP	SUMJ			15,447,799	7,921,760
12	DEPRECIATION & AMORT EXP	SUMK			2,291,108	1,126,929
13	TAXES OTHER THAN INC TAXES	SUML			299,881	148,223
14	INCOME TAXES	SUMM			1,474,743	903,350
15	DEFERRED INC TAX	SUMN			608,063	299,049
16	INVEST TAX CREDIT ADJ	SUMO			627,607	308,642
17	TOTAL OPERATING EXPENSES	SUMP			20,749,221	10,707,954
18	RETURN	SUMQ			5,085,700	2,672,749
19	RATE OF RETURN	SUMR			9.79	10.57

TABLE 4

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

ORDER 298 C-IP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	ELECTRIC PLANT IN SERVICE									
	INTANGIBLE PLANT									
1	301 ORGANIZATION	P301	Q301	PTDG	39,117	33,253	5,864	1,901	921	2,822
2	302 FRANCHISE	P302	Q302	RETAIL	56,734	56,734	0	0	0	0
3	TOTAL ACCT 301-3	P013			95,851	89,987	5,864	1,901	921	2,822
4	PRODUCTION PLANT	P10	Q10	D10	722,931,701	583,303,643	139,627,858	45,516,749	21,148,490	66,665,239
5	TRANSMISSION PLANT	P20	Q20	D10	211,461,847	170,619,863	40,841,984	13,313,921	6,186,060	19,499,981
	DISTRIBUTION PLANT									
	360-362 SUBSTATIONS									
6	DISTRIBUTION	P612D	Q612D	RETAIL	36,670,051	36,670,051	0	0	0	0
7	DIRECT ASSIGNMENT	DA612			1,233,294	0	1,233,294	67,202	1,166,092	1,233,294
8	TOTAL ACCTS 360 THRU 362	P612			37,903,345	36,670,051	1,233,294	67,202	1,166,092	1,233,294
	368 TRANSFORMERS									
9	POWER POOL	P68C	Q68C	D10	2,220,060	1,791,275	428,785	139,778	64,945	204,723
10	ALL OTHER	P68T	Q68T	RETAIL	64,387,192	64,387,192	0	0	0	0
11	TOTAL ACCT 368	P368			66,607,252	66,178,467	428,785	139,778	64,945	204,723
12	370 METERS	P370	Q370	CA370	27,756,382	27,509,983	246,399	73,168	64,758	137,926
13	ALL OTHER DISTRIBUTION	P373	Q73	RETAIL	141,267,381	141,267,381	0	0	0	0
14	TOTAL DISTRIBUTION PLANT	P30			273,534,360	271,625,882	1,908,478	280,148	1,295,795	1,575,943
15	GENERAL PLANT	P40	Q40	LABOR	23,398,744	21,191,747	2,206,997	715,601	361,234	1,076,835
16	TOTAL PLANT IN SERVICE	P00			1,231,422,503	1,046,831,322	184,591,181	59,828,319	28,992,500	88,820,819
	ACCUMULATED PROVISION FOR DEPRECIATION									
17	PRODUCTION	PAPDP	QAPDP	P10	198,636,274	160,271,436	38,364,838	12,506,406	5,810,863	16,317,269
18	TRANSMISSION	PAPDT	QAPDT	P20	51,105,982	41,235,314	9,870,668	3,217,701	1,495,044	4,712,745
	DISTRIBUTION									
19	SUBSTATIONS	PAPDDS	QAPDDS	P612	10,806,891	10,455,258	351,633	19,160	332,473	351,633
20	LINE TRANSFORMERS	PAPDDT	QAPDDT	P368	18,990,988	18,868,733	122,255	39,853	18,517	58,370
21	METERS	PAPDDM	QAPDDM	CA370	7,913,604	7,843,353	70,251	20,861	18,463	39,324
22	ALL OTHER	PAPDDO	QAPDDO	P373	40,277,779	40,277,779	0	0	0	0
23	TOTAL DISTRIBUTION	PAPDD			77,989,262	77,445,124	544,138	79,875	369,453	449,327
24	GENERAL	PAPDG	QAPDG	P40	8,807,679	7,976,928	830,751	269,364	135,975	405,339
25	TOT PROV FOR DEPRECIATION	PAPD			336,539,197	286,928,802	49,610,395	16,073,346	7,811,334	23,884,680
26	NET ELECTRIC PLANT	NIP00			894,883,306	759,902,520	134,980,786	43,754,973	21,181,166	64,936,139

TABLE 4

PAGE 4- 2

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
	ELECTRIC PLANT IN SERVICE					
	INTANGIBLE PLANT					
1	301 ORGANIZATION	P301	Q301	PTDG	2,039	1,003
2	302 FRANCHISE	P302	Q302	RETAIL	0	0
3	TOTAL ACCT 301-3	P013			2,039	1,003
4	PRODUCTION PLANT	P10	Q10	D10	48,927,347	24,035,272
5	TRANSMISSION PLANT	P20	Q20	D10	14,311,542	7,030,461
	DISTRIBUTION PLANT					
	360-362 SUBSTATIONS					
6	DISTRIBUTION	P612D	Q612D	RETAIL	0	0
7	DIRECT ASSIGNMENT	DA612			0	0
8	TOTAL ACCTS 360 THRU 362	P612			0	0
	368 TRANSFORMERS					
9	POWER POOL	P68C	Q68C	D10	150,252	73,810
10	ALL OTHER	P68T	Q68T	RETAIL	0	0
11	TOTAL ACCT 368	P368			150,252	73,810
12	370 METERS	P370	Q370	CA370	40,188	68,286
13	ALL OTHER DISTRIBUTION	P373	Q73	RETAIL	0	0
14	TOTAL DISTRIBUTION PLANT	P30			190,439	142,096
15	GENERAL PLANT	P40	Q40	LABOR	752,951	377,211
16	TOTAL PLANT IN SERVICE	P00			64,184,318	31,586,043
	ACCUMULATED PROVISION FOR DEPRECIATION					
17	PRODUCTION	PAPDP	QAPDP	P10	13,443,519	6,604,050
18	TRANSMISSION	PAPDT	QAPDT	P20	3,458,805	1,699,118
	DISTRIBUTION					
19	SUBSTATIONS	PAPDDS	QAPDDS	P612	0	0
20	LINE TRANSFORMERS	PAPDDT	QAPDDT	P368	42,840	21,045
21	METERS	PAPDDM	QAPDDM	CA370	11,458	19,469
22	ALL OTHER	PAPDDO	QAPDDO	P373	0	0
23	TOTAL DISTRIBUTION	PAPDD			54,297	40,514
24	GENERAL	PAPDG	QAPDG	P40	283,424	141,988
25	TOT PROV FOR DEPRECIATION	PAPD			17,240,045	8,485,670
26	NET ELECTRIC PLANT	NTP00			46,944,273	23,100,374

TABLE 5

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	ADDITIONS TO NET PLANT									
1	CWIP-POLLUTION CNTRL	PCWIP	QCWIP	P10	21,728,748	17,532,033	4,196,715	1,368,071	635,648	2,003,719
	CWIP ORDER 298									
2	PRODUCTION	P298P	Q298P	P10	77,392,421	62,444,760	14,947,661	4,872,731	2,264,021	7,136,752
3	TRANSMISSION	P298T	Q298T	P20	13,869,911	11,191,060	2,678,851	873,268	405,747	1,279,016
4	GENERAL	P298G	Q298G	P40	1,332,971	1,207,244	125,727	40,766	20,579	61,345
5	TOTAL ORDER 298	P298			92,595,303	74,843,064	17,752,239	5,786,765	2,690,347	8,477,112
	WORKING CAPITAL									
	MATERIALS & SUPPLIES									
6	FUEL STOCK	WFUEL	MFUEL	E10	67,176,113	54,606,832	12,571,281	4,157,160	1,969,143	6,126,303
	PLANT M & S									
7	TRANSMISSION	WMST	MST	P20	2,131,858	1,720,109	411,749	134,225	62,365	196,590
8	DISTRIBUTION	WMSD	MSD	P30	4,619,026	4,586,799	32,227	4,731	21,881	26,612
9	STORES UNDISTRIBUTED	WMSUD	MSUD	PTD	1,324,337	1,124,383	199,954	64,807	31,389	96,197
10	SUB-TOT PLT M & S	TPLMS			8,075,221	7,431,290	643,931	203,763	115,636	319,398
11	TOTAL M &S	TOTMS			75,253,334	62,038,122	13,215,212	4,360,923	2,084,778	6,445,701
	PREPAYMENTS									
12	INSURANCE	PPREPI	QPREPI	P00	248,657	211,383	37,274	12,081	5,854	17,935
13	PSC TAX	PPREPT	QPREPT	RETAIL	207,301	207,301	0	0	0	0
14	TOTAL PREPAYMENTS	PPREP			455,958	418,684	37,274	12,081	5,854	17,935
	WORKING CASH									
15	O & M WORKING CASH REQ	WCASHO			9,005,286	8,065,546	939,737	310,585	153,470	464,055
16	PLUS:FUEL REQUIREMENT	WCASHF			5,876,148	3,538,983	2,337,165	649,951	284,287	934,238
17	PURCHASED POWER REQ	WCASHP			295,764	-62,003	357,767	87,900	35,795	123,694
18	TOTAL WORKING CASH	WCASH			15,177,197	11,542,528	3,634,669	1,048,436	473,552	1,521,987
19	TOTAL WORKING CAPITAL	TOTWCP			90,886,489	73,999,335	16,887,155	5,421,440	2,564,184	7,985,624
20	TOTAL ADDITIONS TO NET PLT	TOTADD			205,210,540	166,374,431	38,836,109	12,576,276	5,890,180	18,466,455

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 OWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	DEDUCTIONS FROM NET PLANT									
	ACCUMULATED DEFERRED INC TAX									
1	PRODUCTION	PADITP	QADITP	P10	53,595,182	43,243,747	10,351,435	3,374,424	1,567,862	4,942,287
2	TRANSMISSION	PADITT	QADITT	P20	21,624,831	17,448,186	4,176,645	1,361,528	632,608	1,994,137
3	DISTRIBUTION	PADITD	QADITD	P30	31,516,531	31,296,637	219,894	32,279	149,301	181,580
4	GENERAL	PADITG	QADITG	P40	763,857	691,809	72,048	23,361	11,793	35,154
5	TOT DEFERRED INC TAX	PADIT			107,500,401	92,680,379	14,820,022	4,791,592	2,361,564	7,153,156
	INVESTMENT TAX CREDIT									
6	PRODUCTION	INVTCP	QINVP	P10	46,553,452	37,562,065	8,991,367	2,931,068	1,361,865	4,292,933
7	TRANSMISSION	INVTCT	QINVT	P20	7,929,083	6,397,651	1,531,432	499,226	231,956	731,181
8	DISTRIBUTION	INVTCD	QINVD	P30	9,662,784	9,595,366	67,418	9,896	45,775	55,671
9	GENERAL	INVTCG	QINVG	P40	708,861	642,000	66,861	21,679	10,944	32,623
10	TOTAL INVESTMENT TAX CREDI	INVTC			64,854,180	54,197,082	10,657,098	3,461,869	1,650,539	5,112,408
11	TOT DED FROM NET PLANT	TOTDED			172,354,581	146,877,461	25,477,120	8,253,461	4,012,103	12,265,564
12	RATE BASE	RB			927,739,265	779,399,491	148,339,775	46,077,788	23,059,243	71,137,031

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	FEDERAL JURISDICTION OLD DOMINION (F)	FEDERAL JURISDICTION JACKSON PURCHASE (G)
DEDUCTIONS FROM NET PLANT					
ACCUMULATED DEFERRED INC TAX					
1 PRODUCTION	PADITP	QADITP	P10	3,627,272	1,781,876
2 TRANSMISSION	PADITT	QADITT	P20	1,463,549	718,960
3 DISTRIBUTION	PADITD	QADITD	P30	21,942	16,372
4 GENERAL	PADITG	QADITG	P40	24,580	12,314
5 TOT DEFERRED INC TAX	PADIT			5,137,343	2,529,522
INVESTMENT TAX CREDIT					
6 PRODUCTION	INVTCP	QINVP	P10	3,150,694	1,547,760
7 TRANSMISSION	INVTCT	QINVT	P20	536,633	263,618
8 DISTRIBUTION	INVTCD	QINVD	P30	6,727	5,020
9 GENERAL	INVTCG	QINVG	P40	22,811	11,428
10 TOTAL INVESTMENT TAX CREDI	INVTC			3,716,865	1,827,825
11 TOT DED FROM NET PLANT	TOTDED			8,854,209	4,357,347
12 RATE BASE	RB			51,924,633	25,278,111

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	FEDERAL JURISDICTION — MUNICIPALS — PRIMARY (D)	FEDERAL JURISDICTION — MUNICIPALS — TOTAL (E)
OPERATING REVENUES									
1 SALE OF ELECTRICITY	R10			463,585,602	389,691,141	73,694,461	23,963,992	11,432,344	35,396,336
OPPORTUNITY SALES									
2 DEMAND	OPREVD	OOPRVD	D10	1,996,000	1,610,490	385,510	125,671	58,391	184,061
3 ENERGY	OPREVE	OOPRVE	E10	3,769,358	3,063,985	705,373	233,256	110,488	343,746
4 PARIS REVENUES	PARIS	OPARIS	E10	787,786	640,365	147,421	48,750	23,092	71,842
5 TOTAL OPPORTUNITY SALES	TOTOP			6,553,144	5,314,840	1,238,304	407,679	191,971	599,650
OTHER OPERATING REVENUES									
6 POLE ATTACHMENT CHARGE	PULAT	QPOLAT	P373	496,765	496,765	0	0	0	0
7 RENTS OF BUILDINGS	RNTBU	QRNTB	P00	0	0	0	0	0	0
8 RESALE FACILITY LEASE	DAFACL			16,631	0	16,631	16,631	0	16,631
9 FACILITY CHARGE	FACCH	QFACCH	RETAIL	340,040	340,040	0	0	0	0
10 TRANSMISSION LINE RENTS	TRRNT	QTRRNT	P20	41,671	33,623	8,048	2,624	1,219	3,843
11 SERVICE ON/OFF FEES	SRFEE	QSRFE	RETAIL	232,662	232,662	0	0	0	0
12 POWER CHARGES	WHEL	QWHEL	P20	723,559	583,810	139,749	45,556	21,167	66,723
13 SALES TAX COLLECTION FEES	STTAX	QSLTAX	RETAIL	91,474	91,474	0	0	0	0
14 MATERIAL SALES	MATSL	QMATSL	P00	20,740	17,631	3,109	1,008	488	1,496
15 TOTAL OTHER REVENUES	R20			1,963,542	1,796,005	167,537	65,619	22,874	88,693
16 TOTAL OPERATING REVENUES	R00			472,102,288	396,801,985	75,300,303	24,437,490	11,647,189	36,084,679

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATOR: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 296 CWIP
PHASE I

	OUT	IN	ALLOC	FEDERAL JURISDICTION OLD DOMINION (F)	FEDERAL JURISDICTION JACKSON PURCHASE (G)
OPERATING REVENUES					
1 SALE OF ELECTRICITY	R10			25,357,633	13,140,492
OPPORTUNITY SALES					
2 DEMAND	OPREVD	OOPRVD	D10	135,067	66,361
3 ENERGY	OPREVE	OOPRVE	E10	235,314	122,313
4 PARIS REVENUES	PARIS	OPARIS	E10	56,016	25,563
5 TOTAL OPPORTUNITY SALES	TOTOP			424,417	214,237
OTHER OPERATING REVENUES					
6 POLE ATTACHMENT CHARGE	POLAT	OPOLAT	P373	0	0
7 RENTS OF BUILDINGS	RNTBD	ORNTB	P00	0	0
8 RESALE FACILITY LEASE	JAFACL			0	0
9 FACILITY CHARGE	FACCH	OFACCH	RETAIL	0	0
10 TRANSMISSION LINE RENTS	TRRNT	OTRRNT	P20	2,820	1,365
11 SERVICE ON/OFF FEES	SRFEE	OSRFE	RETAIL	0	0
12 POWER CHARGES	WHEL	OWHEL	P20	46,570	24,056
13 SALES TAX COLLECTION FEES	STTAX	OSLTAX	RETAIL	0	0
14 MATERIAL SALES	MATSL	OMATSL	P00	1,061	532
15 TOTAL OTHER REVENUES	R20			52,671	25,974
16 TOTAL OPERATING REVENUES	R00			25,834,921	13,380,703

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	OPERATION AND MAINTENANCE EXPENSE									
	PRODUCTION EXPENSE-STEAM									
1	500-SUPERV & ENGINEERING	E500	X500	P10	466,769	376,617	90,152	29,386	13,655	43,043
2	501-FUEL	E501	X501	E10	163,804,650	133,151,300	30,653,350	10,136,667	4,801,485	14,936,152
3	502-507 ALL OTHER	E502	X502	P10	6,937,768	5,597,800	1,339,968	436,811	202,956	639,767
4	TOTAL STEAM OPERATIONS	E5007			171,209,187	139,125,716	32,083,471	10,602,866	5,018,096	15,620,962
5	510-SUPERV & ENGINEERING	E510	X510	E10	564,584	458,931	105,653	34,936	16,549	51,487
6	511&514 STRUCTURES & MISC.	E511	X511	P10	1,330,533	1,073,552	256,981	83,772	38,923	122,695
7	512&513 BOILER & ELEC PLANT	E512	X512	E10	10,587,120	8,605,914	1,981,206	655,159	310,332	965,492
8	TOTAL STEAM MAINTENANCE	E5104			12,482,237	10,138,398	2,343,839	773,869	365,805	1,139,674
9	TOTAL STEAM GENERATION	E5014			183,691,424	149,264,114	34,427,310	11,376,736	5,383,901	16,760,636
	PRODUCTION EXPENSE-HYDRO									
10	535-SUPERV & ENGINEERING	E535	X535	P10	2,180	1,759	421	137	64	201
11	537-540 ALL OTHER	E537	X537	P10	67,506	70,605	16,901	5,509	2,560	8,069
12	TOTAL HYDRO OPERATIONS	E5350			69,686	72,364	17,322	5,647	2,624	8,270
13	541-SUPERV & ENGINEERING	E541	X541	P10	42,653	34,415	8,238	2,685	1,248	3,933
14	542,543,&545 ALL OTHER	E542	X542	P10	176,320	142,265	34,055	11,101	5,158	16,259
15	544-ELECTRIC PLANT	E544	X544	E10	63,176	51,354	11,822	3,909	1,852	5,761
16	TOTAL HYDRO MAINTENANCE	E5355			282,149	228,034	54,115	17,696	8,258	25,954
17	TOTAL HYDRO GENERATION	E53545			371,835	300,398	71,437	23,343	10,881	34,224
	PRODUCTION EXPENSE-OTHER									
18	546-SUPERV & ENGINEERING	E546	X546	P10	32,218	25,995	6,223	2,028	942	2,971
19	547-FUEL	E547	X547	E10	22,570	18,346	4,224	1,397	662	2,058
20	548-550 ALL OTHER	E548	X548	P10	770	621	149	48	23	71
21	TOTAL OTHER OPERATIONS	E5468			55,558	44,963	10,595	3,474	1,627	5,100
22	551-SUPERV & ENGINEERING	E551	X551	P10	0	0	0	0	0	0
23	552-554 ALL OTHER	E552	X552	P10	9,271	7,480	1,791	584	271	855
24	TOTAL OTHER MAINTENANCE	E5514			9,271	7,480	1,791	584	271	855
25	TOTAL OTHER GENERATION	E54652			64,829	52,443	12,386	4,057	1,898	5,955
	555-PURCHASED POWER									
26	CAPACITY COMPONENT	E555D	X555D	D10	6,197,272	5,000,324	1,196,948	390,189	181,294	571,482
27	ENERGY COMPONENT	E555E	X555E	E10	33,576,342	27,293,081	6,283,261	2,077,793	984,199	3,061,992
28	TOTAL ACCT 555	E555			39,773,614	32,293,405	7,480,209	2,467,982	1,165,492	3,633,474
29	556-SYSTEM CNTRL & DISP	E556	X556	D10	1,045,894	843,889	202,005	65,851	30,596	96,447
30	557-OTHER EXPENSES	E557	X557	P10	7,379	5,954	1,425	465	216	680
31	TOTAL PRODUCTION EXPENSES	E101			224,954,975	182,760,203	42,194,772	13,938,433	6,592,984	20,531,418

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	——FEDERAL JURISDICTOIN—— OLD DOMINION (F)	JACKSON PURCHASE (G)
	OPERATION AND MAINTENANCE EXPENSE					
	PRODUCTION EXPENSE-STEAM					
1	500-SUPERV & ENGINEERING	E500	X500	P10	31,590	15,519
2	501-FUEL	E501	X501	E10	10,399,841	5,315,357
3	502-507 ALL OTHER	E502	X502	P10	469,542	230,660
4	TOTAL STEAM OPERATIONS	E5007			10,900,973	5,561,536
5	510-SUPERV & ENGINEERING	E510	X510	E10	35,845	18,320
6	511&514 STRUCTURES & MISC.	E511	X511	P10	90,049	44,236
7	512&513 BOILER & ELEC PLANT	E512	X512	E10	672,169	343,545
8	TOTAL STEAM MAINTENANCE	E5104			798,063	406,102
9	TOTAL STEAM GENERATION	E5014			11,699,036	5,967,638
	PRODUCTION EXPENSE-HYDRO					
10	535-SUPERV & ENGINEERING	E535	X535	P10	148	72
11	537-540 ALL OTHER	E537	X537	P10	5,922	2,909
12	TOTAL HYDRO OPERATIONS	E5350			6,070	2,982
13	541-SUPERV & ENGINEERING	E541	X541	P10	2,887	1,418
14	542,543,&545 ALL OTHER	E542	X542	P10	11,933	5,862
15	544-ELECTRIC PLANT	E544	X544	E10	4,011	2,050
16	TOTAL HYDRO MAINTENANCE	E5355			18,831	9,330
17	TOTAL HYDRO GENERATION	E53545			24,901	12,312
	PRODUCTION EXPENSE-OTHER					
18	546-SUPERV & ENGINEERING	E546	X546	P10	2,160	1,071
19	547-FUEL	E547	X547	E10	1,435	732
20	548-550 ALL OTHER	E548	X548	P10	52	26
21	TOTAL OTHER OPERATIONS	E5468			3,666	1,829
22	551-SUPERV & ENGINEERING	E551	X551	P10	0	0
23	552-554 ALL OTHER	E552	X552	P10	627	308
24	TOTAL OTHER MAINTENANCE	E5514			627	308
25	TOTAL OTHER GENERATION	E54652			4,293	2,137
	555-PURCHASED POWER					
26	CAPACITY COMPONENT	E555D	X555D	D10	419,426	206,040
27	ENERGY COMPONENT	E555E	X555E	E10	2,131,738	1,089,531
28	TOTAL ACCT 555	E555			2,551,164	1,295,571
29	556-SYSTEM CNTRL & DISP	E556	X556	D10	70,785	34,773
30	557-OTHER EXPENSES	E557	X557	P10	499	245
31	TOTAL PRODUCTION EXPENSES	E101			14,350,678	7,312,677

TABLE 8

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	TRANSMISSION EXPENSES									
1	OTHER TRANSMISSION	E560	X560	P20	3,469,901	2,799,720	670,181	218,470	101,508	319,977
2	RENTAL EXPENSE	E567	X567A	D11	1,534,847	1,328,303	206,544	103,651	48,159	151,811
3	TOTAL TRANSMISSION	E20			5,004,748	4,128,024	876,724	322,121	149,667	471,788
	DISTRIBUTION EXPENSES									
4	580-SUPERV & ENGINEERING	E560	X560	P30	849,333	843,407	5,926	870	4,023	4,893
5	582-STATION EXPENSES	E582	X582	P612	119,682	115,788	3,894	212	3,682	3,894
6	583-OVERHEAD LINES	E583	X583	RETAIL	568,214	568,214	0	0	0	0
7	584-UNDERGROUND LINES	E584	X584	RETAIL	14,433	14,433	0	0	0	0
8	585-STREET LIGHTING	E585	X585	RETAIL	410,730	410,730	0	0	0	0
9	586-METERS	E586	X586	CA370	1,749,417	1,733,887	15,530	4,612	4,082	8,693
10	587-CUSTOMER INSTALLATION	E587	X587	RETAIL	183,741	183,741	0	0	0	0
11	588-589 MISC. & RENTS	E588	X588	P30	944,684	938,093	6,591	968	4,475	5,443
12	TOTAL DIST OPERATION	E5809			4,640,234	4,808,293	31,941	6,661	16,262	22,923
13	590-SUPERV & OPERATION	E590	X590	P30	437,421	434,369	3,052	448	2,072	2,520
14	591-MAINT OF STRUCTURES	E591	X591	P612	18,148	17,558	590	32	558	590
15	592-MAINT OF STATION EQUIP	E592	X592	P612	796,139	770,234	25,905	1,412	24,493	25,905
16	593-MAINT OF OH LINES	E593	X593	RETAIL	6,421,021	6,421,021	0	0	0	0
17	594-MAINT OF UG LINES	E594	X594	RETAIL	194,008	194,008	0	0	0	0
18	595-MAINT OF LINE TRANSF	E595	X595	P366	915,710	909,815	5,895	1,922	893	2,815
19	596-MAINT OF ST LIGHTING	E596	X596	RETAIL	191,670	191,670	0	0	0	0
20	597-MAINT OF METERS	E597	X597	CA370	192,353	190,645	1,708	507	449	956
21	598-MISCELLANEOUS	E598	X598	P30	51,008	50,652	356	52	242	294
22	TOTAL DISTR MAINTENANCE	E5908			9,217,478	9,179,973	37,505	4,373	28,707	33,080
23	TOTAL DISTRIBUTION EXPENSES	E30			14,057,712	13,988,265	69,447	11,034	44,969	56,003
24	901-905 CUSTOMER ACCTS EXP.	E9015	X9015	CUSADA	8,271,268	8,259,102	12,166	3,603	3,582	7,186
25	907-916 SALES & CUST SERV.	E9116	X9116	CRTAIL	1,946,625	1,946,625	0	0	0	0

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

		OUT	IN	ALLOC	——FEDERAL JURISDICTOIN—— OLD DOMINION (F)	JACKSON PURCHASE (G)
	TRANSMISSION EXPENSES					
1	OTHER TRANSMISSION	E560	X560	P20	234,840	115,364
2	RENTAL EXPENSE	E567	X567A	D11	0	54,733
3	TOTAL TRANSMISSION	E20			234,840	170,097
	DISTRIBUTION EXPENSES					
4	580-SUPERV & ENGINEERING	E580	X580	P30	591	441
5	582-STATION EXPENSES	E582	X582	P612	0	0
6	583-OVERHEAD LINES	E583	X583	RETAIL	0	0
7	584-UNDERGROUND LINES	E584	X584	RETAIL	0	0
8	585-STREET LIGHTING	E585	X585	RETAIL	0	0
9	586-METERS	E586	X586	CA370	2,533	4,304
10	587-CUSTOMER INSTALLATION	E587	X587	RETAIL	0	0
11	588-589 MISC. & RENTS	E588	X588	P30	658	491
12	TOTAL DIST OPERATION	E5809			3,782	5,236
13	590-SUPERV & OPERATION	E590	X590	P30	305	227
14	591-MAINT OF STRUCTURES	E591	X591	P612	0	0
15	592-MAINT OF STATION EQUIP	E592	X592	P612	0	0
16	593-MAINT OF OH LINES	E593	X593	RETAIL	0	0
17	594-MAINT OF UG LINES	E594	X594	RETAIL	0	0
18	595-MAINT OF LINE TRANSF	E595	X595	P368	2,066	1,015
19	596-MAINT OF ST LIGHTING	E596	X596	RETAIL	0	0
20	597-MAINT OF METERS	E597	X597	CA370	279	473
21	598-MISCELLANEOUS	E598	X598	P30	36	26
22	TOTAL DISTR MAINTENANCE	E5908			2,684	1,742
23	TOTAL DISTRIBUTION EXPENSES	E30			6,466	6,978
24	901-905 CUSTOMER ACCTS EXP.	E9015	X9015	CUSADA	2,314	2,6[illegible]5
25	907-916 SALES & CUST SERV.	E9116	X9116	CRTAIL	0	0

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

TABLE 8

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	—FEDERAL JURISDICTOIN— OLD DOMINION (F)	JACKSON PURCHASE (G)
	ADMINISTRATIVE & GENERAL					
	NET PLANT COMPONENT					
1	924-PROPERTY INSURANCE	E924	X924	P00	48,717	23,975
2	TOTAL NET PLANT COMPONENT	E51			48,717	23,975
	LABOR COMPONENT					
3	920-922 ACCOUNTS	E920	X920	LABOR	195,527	97,955
4	923-OUTSIDE SERVICES	E923	X923	LABOR	31,154	15,607
5	925-INJURIES & DAMAGES	E925	X925	LABOR	40,540	20,310
6	926-PENSIONS & BENEFITS	E926	X926	LABOR	242,474	121,474
7	929-930 ACCOUNTS	E930	X930	LABOR	38,726	19,401
8	931-RENTS	E931	X931	LABOR	23,444	11,745
9	932-MAINTENANCE	E932	X932	LABOR	16,410	8,221
10	TOTAL LABOR COMPONENT	E53			588,275	294,712
	928-REGULATORY COMMISSION					
11	STATE JURISDICTION	E928S	X928S	RETAIL	0	0
12	FEDERAL JURISDICTION	E928F	X928F	FEDSLS	216,508	110,657
13	TOTAL ACCOUNT 928	E928			216,508	110,657
14	930-E.P.R.I. & ADVERTIZING	E927	X927	RETAIL	0	0
15	TOTAL ADMINISTRATIVE & GEN	E50			853,501	429,344
16	TOTAL OPERATION & MAINTENANCE	E00X			15,447,799	7,921,760
	DEPRC & AMORT EXPENSES					
	DEPRECIATION EXP					
17	PRODUCTION PLANT	DXP	XDP	P10	1,974,367	969,906
18	TRANSMISSION PLANT	DXT	XDT	P20	298,804	146,786
	DISTRIBUTION PLANT					
19	SUBSTATIONS	DXDS	XDDS	P612	0	0
20	LINE TRANSFORMERS	DXDT	XDDT	P368	4,360	2,142
21	METERS	DXDM	XDDM	CA370	1,088	1,849
22	ALL OTHER	DXDO	XDDO	P373	0	0
23	TOTAL DISTRIBUTION	DXD			5,448	3,991
24	GENERAL PLANT	DXG	XDG	P40	12,469	6,247
25	TOTAL DEPRC & AMORT EXP	DXDO			2,291,108	1,126,929

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
TAXES OTHER THAN INCOME TAX									
1 PROPERTY	TOTIT1	TOIT1	NTP00	4,307,133	3,657,461	649,672	210,596	101,946	312,542
2 PSC	TOTIT2	TOIT2	RETAIL	356,386	356,386	0	0	0	0
3 UNEMPLOYMENT	TOTIT3	TOIT3	LABOR	204,952	185,621	19,331	6,268	3,164	9,432
4 FICA	TOTIT4	TOIT4	LABOR	2,092,658	1,895,276	197,382	64,000	32,307	96,306
5 MISCELLANEOUS	TOTIT5	TOIT5	RETAIL	10,876	10,876	0	0	0	0
6 TOTAL OTHER TAXES	TOTX			6,972,005	6,105,620	866,385	280,863	137,417	418,280
PROV FOR DEFERRED TAXES									
7 PRODUCTION	DFTXP	QDFTXP	P10	7,640,861	6,165,096	1,475,765	481,079	223,524	704,603
8 TRANSMISSION	DFTXT	QDFTXT	P20	1,311,321	1,058,051	253,270	82,563	38,361	120,924
9 DISTRIBUTION	DFTXD	QDFTXD	P30	1,817,781	1,805,098	12,683	1,862	8,611	10,473
10 GENERAL	DFTXG	QDFTXG	P40	29,286	26,524	2,762	896	452	1,348
11 PROV FOR DEFERRED TAX	TOTDEF			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
INVESTMENT TAX CREDIT ADJ									
12 PRODUCTION	ITCP	QITCP	P10	7,586,494	6,121,230	1,465,264	477,656	221,934	699,590
13 TRANSMISSION	ITCT	QITCT	P20	1,570,857	1,267,460	303,397	98,903	45,954	144,857
14 DISTRIBUTION	ITCD	QITCD	P30	1,509,655	1,499,122	10,533	1,546	7,152	8,698
15 GENERAL	ITCG	QITCG	P40	211,161	191,244	19,917	6,458	3,260	9,718
16 INVEST TAX CREDIT ADJ	TOTITC			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
17 TOT EXP OTHER THAN INC. TAX	EXO			346,778,771	290,142,607	56,636,164	18,656,678	8,900,404	27,557,082

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
TAXES OTHER THAN INCOME TAX					
1 PROPERTY	TOTIT1	TOIT1	NTP00	225,946	111,184
2 PSC	TOTIT2	TOIT2	RETAIL	0	0
3 UNEMPLOYMENT	TOTIT3	TOIT3	LABOR	6,595	3,304
4 FICA	TOTIT4	TOIT4	LABOR	67,340	33,736
5 MISCELLANEOUS	TOTIT5	TOIT5	RETAIL	0	0
6 TOTAL OTHER TAXES	TOTX			299,881	148,223
PROV FOR DEFERRED TAXES					
7 PRODUCTION	DFTXP	QDFTXP	P10	517,126	254,035
8 TRANSMISSION	DFTXT	QDFTXT	P20	88,749	43,597
9 DISTRIBUTION	DFTXD	QDFTXD	P30	1,266	944
10 GENERAL	DFTXG	QDFTXG	P40	942	472
11 PROV FOR DEFERRED TAX	TOTDEF			608,083	299,049
INVESTMENT TAX CREDIT ADJ					
12 PRODUCTION	ITCP	QITCP	P10	513,447	252,228
13 TRANSMISSION	ITCT	QITCT	P20	106,314	52,226
14 DISTRIBUTION	ITCD	QITCD	P30	1,051	784
15 GENERAL	ITCG	QITCG	P40	6,795	3,404
16 INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
17 TOT EXP OTHER THAN INC. TAX	EXO			19,274,478	9,804,604

TABLE 10

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31. 1982

ORDER 298 CWIP
PHASE 1

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1 OPERATING INCOME BEFORE TAX	OPY			125.323.517	106.659.379	18.664.138	5.780.812	2.746.785	8.527.596
DEVELOPMENT OF FED INC TAX									
ADDITIONS TO INCOME									
2 PROV FOR DEFERRED TAX	TOTDEF			10.799.249	9.054.769	1.744.480	566.399	270.949	837.347
3 INVEST TAX CREDIT ADJ	TOTITC			10.878.167	9.079.056	1.799.111	584.563	278.299	862.862
4 TOTAL ADDITIONS	TADD			21.677.416	18.133.825	3.543.591	1.150.962	549.247	1.700.209
DEDUCTIONS FROM INCOME									
5 INTEREST (.0461 X RATE BASE)	DEDS			42.768.780	35.930.317	6.838.464	2.216.386	1.063.031	3.279.417
6 EXCESS BK DEP ON ST LN	DED11	QDED11	P00	-2.564.978	-2.180.486	-384.492	-124.619	-60.390	-185.008
7 TOTAL DEDUCTIONS	TDED			40.809.390	34.264.641	6.544.750	2.121.190	1.016.899	3.138.089
8 TAXABLE INCOME	FTNI			106.191.543	90.526.563	15.662.960	4.810.584	2.279.132	7.089.717
TOTAL FED & STATE INC TAXES									
9 INC TAX @ 49.240% EFF RATE	IT			52.288.716	44.576.264	7.712.451	2.368.732	1.122.245	3.490.976
10 CURRENT FED & STATE INC TAX	TXLB			30.611.300	26.442.439	4.168.860	1.217.770	572.998	1.790.767
11 PROV FOR DEFERRED TAX	TOTDEF			10.799.249	9.054.769	1.744.480	566.399	270.949	837.347
12 INVEST TAX CREDIT ADJ	TOTITC			10.878.167	9.079.056	1.799.111	584.563	278.299	862.862
13 RETURN	RET			94.712.217	80.216.939	14.495.278	4.563.042	2.173.787	6.736.829
14 RATE OF RETURN	RR			10.21	10.29	9.77	9.49	9.43	9.47

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	FEDERAL JURISDICTION OLD DOMINION (F)	FEDERAL JURISDICTION JACKSON PURCHASE (G)
1 OPERATING INCOME BEFORE TAX	OPY			6,560,443	3,576,099
DEVELOPMENT OF FED INC TAX					
ADDITIONS TO INCOME					
2 PROV FOR DEFERRED TAX	TOTDEF			608,083	299,049
3 INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
4 TOTAL ADDITIONS	TADD			1,235,690	607,691
DEDUCTIONS FROM INCOME					
5 INTEREST (.0461 X RATE BASE)	DED5			2,393,726	1,165,321
6 EXCESS BK DEP ON ST LN	DED11	GDED11	P00	-133,692	-65,792
7 TOTAL DEDUCTIONS	TDED			2,291,598	1,115,062
8 TAXABLE INCOME	FTNI			5,504,536	3,068,728
TOTAL FED & STATE INC TAXES					
9 INC TAX @ 49.240% EFF RATE	IT			2,710,433	1,511,042
10 CURRENT FED & STATE INC TAX	TXLB			1,474,743	903,350
11 PROV FOR DEFERRED TAX	TOTDEF			608,083	299,049
12 INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
13 RETURN	RET			5,085,700	2,672,749
14 RATE OF RETURN	RR			9.79	10.57

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
DEMAND RELATED ALLOCATION FACTORS									
1 DEMAND (AVG KW GEN LEVEL)	D10			1,871,450	1,509,996	361,454	117,829	54,747	172,576
2 DEMAND (AVG KW GEN LEVEL)	D11			1,744,792	1,509,996	234,796	117,829	54,747	172,576
ENERGY RELATED ALLOCATION FACTORS									
3 ENERGY (MWH AT GEN LEVEL)	E10			10,832,599	8,805,456	2,027,143	670,350	317,528	987,878
4 ENERGY (MWH AT GEN LEVEL	E1X			10,832,599	8,805,456	2,027,143	670,350	317,528	987,878
5 ENERGY (MWH AT CUST LEVEL)	E99			10,119,037	8,149,254	1,969,783	652,787	305,464	958,251
CUSTOMER RELATED ALLOCATION FACTORS									
6 AVERAGE CUSTOMERS	C10			341,653	341,612	41	6	12	18
OTHER ALLOCATION FACTORS									
7 DIRECT ASSIGN OF DIST SUBS	DA612			1,233,294	0	1,233,294	67,202	1,166,092	1,233,294
8 DIRECT ASSIGN OF METERS	CA370			27,750,444	27,504,098	246,346	73,152	64,744	137,896
9 DIRECT ASSIGN OF ACCTS 902-5	CUSADA			8,270,228	8,258,064	12,164	3,603	3,582	7,185
10 ALL LABOR EXPENSES	LABOR			31,578,495	28,599,974	2,978,521	965,762	487,514	1,453,276
11 PROD-TRANSM PLANTS	PT			934,393,548	753,923,706	180,469,842	58,830,670	27,334,550	86,165,220
12 PROD-TRANSM-DISTR PLANTS	PTD			1,207,927,908	1,025,549,589	182,378,319	59,110,818	28,630,345	87,741,163
13 PROD-TRANSM-DISTR-GENL PLTS	PTDG			1,231,326,652	1,046,741,335	184,585,317	59,826,419	28,991,579	88,817,998
14 DIRECT ASSIGN-FCTY LEASE REV	DAFACL			16,631	0	16,631	16,631	0	16,631
15 DIRECT ASSIGN OF TAP LINES	DAJP			1,871,450	1,509,996	361,454	117,829	54,747	172,576
16 FUEL REQUIREMENT PERCENTAGES	EFUELP			0.309639	0.026575	0.283064	0.064110	0.059200	0.123310
17 PURCHASED POWER REQ. PERC.	EPURPC			0.167176	-0.001920	0.169096	0.035616	0.030712	0.066328

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
DEMAND RELATED ALLOCATION FACTORS					
1 DEMAND (AVG KW GEN LEVEL)	D10			126,658	62,220
2 DEMAND (AVG KW GEN LEVEL)	D11			0	62,220
ENERGY RELATED ALLOCATION FACTORS					
3 ENERGY (MWH AT GEN LEVEL)	E10			687,754	351,511
4 ENERGY (MWH AT GEN LEVEL	E11			667,754	351,511
5 ENERGY (MWH AT CUST LEVEL)	E99			673,243	338,289
CUSTOMER RELATED ALLOCATION FACTORS					
6 AVERAGE CUSTOMERS	C10			1	22
OTHER ALLOCATION FACTORS					
7 DIRECT ASSIGN OF DIST SUBS	DA612			0	0
8 DIRECT ASSIGN OF METERS	CA370			40,179	68,271
9 DIRECT ASSIGN OF ACCTS 902-5	CUSADA			2,314	2,665
10 ALL LABOR EXPENSES	LABOR			1,016,169	509,076
11 PROD-TRANSM PLANTS	PT			63,238,889	31,065,733
12 PROD-TRANSM-DISTR PLANTS	PTD			63,429,326	31,207,829
13 PROD-TRANSM-DISTR-GENL PLTS	PTDG			64,182,279	31,585,040
14 DIRECT ASSIGN-FCTY LEASE REV	DAFACL			0	0
15 DIRECT ASSIGN OF TAP LINES	DAJP			126,658	62,220
16 FUEL REQUIREMENT PERCENTAGES	EFUELP			0.108877	0.050877
17 PURCHASED POWER REQ. PERC.	EPURPC			0.080384	0.022384

TABLE 11

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

DEVELOPMENT OF LABOR ALLOCATION FACTORS

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION – MUNICIPALS – TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	PRODUCTION									
1	ENERGY RELATED	L911	K911	E10	4.620.430	3.916.366	902.064	298.301	141.296	439.599
2	DEMAND RELATED	L912	K912	D10	6.866.508	5.540.303	1.326.205	432.325	200.871	633.196
3	TOTAL PRODUCTION	L910			11.486.938	9.456.668	2.228.270	730.626	342.169	1.072.795
4	TRANSMISSION	L920	K920	D10	1.044.105	842.445	201.660	65.738	30.544	96.282
5	DISTRIBUTION	L930	K930	P30	6.670.154	6.623.616	46.538	6.831	31.596	38.429
6	TOTAL PTD	LPTD			19.401.197	16.924.729	2.476.468	803.195	404.311	1.207.506
7	CUSTOMER ACCOUNTING	L9015	K9015	CUSADA	5.347.600	5.339.735	7.865	2.330	2.316	4.646
8	SALES & CUST SERV & INFO	L9116	K9116	CRTAIL	1.590.276	1.590.276	0	0	0	0
9	ADMIN. & GENERAL	L950	K950	LABORX	5.239.420	4.745.232	494.188	160.237	80.887	241.124
10	ALL LABOR EXPENSES	LABOR			31.578.495	28.599.974	2.978.521	965.762	487.514	1.453.276

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	DEVELOPMENT OF LABOR ALLOCATION FACTORS					
	PRODUCTION					
1	ENERGY RELATED	L911	K911	E10	306,046	156,420
2	DEMAND RELATED	L912	K912	D10	464,719	228,290
3	TOTAL PRODUCTION	L910			770,765	384,710
4	TRANSMISSION	L920	K920	D10	70,664	34,713
5	DISTRIBUTION	L930	K930	P30	4,644	3,465
6	TOTAL PTD	LPTD			846,072	422,889
7	CUSTOMER ACCOUNTING	L9015	K9015	CUSADA	1,496	1,723
8	SALES & CUST SERV & INFO	L9116	K9116	CRTAIL	0	0
9	ADMIN. & GENERAL	L950	K950	LABORX	168,600	84,465
10	ALL LABOR EXPENSES	LABOR			1,016,169	509,076

TABLE 12 PAGE 15- 1

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1	RATE OF RETURN	RRT			10.209	10.292	9.772	9.491	9.427	9.470
2	SALES REVENUE REQUIREMENT	REVRQ			463,585,602	389,691,141	73,894,461	23,963,992	11,432,344	35,396,336
3	PRESENT SALES REVENUE	R10P			463,585,602	389,691,141	73,894,461	23,963,992	11,432,344	35,396,336
4	REV DEF(REVRQ-R10)	REVDEF			0	0	0	0	0	0
5	PERCENT REVENUE INCREASE	RPI			-0.00	-0.00	-0.00	-0.00	-0.00	-0.00

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
1	RATE OF RETURN	RRT			9.794	10.573
2	SALES REVENUE REQUIREMENT	REVRQ			25,357,633	13,140,492
3	PRESENT SALES REVENUE	RIOP			25,357,633	13,140,492
4	REV DEF(REVRQ-RIO)	REVDEF			0	0
5	PERCENT REVENUE INCREASE	RPT			-0.00	-0.00

TABLE 12

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	DEVELOPMENT OF REVENUE REQUIREMENTS									
	CUSTOMER COMPONENT									
1	CUSTOMER COMPONENT	REVC			22,963,210	22,889,306	73,904	21,629	19,718	41,347
2	AVERAGE CUSTOMERS	C10			341,653	341,612	41	6	12	18
3	REVENUE REQ $/MO/CUST	REV1			5.60	5.58	150.21	300.41	136.93	191.42
	ENERGY COMPONENT									
4	ENERGY COMPONENT	REVE			220,696,175	178,767,003	41,929,172	13,815,184	6,536,806	20,351,990
5	ENERGY (MWH AT CUST LEVEL)	E99			10,119,037	8,149,254	1,969,783	652,787	305,464	958,251
6	REVENUE REQ IN MILLS/KWH	REV2			21.81	21.94	21.29	21.16	21.40	21.24
	CAPACITY COMPONENT									
7	CAPACITY COMPONENT	REVD			219,926,216	188,034,832	31,891,384	10,127,179	4,875,820	15,002,999
8	ANNUAL BILLING DEMAND (KW)	D99			6,033,285	1,509,551	4,523,734	1,417,932	683,222	2,101,154
9	REVENUE REQ IN $/MO/KW	REV3			36.45	124.56	7.05	7.14	7.14	7.14

TABLE 12

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	DEVELOPMENT OF REVENUE REQUIREMENTS					
	CUSTOMER COMPONENT					
1	CUSTOMER COMPONENT	REVC			12,568	19,990
2	AVERAGE CUSTOMERS	C10			1	22
3	REVENUE REQ $/MO/CUST	REV1			1047.29	75.72
	ENERGY COMPONENT					
4	ENERGY COMPONENT	REVE			14,288,824	7,288,356
5	ENERGY (MWH AT CUST LEVEL)	E99			673,243	338,289
6	REVENUE REQ IN MILLS/KWH	REV2			21.22	21.54
	CAPACITY COMPONENT					
7	CAPACITY COMPONENT	REVD			11,056,241	5,832,144
8	ANNUAL BILLING DEMAND (KW)	D99			1,577,711	844,869
9	REVENUE REQ IN $/MO/KW	REV3			7.01	6.90

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	DEVELOPMENT OF REVENUE REQUIREMENTS									
1	RATE BASE	RB			927,739,265	779,399,491	148,339,775	48,077,788	23,059,243	71,137,031
2	CUSTOMER COMPONENT	RB			22,562,149	22,405,831	156,318	46,413	41,290	87,703
3	CAPACITY COMPONENT	RB			827,329,231	695,269,755	132,059,476	42,847,496	20,590,885	63,438,381
4	COMMODITY COMPONENT	RB			77,847,886	61,723,905	16,123,981	5,183,878	2,427,068	7,610,946
5	RETURN	RTN			94,712,217	80,216,939	14,495,278	4,563,042	2,173,787	6,736,829
6	CUSTOMER COMPONENT	RTN			2,321,393	2,306,041	15,352	4,405	3,892	8,297
7	CAPACITY COMPONENT	RTN			84,462,996	71,556,183	12,904,813	4,066,637	1,941,096	6,007,733
8	COMMODITY COMPONENT	RTN			7,927,828	6,352,715	1,575,113	492,000	228,799	720,799
9	TOTAL OPERATION & MAINTENANCE	E00X			275,643,120	229,987,438	45,655,682	15,090,726	7,195,396	22,286,123
10	CUSTOMER COMPONENT	E00X			17,702,651	17,661,366	41,285	12,246	11,409	23,655
11	CAPACITY COMPONENT	E00X			45,334,888	40,024,868	5,310,021	1,750,343	870,785	2,621,127
12	COMMODITY COMPONENT	E00X			212,605,581	172,301,204	40,304,377	13,328,137	6,313,204	19,641,341
13	TOTAL DEPRC & AMORT EXP	DX00			42,486,230	35,915,724	6,570,506	2,134,127	1,018,342	3,152,469
14	CUSTOMER COMPONENT	DX00			863,492	856,617	6,875	2,041	1,811	3,852
15	CAPACITY COMPONENT	DX00			41,551,823	35,001,463	6,550,360	2,127,697	1,014,453	3,142,150
16	COMMODITY COMPONENT	DX00			70,916	57,645	13,271	4,388	2,079	6,467
17	TOTAL OTHER TAXES	TOTX			6,972,005	6,105,620	866,385	280,663	137,417	416,280
18	CUSTOMER COMPONENT	TOTX			780,060	777,965	2,095	622	573	1,195
19	CAPACITY COMPONENT	TOTX			5,758,596	4,975,400	783,196	253,425	124,142	377,567
20	COMMODITY COMPONENT	TOTX			433,349	352,255	81,094	26,817	12,702	39,519
21	TOTAL INCOME TAXES	ITX			30,611,300	26,442,439	4,168,860	1,217,770	572,998	1,790,767
22	CUSTOMER COMPONENT	ITX			889,037	883,859	5,178	1,389	1,211	2,600
23	CAPACITY COMPONENT	ITX			25,550,550	22,186,759	3,363,791	973,249	459,472	1,432,721
24	COMMODITY COMPONENT	ITX			4,171,713	3,371,822	799,891	243,132	112,314	355,446

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

		OUT	IN	ALLOC	FEDERAL JURISDICTION OLD DOMINION (F)	FEDERAL JURISDICTION JACKSON PURCHASE (G)
	DEVELOPMENT OF REVENUE REQUIREMENTS					
1	RATE BASE	RB			51,924,633	25,278,111
2	CUSTOMER COMPONENT	RB			25,672	42,943
3	CAPACITY COMPONENT	RB			46,019,429	22,601,666
4	COMMODITY COMPONENT	RB			5,879,532	2,633,502
5	RETURN	RTN			5,085,700	2,672,749
6	CUSTOMER COMPONENT	RTN			2,514	4,540
7	CAPACITY COMPONENT	RTN			4,507,322	2,389,758
8	COMMODITY COMPONENT	RTN			575,864	278,450
9	TOTAL OPERATION & MAINTENANCE	EOOX			15,447,799	7,921,760
10	CUSTOMER COMPONENT	EOOX			7,212	10,418
11	CAPACITY COMPONENT	EOOX			1,766,418	922,476
12	COMMODITY COMPONENT	EOOX			13,674,169	6,988,867
13	TOTAL DEPRC & AMORT EXP	DX00			2,291,108	1,126,929
14	CUSTOMER COMPONENT	DX00			1,124	1,899
15	CAPACITY COMPONENT	DX00			2,285,481	1,122,729
16	COMMODITY COMPONENT	DX00			4,502	2,301
17	TOTAL OTHER TAXES	TOTX			299,881	148,223
18	CUSTOMER COMPONENT	TOTX			361	540
19	CAPACITY COMPONENT	TOTX			272,007	133,622
20	COMMODITY COMPONENT	TOTX			27,513	14,062
21	TOTAL INCOME TAXES	ITX			1,474,743	903,350
22	CUSTOMER COMPONENT	ITX			845	1,733
23	CAPACITY COMPONENT	ITX			1,180,582	750,488
24	COMMODITY COMPONENT	ITX			293,316	151,129

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1	PROV FOR DEFERRED TAX	TOTDEF			10,799,249	9,054,769	1,744,460	566,399	270,949	837,347
2	CUSTOMER COMPONENT	TOTDEF			192,923	191,270	1,653	491	435	925
3	CAPACITY COMPONENT	TOTDEF			10,600,967	8,859,143	1,741,624	565,576	270,357	835,933
4	COMMODITY COMPONENT	TOTDEF			5,360	4,357	1,003	332	157	489
5	INVEST TAX CREDIT ADJ	TOTITC			10,876,167	9,079,056	1,799,111	584,563	278,299	862,862
6	CUSTOMER COMPONENT	TOTITC			214,237	212,766	1,471	437	389	825
7	CAPACITY COMPONENT	TOTITC			10,625,285	8,834,876	1,790,408	581,735	276,777	858,512
8	COMMODITY COMPONENT	TOTITC			36,646	31,414	7,232	2,391	1,133	3,524
9	COST OF SERVICE	REV			472,102,288	396,801,985	75,300,303	24,437,490	11,647,189	36,084,679
10	CUSTOMER COMPONENT	REV			22,963,792	22,889,883	73,909	21,631	19,719	41,350
11	CAPACITY COMPONENT	REV			223,885,105	191,440,691	32,444,413	10,318,662	4,957,082	15,275,744
12	COMMODITY COMPONENT	REV			225,253,391	182,471,411	42,781,981	14,097,197	6,670,388	20,767,585
13	TOTAL OPPORTUNITY SALES	TOTOP			6,553,144	5,314,840	1,238,304	407,679	191,971	599,650
14	CUSTOMER COMPONENT	TOTOP			0	0	0	0	0	0
15	CAPACITY COMPONENT	TOTOP			1,996,000	1,610,490	385,510	125,671	58,391	184,061
16	COMMODITY COMPONENT	TOTOP			4,557,144	3,704,349	852,795	282,008	133,580	415,588
17	PARIS REVENUE INCREMENT	PARINC	GPAR2	E10	0	0	0	0	0	0
18	TOTAL OTHER REVENUES	R20			1,963,542	1,796,005	167,537	65,619	22,874	88,693
19	CUSTOMER COMPONENT	R20			581	577	4	1	1	2
20	CAPACITY COMPONENT	R20			1,962,888	1,795,369	167,519	65,813	22,871	88,684
21	COMMODITY COMPONENT	R20			72	59	13	4	2	7
22	SALES REVENUE REQUIREMENT	REVRQ			463,585,602	389,691,141	73,894,461	23,963,992	11,432,344	35,396,336
23	CUSTOMER COMPONENT	REVRQ			22,963,210	22,889,306	73,904	21,629	19,718	41,347
24	CAPACITY COMPONENT	REVRQ			219,926,216	188,034,632	31,891,384	10,127,179	4,875,820	15,002,999
25	COMMODITY COMPONENT	REVRQ			220,696,175	178,767,003	41,929,172	13,815,184	6,536,806	20,351,990

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
1	PROV FOR DEFERRED TAX	TOTDEF			608,083	299,049
2	CUSTOMER COMPONENT	TOTDEF			270	456
3	CAPACITY COMPONENT	TOTDEF			607,473	298,418
4	COMMODITY COMPONENT	TOTDEF			340	174
5	INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
6	CUSTOMER COMPONENT	TOTITC			242	404
7	CAPACITY COMPONENT	TOTITC			624,912	306,984
8	COMMODITY COMPONENT	TOTITC			2,454	1,254
9	COST OF SERVICE	REV			25,834,921	13,380,703
10	CUSTOMER COMPONENT	REV			12,566	19,991
11	CAPACITY COMPONENT	REV			11,244,194	5,924,475
12	COMMODITY COMPONENT	REV			14,578,159	7,436,237
13	TOTAL OPPORTUNITY SALES	TOTOP			424,417	214,237
14	CUSTOMER COMPONENT	TOTOP			0	0
15	CAPACITY COMPONENT	TOTOP			135,087	66,361
16	COMMODITY COMPONENT	TOTOP			289,330	147,876
17	PARIS REVENUE INCREMENT	PARINC	OPAR2	E10	0	0
18	TOTAL OTHER REVENUES	R20			52,871	25,974
19	CUSTOMER COMPONENT	R20			1	1
20	CAPACITY COMPONENT	R20			52,866	25,970
21	COMMODITY COMPONENT	R20			5	2
22	SALES REVENUE REQUIREMENT	REVRQ			25,357,633	13,140,492
23	CUSTOMER COMPONENT	REVRQ			12,568	19,990
24	CAPACITY COMPONENT	REVRQ			11,056,241	5,832,144
25	COMMODITY COMPONENT	REVRQ			14,288,824	7,288,358

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1	RATE OF RETURN	RRT			11.230	11.230	11.230	11.230	11.230	11.230
2	SALES REVENUE REQUIREMENT	REVRQ			482,231,318	404,078,152	78,153,166	25,610,126	12,250,944	37,861,070
3	PRESENT SALES REVENUE	R10P			463,585,602	389,691,141	73,894,461	23,963,992	11,432,344	35,396,336
4	REV DEF(REVRQ-R10)	REVDEF			18,645,716	14,387,011	4,258,705	1,646,134	818,600	2,464,734
5	PERCENT REVENUE INCREASE	RPT			4.02	3.69	5.76	6.87	7.16	6.96

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	——FEDERAL JURISDICTOIN—— OLD DOMINION (F)	JACKSON PURCHASE (G)
1	RATE OF RETURN	RRT			11.230	11.230
2	SALES REVENUE REQUIREMENT	REVRQ			26,825,140	13,466,955
3	PRESENT SALES REVENUE	R10P			25,357,633	13,140,492
4	REV DEF(REVRQ-R10)	REVDEF			1,467,507	326,463
5	PERCENT REVENUE INCREASE	RPT			5.79	2.48

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	DEVELOPMENT OF REVENUE REQUIREMENTS									
	CUSTOMER COMPONENT									
1	CUSTOMER COMPONENT	REVC			23,381,524	23,303,281	78,243	23,219	21,185	44,404
2	AVERAGE CUSTOMERS	C10			341,653	341,612	41	6	12	18
3	REVENUE REQ $/MO/CUST	REV1			5.70	5.68	159.03	322.49	147.11	205.57
	ENERGY COMPONENT									
4	ENERGY COMPONENT	REVE			222,284,341	179,894,077	42,390,264	13,991,768	6,622,536	20,614,304
5	ENERGY (MWH AT CUST LEVEL)	E59			10,119,037	8,149,254	1,969,783	652,787	305,464	958,251
6	REVENUE REQ IN MILLS/KWH	REV2			21.97	22.07	21.52	21.43	21.68	21.51
	CAPACITY COMPONENT									
7	CAPACITY COMPONENT	REVD			236,565,452	200,880,794	35,684,658	11,595,139	5,607,224	17,202,362
8	ANNUAL BILLING DEMAND (KW)	D99			6,033,285	1,509,551	4,523,734	1,417,932	683,222	2,101,154
9	REVENUE REQ IN $/MO/KW	REV3			39.21	133.07	7.89	8.18	8.21	8.19

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	JACKSON PURCHASE (G)
	DEVELOPMENT OF REVENUE REQUIREMENTS					
	CUSTOMER COMPONENT					
1	CUSTOMER COMPONENT	REVC			13,294	20,545
2	AVERAGE CUSTOMERS	C10			1	22
3	REVENUE REQ $/MO/CUST	REV1			1107.80	77.82
	ENERGY COMPONENT					
4	ENERGY COMPONENT	REVE			14,454,068	7,321,892
5	ENERGY (MWH AT CUST LEVEL)	E99			673,243	338,289
6	REVENUE REQ IN MILLS/KWH	REV2			21.47	21.64
	CAPACITY COMPONENT					
7	CAPACITY COMPONENT	REVD			12,357,778	6,124,518
8	ANNUAL BILLING DEMAND (KW)	D99			1,577,711	844,869
9	REVENUE REQ IN $/MO/KW	REV3			7.83	7.25

TABLE 13

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
DEVELOPMENT OF REVENUE REQUIREMENTS									
1 RATE BASE	RB			927,739,265	779,399,491	148,339,775	48,077,788	23,059,243	71,137,031
2 CUSTOMER COMPONENT	RB			22,562,149	22,405,831	156,318	46,413	41,290	87,703
3 CAPACITY COMPONENT	RB			827,329,231	695,269,755	132,059,476	42,847,496	20,590,885	63,438,381
4 COMMODITY COMPONENT	RB			77,847,886	61,723,905	16,123,981	5,183,878	2,427,068	7,610,946
5 RETURN	RTN			104,185,119	87,526,563	16,658,557	5,399,136	2,589,553	7,988,689
6 CUSTOMER COMPONENT	RTN			2,533,729	2,516,175	17,555	5,212	4,637	9,849
7 CAPACITY COMPONENT	RTN			92,909,073	78,078,793	14,830,279	4,811,774	2,312,356	7,124,130
8 COMMODITY COMPONENT	RTN			8,742,318	6,931,594	1,810,723	582,150	272,560	854,709
9 TOTAL OPERATION & MAINTENANCE	E00X			275,643,120	229,987,438	45,655,682	15,090,726	7,195,396	22,286,123
10 CUSTOMER COMPONENT	E00X			17,702,651	17,661,366	41,285	12,246	11,409	23,655
11 CAPACITY COMPONENT	E00X			45,334,888	40,024,868	5,310,021	1,750,343	870,785	2,621,127
12 COMMODITY COMPONENT	E00X			212,605,581	172,301,204	40,304,377	13,328,137	6,313,204	19,641,341
13 TOTAL DEPRC & AMORT EXP	DX00			42,486,230	35,915,724	6,570,506	2,134,127	1,018,342	3,152,469
14 CUSTOMER COMPONENT	DX00			863,492	856,617	6,875	2,041	1,811	3,852
15 CAPACITY COMPONENT	DX00			41,551,823	35,001,463	6,550,360	2,127,697	1,014,453	3,142,150
16 COMMODITY COMPONENT	DX00			70,916	57,645	13,271	4,388	2,079	6,467
17 TOTAL OTHER TAXES	TOTX			6,972,005	6,105,620	866,385	280,863	137,417	418,280
18 CUSTOMER COMPONENT	TOTX			780,060	777,965	2,095	622	573	1,195
19 CAPACITY COMPONENT	TOTX			5,758,596	4,975,400	783,196	253,425	124,142	377,567
20 COMMODITY COMPONENT	TOTX			433,349	352,255	81,094	26,817	12,702	39,519
21 TOTAL INCOME TAXES	ITX			39,800,537	33,533,178	6,267,360	2,028,826	976,313	3,005,140
22 CUSTOMER COMPONENT	ITX			1,095,014	1,087,700	7,314	2,172	1,934	4,105
23 CAPACITY COMPONENT	ITX			33,743,710	28,512,110	5,231,600	1,696,073	819,615	2,515,688
24 COMMODITY COMPONENT	ITX			4,961,813	3,933,367	1,028,446	330,582	154,764	485,347

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	JACKSON PURCHASE (G)
	DEVELOPMENT OF REVENUE REQUIREMENTS					
1	RATE BASE	RB			51,924,633	25,278,111
2	CUSTOMER COMPONENT	RB			25,672	42,943
3	CAPACITY COMPONENT	RB			46,019,429	22,601,666
4	COMMODITY COMPONENT	RB			5,879,532	2,633,502
5	RETURN	RTN			5,831,136	2,838,732
6	CUSTOMER COMPONENT	RTN			2,883	4,822
7	CAPACITY COMPONENT	RTN			5,167,982	2,538,167
8	COMMODITY COMPONENT	RTN			660,271	295,742
9	TOTAL OPERATION & MAINTENANCE	EOOX			15,447,799	7,921,760
10	CUSTOMER COMPONENT	EOOX			7,212	10,418
11	CAPACITY COMPONENT	EOOX			1,766,418	922,476
12	COMMODITY COMPONENT	EOOX			13,674,169	6,988,867
13	TOTAL DEPRC & AMORT EXP	DX00			2,291,108	1,126,929
14	CUSTOMER COMPONENT	DX00			1,124	1,899
15	CAPACITY COMPONENT	DX00			2,285,481	1,122,729
16	COMMODITY COMPONENT	DX00			4,502	2,301
17	TOTAL OTHER TAXES	TOTX			299,881	148,223
18	CUSTOMER COMPONENT	TOTX			361	540
19	CAPACITY COMPONENT	TOTX			272,007	133,622
20	COMMODITY COMPONENT	TOTX			27,513	14,062
21	TOTAL INCOME TAXES	ITX			2,197,857	1,064,363
22	CUSTOMER COMPONENT	ITX			1,203	2,006
23	CAPACITY COMPONENT	ITX			1,821,459	894,453
24	COMMODITY COMPONENT	ITX			375,196	167,904

TABLE 13

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1	PROV FOR DEFERRED TAX	TOTDEF			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
2	CUSTOMER COMPONENT	TOTDEF			192,923	191,270	1,653	491	435	925
3	CAPACITY COMPONENT	TOTDEF			10,600,967	8,859,143	1,741,824	565,576	270,357	835,933
4	COMMODITY COMPONENT	TOTDEF			5,360	4,357	1,003	332	157	489
5	INVEST TAX CREDIT ADJ	TOTITC			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
6	CUSTOMER COMPONENT	TOTITC			214,237	212,766	1,471	437	389	825
7	CAPACITY COMPONENT	TOTITC			10,625,285	8,834,876	1,790,408	581,735	276,777	858,512
8	COMMODITY COMPONENT	TOTITC			38,646	31,414	7,232	2,391	1,133	3,524
9	COST OF SERVICE	REV			490,764,428	411,202,347	79,562,081	26,084,640	12,466,271	38,550,911
10	CUSTOMER COMPONENT	REV			23,382,105	23,303,858	78,247	23,221	21,166	44,406
11	CAPACITY COMPONENT	REV			240,524,341	204,286,653	36,237,688	11,766,622	5,688,485	17,475,108
12	COMMODITY COMPONENT	REV			226,857,982	183,611,836	43,246,146	14,274,797	6,756,600	21,031,397
13	TOTAL OPPORTUNITY SALES	TOTOP			6,553,144	5,314,840	1,238,304	407,679	191,971	599,650
14	CUSTOMER COMPONENT	TOTOP			0	0	0	0	0	0
15	CAPACITY COMPONENT	TOTOP			1,996,000	1,610,490	385,510	125,671	58,391	184,061
16	COMMODITY COMPONENT	TOTOP			4,557,144	3,704,349	852,795	282,008	133,580	415,588
17	PARIS REVENUE INCREMENT	PARINC	OPAR2	E10	16,424	13,351	3,073	1,016	481	1,498
18	TOTAL OTHER REVENUES	R20			1,963,542	1,796,005	167,537	65,819	22,874	88,693
19	CUSTOMER COMPONENT	R20			581	577	4	1	1	2
20	CAPACITY COMPONENT	R20			1,962,888	1,795,369	167,519	65,813	22,871	88,684
21	COMMODITY COMPONENT	R20			72	59	13	4	2	7
22	SALES REVENUE REQUIREMENT	REVRQ			482,231,318	404,078,152	78,153,166	25,610,126	12,250,944	37,861,070
23	CUSTOMER COMPONENT	REVRQ			23,381,524	23,303,281	78,243	23,219	21,185	44,404
24	CAPACITY COMPONENT	REVRQ			236,565,452	200,880,794	35,684,658	11,595,139	5,607,224	17,202,362
25	COMMODITY COMPONENT	REVRQ			222,264,341	179,894,077	42,390,264	13,991,768	6,622,536	20,614,304

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
1	PROV FOR DEFERRED TAX	TOTDEF			608,083	299,049
2	CUSTOMER COMPONENT	TOTDEF			270	458
3	CAPACITY COMPONENT	TOTDEF			607,473	298,418
4	COMMODITY COMPONENT	TOTDEF			340	174
5	INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
6	CUSTOMER COMPONENT	TOTITC			242	404
7	CAPACITY COMPONENT	TOTITC			624,912	306,984
8	COMMODITY COMPONENT	TOTITC			2,454	1,254
9	COST OF SERVICE	REV			27,303,471	13,707,699
10	CUSTOMER COMPONENT	REV			13,294	20,546
11	CAPACITY COMPONENT	REV			12,545,731	6,216,849
12	COMMODITY COMPONENT	REV			14,744,446	7,470,304
13	TOTAL OPPORTUNITY SALES	TOTOP			424,417	214,237
14	CUSTOMER COMPONENT	TOTOP			0	0
15	CAPACITY COMPONENT	TOTOP			135,087	66,361
16	COMMODITY COMPONENT	TOTOP			289,330	147,876
17	PARIS REVENUE INCREMENT	PARINC	OPAR2	E10	1,043	533
18	TOTAL OTHER REVENUES	R20			52,871	25,974
19	CUSTOMER COMPONENT	R20			1	1
20	CAPACITY COMPONENT	R20			52,866	25,970
21	COMMODITY COMPONENT	R20			5	2
22	SALES REVENUE REQUIREMENT	REVRQ			26,825,140	13,466,955
23	CUSTOMER COMPONENT	REVRQ			13,294	20,545
24	CAPACITY COMPONENT	REVRQ			12,357,778	6,124,518
25	COMMODITY COMPONENT	REVRQ			14,454,068	7,321,892

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	ELECTRIC PLANT IN SERVICE									
	ELECTRIC PLANT IN SERVICE									
1	TOTAL PLANT IN SERVICE	P00			1,231,422,503	1,046,831,322	184,591,181	59,828,319	28,992,500	88,820,819
2	PRODUCTION	P10	Q10	D10	722,931,701	583,303,843	139,627,858	45,516,749	21,146,490	66,665,239
3	TRANSMISSION	P20	Q20	D10	211,461,847	170,619,863	40,841,984	13,313,921	6,186,060	19,499,981
4	DISTRIBUTION	P30			273,534,360	271,625,882	1,908,478	280,148	1,295,795	1,575,943
5	GENERAL	P40	Q40	LABOR	23,494,595	21,281,734	2,212,861	717,502	362,155	1,079,657
6	ACCUM. PROV. FOR DEPRECIATIO	PAPD			336,539,197	286,928,802	49,610,395	16,073,346	7,811,334	23,884,680
7	PRODUCTION	PAPDP	QAPDP	P10	198,636,274	160,271,436	38,364,838	12,506,406	5,810,863	18,317,269
8	TRANSMISSION	PAPDT	QAPDT	P20	51,105,982	41,235,314	9,870,668	3,217,701	1,495,044	4,712,745
9	DISTRIBUTION	PAPDD			77,989,262	77,445,124	544,138	79,875	369,453	449,327
10	GENERAL	PAPDG	QAPDG	P40	8,807,679	7,976,928	830,751	269,364	135,975	405,339
	ADDITIONS TO NET PLANT									
11	POLLUTION CONTROL	PCWIP	QCWIP	P10	21,728,746	17,532,033	4,196,715	1,368,071	635,648	2,003,719
12	ORDER 298	P298			92,595,303	74,843,064	17,752,239	5,786,765	2,690,347	8,477,112
	WORKING CAPITAL									
	MATERIALS & SUPPLIES									
13	PROD FUEL STOCK	WFUEL	MFUEL	E10	67,178,113	54,606,832	12,571,281	4,157,160	1,969,143	6,126,303
14	TRANSMISSION	WMST	MST	P20	2,757,240	2,153,899	603,341	197,696	88,318	286,014
15	DISTRIBUTION	WMSD	MSD	P30	5,317,981	5,277,391	40,590	6,066	27,318	33,384
16	PREPAYMENTS	PPREP			455,958	418,684	37,274	12,081	5,854	17,935
17	PRODUCTION	PPAYP			145,638	117,676	27,963	9,114	4,239	13,354
18	TRANSMISSION	PPAYT			44,544	35,991	8,552	2,788	1,297	4,084
19	DISTRIBUTION	PPAYD			54,392	54,016	377	55	256	311
20	GENERAL	PPAYG			211,384	211,002	382	124	63	186
21	WORKING CASH	WCASH			15,177,197	11,542,528	3,634,669	1,048,436	473,552	1,521,987
22	PRODUCTION	WCP			9,923,559	6,515,042	3,408,517	972,070	429,928	1,401,998
23	TRANSMISSION	WCT			737,109	606,004	131,105	47,278	21,968	69,246
24	DISTRIBUTION	WCD			2,361,469	2,348,573	12,896	1,998	8,483	10,481
25	GENERAL	WCG			2,155,061	2,072,909	82,152	27,089	13,173	40,262
26	TOTAL WORKING CAPITAL	TOTWCP			90,886,489	73,999,335	16,887,155	5,421,440	2,564,184	7,985,624

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31. 1982

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
	ELECTRIC PLANT IN SERVICE					
	ELECTRIC PLANT IN SERVICE					
1	TOTAL PLANT IN SERVICE	P00			64.184.318	31.586.043
2	PRODUCTION	P10	Q10	D10	48.927.347	24.035.272
3	TRANSMISSION	P20	Q20	D10	14.311.542	7.030.461
4	DISTRIBUTION	P30			190.439	142.096
5	GENERAL	P40	Q40	LABOR	754.990	378.214
6	ACCUM. PROV. FOR DEPRECIATIO	PAPD			17.240.045	6.485.670
7	PRODUCTION	PAPDP	QAPDP	P10	13.443.519	6.604.050
8	TRANSMISSION	PAPDT	QAPDT	P20	3.458.805	1.699.118
9	DISTRIBUTION	PAPDD			54.297	40.514
10	GENERAL	PAPDG	QAPDG	P40	283.424	141.988
	ADDITIONS TO NET PLANT					
11	POLLUTION CONTROL	PCWIP	QCWIP	P10	1.470.582	722.415
12	ORDER 298	P298			6.219.444	3.055.683
	WORKING CAPITAL					
	MATERIALS & SUPPLIES					
13	PROD FUEL STOCK	WFUEL	MFUEL	E10	4.265.091	2.179.687
14	TRANSMISSION	WMST	MST	P20	212.911	104.415
15	DISTRIBUTION	WMSD	MSD	P30	4.129	3.077
16	PREPAYMENTS	PPREP			12.961	6.378
17	PRODUCTION	PPAYP			9.796	4.813
18	TRANSMISSION	PPAYT			2.996	1.472
19	DISTRIBUTION	PPAYD			38	28
20	GENERAL	PPAYG			130	65
21	WORKING CASH	WCASH			1.649.452	463.229
22	PRODUCTION	WCP			1.583.786	422.732
23	TRANSMISSION	WCT			36.894	24.965
24	DISTRIBUTION	WCD			1.229	1.186
25	GENERAL	WCG			27.544	14.345
26	TOTAL WORKING CAPITAL	TOTWCP			6.144.544	2.756.987

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	DEDUCTIONS FROM NET PLANT									
1	CUST. ADV. FOR CONST	PCAFC	QCAFC	RETAIL	0	0	0	0	0	0
	ACCUMULATED DEFERRED INC TAX									
2	PRODUCTION	PADITP	QADITP	P10	53.595.182	43.243.747	10.351.435	3.374.424	1.567.862	4.942.287
3	TRANSMISSION	PADITT	QADITT	P20	21.624.831	17.448.186	4.176.645	1.361.528	632.608	1.994.137
4	DISTRIBUTION	PADITD	QADITD	P30	31.516.531	31.296.637	219.894	32.279	149.301	181.580
5	GENERAL	PADITG	QADITG	P40	763.857	691.809	72.048	23.361	11.793	35.154
6	TOT DEFERRED INC TAX	PADIT			107.500.401	92.680.379	14.820.022	4.791.592	2.361.564	7.153.156
	INVESTMENT TAX CREDIT									
7	PRODUCTION	INVTCP	QINVP	P10	46.553.452	37.562.065	8.991.387	2.931.068	1.361.865	4.292.933
8	TRANSMISSION	INVTCT	QINVT	P20	7.929.083	6.397.651	1.531.432	499.226	231.956	731.181
9	DISTRIBUTION	INVTCD	QINVD	P30	9.662.784	9.595.366	67.418	9.896	45.775	55.671
10	GENERAL	INVTCG	QINVG	P40	708.861	642.000	66.861	21.679	10.944	32.623
11	TOTAL INVESTMENT TAX CREDI	INVTC			64.854.180	54.197.082	10.657.098	3.461.869	1.650.539	5.112.408
	RATE BASE									
12	RATE BASE	RB			927.739.265	779.399.491	148.339.775	48.077.788	23.059.243	71.137.031
13	PRODUCTION	RBP			600.515.272	483.442.938	117.072.335	38.083.997	17.710.879	55.794.876
14	TRANSMISSION	RBT			148.210.754	119.525.666	28.685.087	9.356.497	4.343.782	13.700.279
15	DISTRIBUTION	RBD			162.099.625	160.968.735	1.130.890	166.218	767.323	933.541
16	GENERAL	RBG			16.913.614	15.462.151	1.451.463	471.077	237.259	708.335

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
	DEDUCTIONS FROM NET PLANT					
1	CUST. ADV. FOR CONST	PCAFC	QCAFC	RETAIL	0	0
	ACCUMULATED DEFERRED INC TAX					
2	PRODUCTION	PADITP	QADITP	P10	3,627,272	1,781,876
3	TRANSMISSION	PADITT	QADITT	P20	1,463,549	718,960
4	DISTRIBUTION	PADITD	QADITD	P30	21,942	16,372
5	GENERAL	PADITG	QADITG	P40	24,580	12,314
6	TOT DEFERRED INC TAX	PADIT			5,137,343	2,529,522
	INVESTMENT TAX CREDIT					
7	PRODUCTION	INVTCP	QINVP	P10	3,150,694	1,547,760
8	TRANSMISSION	INVTCT	QINVT	P20	536,633	263,618
9	DISTRIBUTION	INVTCD	QINVD	P30	6,727	5,020
10	GENERAL	INVTCG	QINVG	P40	22,811	11,428
11	TOTAL INVESTMENT TAX CREDI	INVTC			3,716,865	1,827,825
	RATE BASE					
12	RATE BASE	RB			51,924,633	25,278,111
13	PRODUCTION	RBP			41,272,964	20,004,495
14	TRANSMISSION	RBT			10,044,058	4,940,751
15	DISTRIBUTION	RBD			112,866	84,482
16	GENERAL	RBG			494,744	248,384

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31. 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	FEDERAL JURISDICTION — MUNICIPALS — PRIMARY (D)	FEDERAL JURISDICTION — MUNICIPALS — TOTAL (E)
1	RETURN	RTN			104.185.119	87.526.563	16.658.557	5.399.136	2.589.553	7.988.689
2	PRODUCTION	RTNP			67.437.865	54.290.642	13.147.223	4.276.833	1.988.932	6.265.765
3	TRANSMISSION	RTNT			16.644.068	13.422.732	3.221.335	1.050.735	487.807	1.538.541
4	DISTRIBUTION	RTND			18.203.788	18.076.789	126.999	18.666	86.170	104.837
5	GENERAL	RTNG			1.899.399	1.736.400	162.999	52.902	26.644	79.546
6	TOTAL OPERATION & MAINTENANCE	EOOX			275.643.120	229.987.438	45.655.682	15.090.726	7.195.398	22.286.123
7	PRODUCTION	E101			233.614.015	189.767.549	43.846.465	14.479.801	6.846.410	21.326.211
8	TRANSMISSION	E20			5.896.869	4.848.030	1.048.839	378.226	175.741	553.967
9	DISTRIBUTION	E30			18.891.748	18.788.583	103.165	15.983	67.863	83.846
10	GENERAL	E40			17.240.488	16.583.275	657.213	216.715	105.384	322.099
11	DEPRECIATION EXPENSE	DX00			42.486.230	35.915.724	6.570.506	2.134.127	1.018.342	3.152.469
12	PRODUCTION PLANT	DXP	XDP	P10	29.172.789	23.538.323	5.634.466	1.836.758	853.415	2.690.172
13	TRANSMISSION PLANT	DXT	XDT	P20	4.415.007	3.562.287	852.720	277.975	129.156	407.130
14	DISTRIBUTION	DXD			8.510.948	8.464.175	46.773	7.544	29.790	37.334
15	GENERAL PLANT	DXG	XDG	P40	387.486	350.938	36.548	11.650	5.982	17.833
16	TAXES OTHER THAN INCOME	TOTX			6.972.005	6.105.620	866.385	280.863	137.417	418.280
17	PRODUCTION	OTP			3.549.004	2.867.242	681.762	222.615	103.669	326.284
18	TRANSMISSION	OTT			864.655	697.997	166.658	54.328	25.243	79.571
19	DISTRIBUTION	OTD			1.525.844	1.515.218	10.626	1.560	7.215	8.775
20	GENERAL	OTG			1.032.501	1.025.163	7.338	2.360	1.291	3.651
21	CURRENT INCOME TAXES	ITX			39.800.537	33.533.178	6.267.360	2.028.826	976.313	3.005.140
22	PRODUCTION	ITXP			24.452.180	19.659.581	4.792.599	1.557.186	724.536	2.281.722
23	TRANSMISSION	ITXT			6.961.963	5.613.501	1.348.462	439.937	204.181	644.118
24	DISTRIBUTION	ITXD			7.504.425	7.452.072	52.353	7.699	35.513	43.212
25	GENERAL	ITXG			881.970	808.024	73.946	24.005	12.083	36.088
26	PROV FOR DEFERRED TAX	TOTDEF			10.799.249	9.054.769	1.744.480	566.399	270.949	837.347
27	PRODUCTION	DFTXP	QDFTXP	P10	7.640.861	6.165.096	1.475.765	481.079	223.524	704.603
28	TRANSMISSION	DFTXT	QDFTXT	P20	1.311.321	1.058.051	253.270	82.563	38.361	120.924
29	DISTRIBUTION	DFTXD	QDFTXD	P30	1.817.781	1.805.098	12.683	1.862	8.611	10.473
30	GENERAL	DFTXG	QDFTXG	P40	29.286	26.524	2.762	896	452	1.348
31	INVEST TAX CREDIT ADJ	TOTITC			10.878.167	9.079.056	1.799.111	584.563	278.299	862.862
32	PRODUCTION	ITCP	QITCP	P10	7.586.494	6.121.230	1.465.264	477.656	221.934	699.590
33	TRANSMISSION	ITCT	QITCT	P20	1.570.857	1.267.460	303.397	98.903	45.954	144.857
34	DISTRIBUTION	ITCD	QITCD	P30	1.509.655	1.499.122	10.533	1.546	7.152	8.698
35	GENERAL	ITCG	QITCG	P40	211.161	191.244	19.917	6.458	3.260	9.718

TABLE 13

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
1 RETURN	RTN			5.831.136	2.838.732
2 PRODUCTION	RTNP			4.634.954	2.246.505
3 TRANSMISSION	RTNT			1.127.948	554.846
4 DISTRIBUTION	RTND			12.675	9.487
5 GENERAL	RTNG			55.560	27.893
6 TOTAL OPERATION & MAINTENANCE	E00X			15.447.799	7.921.760
7 PRODUCTION	E101			14.922.469	7.597.785
8 TRANSMISSION	E20			295.148	199.724
9 DISTRIBUTION	E30			9.831	9.488
10 GENERAL	E40			220.350	114.764
11 DEPRECIATION EXPENSE	DX00			2.291.108	1.126.929
12 PRODUCTION PLANT	DXP	XDP	P10	1.974.387	969.906
13 TRANSMISSION PLANT	DXT	XDT	P20	298.804	146.786
14 DISTRIBUTION	DXD			5.448	3.991
15 GENERAL PLANT	DXG	XDG	P40	12.469	6.247
16 TAXES OTHER THAN INCOME	TOTX			299.881	148.223
17 PRODUCTION	OTP			238.021	117.457
18 TRANSMISSION	OTT			58.399	28.688
19 DISTRIBUTION	OTD			1.060	791
20 GENERAL	OTG			2.400	1.287
21 CURRENT INCOME TAXES	ITX			2.197.857	1.064.363
22 PRODUCTION	ITXP			1.695.400	815.477
23 TRANSMISSION	ITXT			472.033	232.311
24 DISTRIBUTION	ITXD			5.225	3.916
25 GENERAL	ITXG			25.199	12.658
26 PROV FOR DEFERRED TAX	TOTDEF			608.083	299.049
27 PRODUCTION	DFTXP	QDFTXP	P10	517.126	254.035
28 TRANSMISSION	DFTXT	QDFTXT	P20	68.749	43.597
29 DISTRIBUTION	DFTXD	QDFTXD	P30	1.266	944
30 GENERAL	DFTXG	QDFTXG	P40	942	472
31 INVEST TAX CREDIT ADJ	TOTITC			627.607	308.642
32 PRODUCTION	ITCP	QITCP	P10	513.447	252.228
33 TRANSMISSION	ITCT	QITCT	P20	106.314	52.226
34 DISTRIBUTION	ITCD	QITCD	P30	1.051	784
35 GENERAL	ITCG	QITCG	P40	6.795	3.404

TABLE 13

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1	COST OF SERVICE	REV			490,764,428	411,202,347	79,562,081	26,084,640	12,466,271	38,550,911
2	PRODUCTION	COSP			373,453,208	302,409,663	71,043,544	23,331,927	10,962,419	34,294,347
3	TRANSMISSION	COST			37,664,740	30,470,059	7,194,681	2,382,666	1,106,441	3,489,108
4	DISTRIBUTION	COSD			57,964,190	57,601,058	363,131	54,860	242,314	297,174
5	GENERAL	COSG			21,682,291	20,721,567	960,724	315,186	155,096	470,283
	REVENUE CREDITS									
6	PRODUCTION OPP. SALES	TOTOP			6,553,144	5,314,840	1,238,304	407,679	191,971	59[illegible],650
7	TOTAL OTHER REVENUES	R20			1,963,542	1,796,005	167,537	65,819	22,874	88,693
6	PRODUCTION	ORP			12,176	9,824	2,352	767	356	1,123
9	TRANSMISSION	ORT			768,792	620,306	148,485	48,404	22,490	70,894
10	DISTRIBUTION	ORD			1,182,179	1,165,516	16,663	16,636	22	16,658
11	GENERAL	ORG			396	358	37	12	6	18
12	SALES REVENUE REQUIREMENT	REVRQ			482,231,318	404,078,152	78,153,166	25,610,126	12,250,944	37,861,070
13	PRODUCTION	REVP			366,871,464	297,071,649	69,799,815	22,922,465	10,769,611	33,692,076
14	CUSTOMER COMPONENT	REVP			0	0	0	0	0	0
15	CAPACITY COMPONENT	REVP			145,800,016	117,633,313	28,166,703	9,161,078	4,265,674	13,446,752
16	COMMODITY COMPONENT	REVP			221,071,447	179,438,336	41,633,111	13,741,387	6,503,937	20,245,324
17	TRANSMISSION	REVT			36,895,948	29,849,753	7,046,196	2,334,262	1,083,951	3,418,214
18	DISTRIBUTION	REVD			56,782,011	56,435,543	346,468	38,224	242,292	280,516
19	GENERAL	REVG			21,661,895	20,721,208	960,687	315,174	155,090	470,264

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	JACKSON PURCHASE (G)
1	COST OF SERVICE	REV			27,303,471	13,707,699
2	PRODUCTION	COSP			24,495,805	12,253,393
3	TRANSMISSION	COST			2,447,395	1,258,179
4	DISTRIBUTION	COSD			36,556	29,402
5	GENERAL	COSG			323,716	166,726
	REVENUE CREDITS					
6	PRODUCTION OPP. SALES	TOTOP			424,417	214,237
7	TOTAL OTHER REVENUES	R20			52,871	25,974
8	PRODUCTION	ORP			824	405
9	TRANSMISSION	ORT			52,031	25,560
10	DISTRIBUTION	ORD			3	2
11	GENERAL	ORG			13	6
12	SALES REVENUE REQUIREMENT	REVRQ			26,825,140	13,466,955
13	PRODUCTION	REVP			24,069,521	12,038,218
14	CUSTOMER COMPONENT	REVP			0	0
15	CAPACITY COMPONENT	REVP			9,872,333	4,847,618
16	COMMODITY COMPONENT	REVP			14,197,187	7,190,600
17	TRANSMISSION	REVT			2,395,364	1,232,619
18	DISTRIBUTION	REVD			36,553	29,399
19	GENERAL	REVG			323,703	166,719

PHASE 1

FULL REQUIREMENT CUSTOMERS

WITHOUT ORDER 298 CWIP

11.23 PERCENT RATE OF RETURN

TABLE 1

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31. 1982

NO ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
DEVELOPMENT OF RATE BASE									
1 ELECTRIC PLANT IN SERVICE	SUMA			1.231.422.503	1.046.831.322	184.591.181	59.828.319	28.992.500	88.820.819
2 LESS PROV FOR DEPRECIATION	SUMB			336.539.197	286.928.802	49.610.395	16.073.346	7.811.334	23.884.680
3 NET ELECTRIC PLANT	SUMC			894.883.306	759.902.520	134.980.786	43.754.973	21.181.166	64.936.139
ADDITIONS TO NET PLANT									
4 CWIP POLLUTION CONTROL	SUMD			21.728.748	17.532.033	4.196.715	1.368.071	635.648	2.003.719
5 CWIP ORDER 298	SUMD1			0	0	0	0	0	0
6 WORKING CAPITAL	SUME			90.886.489	73.999.335	16.887.155	5.421.440	2.564.184	7.985.624
DEDUCTIONS FROM NET PLANT									
7 ACCUM DEF INCOME TAX	SUMG			107.500.401	92.680.379	14.820.022	4.791.592	2.361.564	7.153.156
8 INVESTMENT TAX CREDIT	SUMG1			64.854.180	54.197.082	10.657.098	3.461.869	1.650.539	5.112.408
9 RATE BASE	SUMH			835.143.962	704.556.426	130.587.536	42.291.023	20.368.895	62.659.918
DEVELOPMENT OF REVENUE REQUIRED TO PRODUCE THE CLAIMED RATE OF RETURN									
10 RETURN (11.23% X RATE BASE)	SUMS			93.786.667	79.121.687	14.664.980	4.749.282	2.287.427	7.036.709
OPERATING EXPENSES									
11 OPERATION & MAINT EXP	SUMJ			275.643.120	229.987.438	45.655.682	15.090.726	7.195.398	22.286.123
12 DEPRECIATION & AMORT EXP	SUMK			42.486.230	35.915.724	6.570.506	2.134.127	1.018.342	3.152.469
13 TAXES OTHER THAN INC TAXES	SUML			6.972.005	6.105.620	866.385	280.863	137.417	418.280
14 INCOME TAXES	SUMT			33.854.284	28.726.932	5.127.353	1.657.214	803.546	2.460.760
15 DEFERRED INC TAX	SUMN			10.799.249	9.054.769	1.744.480	566.399	270.949	837.347
16 INVEST TAX CREDIT ADJ	SUMO			10.878.167	9.079.056	1.799.111	584.563	276.299	860.862
17 TOTAL OPERATING EXPENSES	SUMU			380.633.055	318.869.539	61.763.517	20.313.892	9.703.950	30.017.842
18 COST OF SERVICE	SUMW			474.419.722	397.991.225	76.428.497	25.063.174	11.991.377	37.054.551
19 LESS :OTHER OPER. REVENUE	SUMX			1.963.542	1.796.005	167.537	65.819	22.874	88.693
20 OPPORTUNITY SALES	SUMY			5.765.358	4.674.475	1.090.883	358.929	168.879	527.808
21 PARIS REVENUES	SUMY1			804.210	653.715	150.495	49.767	23.573	73.340
22 SALES REVENUE REQ.	SUMZ			465.886.612	390.867.030	75.019.582	24.588.660	11.776.051	36.364.710

TABLE 1

PAGE 1- 2

NO ORDER 298 CWIP
PHASE I

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

	OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
DEVELOPMENT OF RATE BASE					
1 ELECTRIC PLANT IN SERVICE	SUMA			64,184,318	31,586,043
2 LESS PROV FOR DEPRECIATION	SUMB			17,240,045	8,485,670
3 NET ELECTRIC PLANT	SUMC			46,944,273	23,100,374
ADDITIONS TO NET PLANT					
4 CWIP POLLUTION CONTROL	SUMD			1,470,562	722,415
5 CWIP ORDER 298	SUMD1			0	0
6 WORKING CAPITAL	SUME			6,144,544	2,756,967
DEDUCTIONS FROM NET PLANT					
7 ACCUM DEF INCOME TAX	SUMG			5,137,343	2,529,522
8 INVESTMENT TAX CREDIT	SUMG1			3,716,865	1,827,825
9 RATE BASE	SUMH			45,705,169	22,222,428
DEVELOPMENT OF REVENUE REQUIRED TO PRODUCE THE CLAIMED RATE OF RETURN					
10 RETURN (11.23% X RATE BASE)	SUMS			5,132,693	2,495,579
OPERATING EXPENSES					
11 OPERATION & MAINT EXP	SUMJ			15,447,799	7,921,760
12 DEPRECIATION & AMORT EXP	SUMK			2,291,108	1,126,929
13 TAXES OTHER THAN INC TAXES	SUML			299,881	148,223
14 INCOME TAXES	SUMT			1,798,459	868,134
15 DEFERRED INC TAX	SUMN			608,083	299,049
16 INVEST TAX CREDIT ADJ	SUMO			627,607	308,642
17 TOTAL OPERATING EXPENSES	SUMU			21,072,937	10,672,738
18 COST OF SERVICE	SUMW			26,205,630	13,168,317
19 LESS :OTHER OPER. REVENUE	SUMX			52,871	25,974
20 OPPORTUNITY SALES	SUMY			374,401	188,674
21 PARIS REVENUES	SUMY1			51,059	26,096
22 SALES REVENUE REQ.	SUMZ			25,727,299	12,927,573

TABLE 3

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
DEVELOPMENT OF RATE BASE									
1 ELECTRIC PLANT IN SERVICE	SUMA			1,231,422,503	1,046,631,322	184,591,181	59,828,319	28,992,500	88,820,819
2 LESS PROV FOR DEPRECIATION	SUMB			336,539,197	286,928,602	49,610,595	16,073,346	7,811,334	23,884,680
3 NET ELECTRIC PLANT	SUMC			894,883,306	759,902,520	134,980,786	43,754,973	21,181,166	64,936,139
ADDITIONS TO NET PLANT									
4 CWIP POLLUTION CONTROL	SUMD			21,728,748	17,532,033	4,196,715	1,368,071	635,648	2,003,719
5 CWIP ORDER 298	SUMD1			0	0	0	0	0	0
6 WORKING CAPITAL	SUME			90,886,489	73,999,335	16,887,155	5,421,440	2,564,184	7,985,624
DEDUCTIONS FROM NET PLANT									
7 ACCUM DEF INCOME TAX	SUMG			107,500,401	92,680,379	14,820,022	4,791,592	2,361,564	7,153,156
8 INVESTMENT TAX CREDIT	SUMG1			64,854,180	54,197,082	10,657,098	3,461,869	1,650,539	5,112,408
9 RATE BASE	SUMH			835,143,962	704,556,426	130,587,536	42,291,023	20,368,895	62,659,918
DEVELOPMENT OF RETURN									
10 OPERATING REVENUES	SUMI			472,102,288	396,801,985	75,300,303	24,437,490	11,647,189	36,084,679
OPERATING EXPENSES									
11 OPERATION & MAINT EXP	SUMJ			275,643,120	229,987,438	45,655,682	15,090,726	7,195,396	22,286,123
12 DEPRECIATION & AMORT EXP	SUMK			42,486,230	35,915,724	6,570,506	2,134,127	1,018,342	3,152,469
13 TAXES OTHER THAN INC TAXES	SUML			6,972,005	6,105,620	866,385	280,863	137,417	418,280
14 INCOME TAXES	SUMM			32,713,180	28,141,350	4,571,830	1,349,127	634,067	1,983,195
15 DEFERRED INC TAX	SUMN			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
16 INVEST TAX CREDIT ADJ	SUMO			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
17 TOTAL OPERATING EXPENSES	SUMP			379,491,951	318,283,957	61,207,994	20,005,805	9,534,472	29,540,277
18 RETURN	SUMQ			92,610,337	78,518,028	14,092,309	4,431,685	2,112,717	6,544,402
19 RATE OF RETURN	SUMR			11.09	11.14	10.79	10.48	10.37	10.44

TABLE 3

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
DEVELOPMENT OF RATE BASE					
1 ELECTRIC PLANT IN SERVICE	SUMA			64,164,318	31,586,043
2 LESS PROV FOR DEPRECIATION	SUMB			17,240,045	8,485,670
3 NET ELECTRIC PLANT	SUMC			46,944,273	23,100,374
ADDITIONS TO NET PLANT					
4 CWIP POLLUTION CONTROL	SUMD			1,470,582	722,415
5 CWIP ORDER 298	SUMD1			0	0
6 WORKING CAPITAL	SUME			6,144,544	2,756,987
DEDUCTIONS FROM NET PLANT					
7 ACCUM DEF INCOME TAX	SUMG			5,137,343	2,529,522
8 INVESTMENT TAX CREDIT	SUMG1			3,716,865	1,827,825
9 RATE BASE	SUMH			45,705,189	22,222,428
DEVELOPMENT OF RETURN					
10 OPERATING REVENUES	SUMI			25,834,921	13,380,703
OPERATING EXPENSES					
11 OPERATION & MAINT EXP	SUMJ			15,447,799	7,921,760
12 DEPRECIATION & AMORT EXP	SUMK			2,291,108	1,126,929
13 TAXES OTHER THAN INC TAXES	SUML			299,881	148,223
14 INCOME TAXES	SUMM			1,615,922	972,713
15 DEFERRED INC TAX	SUMN			608,083	299,049
16 INVEST TAX CREDIT ADJ	SUMO			627,607	308,642
17 TOTAL OPERATING EXPENSES	SUMP			20,890,400	10,777,317
18 RETURN	SUMQ			4,944,521	2,603,386
19 RATE OF RETURN	SUMR			10.82	11.72

TABLE 4

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATION: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 C&IP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	ELECTRIC PLANT IN SERVICE									
	INTANGIBLE PLANT									
1	301 ORGANIZATION	P301	Q301	PTDG	39.117	33.253	5.864	1.901	921	2.822
2	302 FRANCHISE	P302	Q302	RETAIL	56.734	56.734	0	0	0	0
3	TOTAL ACCT 301-3	P013			95.851	89.987	5.864	1.901	921	2.822
4	PRODUCTION PLANT	P10	Q10	D10	722.931.701	583.303.843	139.627.858	45.516.749	21.148.490	66.665.239
5	TRANSMISSION PLANT	P20	Q20	D10	211.461.847	170.619.863	40.841.984	13.313.921	6.186.060	19.499.981
	DISTRIBUTION PLANT									
	360-362 SUBSTATIONS									
6	DISTRIBUTION	P612D	Q612D	RETAIL	36.670.051	36.670.051	0	0	0	0
7	DIRECT ASSIGNMENT	DA612			1.233.294	0	1.233.294	67.202	1.166.092	1.233.294
8	TOTAL ACCTS 360 THRU 362	P612			37.903.345	36.670.051	1.233.294	67.202	1.166.092	1.233.294
	368 TRANSFORMERS									
9	POWER POOL	P68C	Q68C	D10	2.220.060	1.791.275	428.785	139.778	64.945	204.723
10	ALL OTHER	P68T	Q68T	RETAIL	64.387.192	64.387.192	0	0	0	0
11	TOTAL ACCT 368	P368			66.607.252	66.178.467	428.785	139.778	64.945	204.723
12	370 METERS	P370	Q370	CA370	27.756.382	27.509.983	246.399	73.168	64.758	137.926
13	ALL OTHER DISTRIBUTION	P373	Q73	RETAIL	141.267.381	141.267.381	0	0	0	0
14	TOTAL DISTRIBUTION PLANT	P30			273.534.360	271.625.882	1.908.478	280.148	1.295.795	1.575.943
15	GENERAL PLANT	P40	Q40	LABOR	23.398.744	21.191.747	2.206.997	715.601	361.234	1.076.835
16	TOTAL PLANT IN SERVICE	P00			1.231.422.503	1.046.831.322	184.591.181	59.828.319	28.992.500	88.820.819
	ACCUMULATED PROVISION FOR DEPRECIATION									
17	PRODUCTION	PAPDP	QAPDP	P10	198.636.274	160.271.436	38.364.836	12.506.406	5.810.863	18.317.269
18	TRANSMISSION	PAPDT	QAPDT	P20	51.105.982	41.235.314	9.870.668	3.217.701	1.495.044	4.712.745
	DISTRIBUTION									
19	SUBSTATIONS	PAPDDS	QAPDDS	P612	10.806.891	10.455.258	351.633	19.160	332.473	351.633
20	LINE TRANSFORMERS	PAPDDT	QAPDDT	P368	18.990.988	18.868.733	122.255	39.853	18.517	58.370
21	METERS	PAPDDM	QAPDDM	CA370	7.913.604	7.843.353	70.251	20.861	18.463	39.324
22	ALL OTHER	PAPDDO	QAPDDO	P373	40.277.779	40.277.779	0	0	0	0
23	TOTAL DISTRIBUTION	PAPDD			77.989.262	77.445.124	544.138	79.875	369.453	449.327
24	GENERAL	PAPDG	QAPDG	P40	8.807.679	7.976.928	830.751	269.364	135.975	405.339
25	TOT PROV FOR DEPRECIATION	PAPD			336.539.197	286.928.802	49.610.395	16.073.346	7.811.334	23.884.680
26	NET ELECTRIC PLANT	NP00			894.883.306	759.902.520	134.980.786	43.754.973	21.181.166	64.936.139

TABLE 4

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	ELECTRIC PLANT IN SERVICE					
	INTANGIBLE PLANT					
1	301 ORGANIZATION	P301	Q301	PTDG	2,039	1,003
2	302 FRANCHISE	P302	Q302	RETAIL	0	0
3	TOTAL ACCT 301-3	P013			2,039	1,003
4	PRODUCTION PLANT	P10	Q10	D10	48,927,347	24,035,272
5	TRANSMISSION PLANT	P20	Q20	D10	14,311,542	7,030,461
	DISTRIBUTION PLANT					
	360-362 SUBSTATIONS					
6	DISTRIBUTION	P612D	Q612D	RETAIL	0	0
7	DIRECT ASSIGNMENT	DA612			0	0
8	TOTAL ACCTS 360 THRU 362	P612			0	0
	368 TRANSFORMERS					
9	POWER POOL	P68C	Q68C	D10	150,252	73,810
10	ALL OTHER	P68T	Q68T	RETAIL	0	0
11	TOTAL ACCT 368	P368			150,252	73,810
12	370 METERS	P370	Q370	CA370	40,188	66,286
13	ALL OTHER DISTRIBUTION	P373	Q73	RETAIL	0	0
14	TOTAL DISTRIBUTION PLANT	P30			190,439	142,096
15	GENERAL PLANT	P40	Q40	LABOR	752,951	377,211
16	TOTAL PLANT IN SERVICE	P00			64,164,318	31,586,043
	ACCUMULATED PROVISION FOR DEPRECIATION					
17	PRODUCTION	PAPDP	QAPDP	P10	13,443,519	6,604,050
18	TRANSMISSION	PAPDT	QAPDT	P20	3,456,805	1,699,116
	DISTRIBUTION					
19	SUBSTATIONS	PAPDDS	QAPDDS	P612	0	0
20	LINE TRANSFORMERS	PAPDDT	QAPDDT	P368	42,840	21,045
21	METERS	PAPDDM	QAPDDM	CA370	11,458	19,469
22	ALL OTHER	PAPDDO	QAPDDJ	P373	0	0
23	TOTAL DISTRIBUTION	PAPDD			54,297	40,514
24	GENERAL	PAPDG	QAPDG	P40	283,424	141,988
25	TOT PROV FOR DEPRECIATION	PAPD			17,240,045	8,485,670
26	NET ELECTRIC PLANT	NTP00			46,944,273	23,100,374

TABLE 5

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

NO ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	ADDITIONS TO NET PLANT									
1	CWIP-POLLUTION CNTRL	PCWIP	QCWIP	P10	21,728,748	17,532,033	4,196,715	1,368,071	635,648	2,003,719
	CWIP ORDER 298									
2	PRODUCTION	P298P	Q298P	P10	0	0	0	0	0	0
3	TRANSMISSION	P298T	Q298T	P20	0	0	0	0	0	0
4	GENERAL	P298G	Q298G	P40	0	0	0	0	0	0
5	TOTAL ORDER 298	P298			0	0	0	0	0	0
	WORKING CAPITAL									
	MATERIALS & SUPPLIES									
6	FUEL STOCK	WFUEL	MFUEL	E10	67,176,113	54,606,832	12,571,281	4,157,160	1,969,143	6,126,303
	PLANT M & S									
7	TRANSMISSION	WMST	MST	P20	2,131,858	1,720,109	411,749	134,225	62,365	196,590
8	DISTRIBUTION	WMSD	MSD	P30	4,619,026	4,586,799	32,227	4,731	21,881	26,612
9	STORES UNDISTRIBUTED	WMSUD	MSUD	PTD	1,324,337	1,124,363	199,954	64,807	31,389	96,197
10	SUB-TOT PLT M & S	TPLMS			8,075,221	7,431,290	643,931	203,763	115,636	319,398
11	TOTAL M &S	TOTMS			75,253,334	62,038,122	13,215,212	4,360,923	2,084,778	6,445,701
	PREPAYMENTS									
12	INSURANCE	PPREPI	QPREPI	P00	248,657	211,383	37,274	12,081	5,854	17,935
13	PSC TAX	PPREPT	QPREPT	RETAIL	207,301	207,301	0	0	0	0
14	TOTAL PREPAYMENTS	PPREP			455,958	418,684	37,274	12,081	5,854	17,935
	WORKING CASH									
15	O & M WORKING CASH REQ	WCASHO			9,005,286	8,065,548	939,737	310,585	153,470	464,055
16	PLUS:FUEL REQUIREMENT	WCASHF			5,876,148	3,538,983	2,337,165	649,951	284,287	934,238
17	PURCHASED POWER REQ	WCASHP			295,764	-62,003	357,767	87,900	35,795	123,694
18	TOTAL WORKING CASH	WCASH			15,177,197	11,542,528	3,634,669	1,048,436	473,552	1,521,987
19	TOTAL WORKING CAPITAL	TOTWCP			90,886,489	73,999,335	16,887,155	5,421,440	2,564,184	7,985,624
20	TOTAL ADDITIONS TO NET PLT	TOTADD			112,615,237	91,531,367	21,083,870	6,789,511	3,199,832	9,989,343

TABLE 5

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	JACKSON PURCHASE (G)
	ADDITIONS TO NET PLANT					
1	CWIP-POLLUTION CNTRL	PCWIP	OCWIP	P10	1,470,582	722,415
	CWIP ORDER 298					
2	PRODUCTION	P298P	Q298P	P10	0	0
3	TRANSMISSION	P298T	Q298T	P20	0	0
4	GENERAL	P298G	Q298G	P40	0	0
5	TOTAL ORDER 298	P298			0	0
	WORKING CAPITAL					
	MATERIALS & SUPPLIES					
6	FUEL STOCK	WFUEL	MFUEL	E10	4,265,091	2,179,887
	PLANT M & S					
7	TRANSMISSION	WMST	MST	P20	144,282	70,878
8	DISTRIBUTION	WMSD	MSD	P30	3,216	2,399
9	STORES UNDISTRIBUTED	WMSUD	MSUD	PTD	69,542	34,215
10	SUB-TOT PLT M & S	TPLMS			217,040	107,493
11	TOTAL M &S	TOTMS			4,482,131	2,287,380
	PREPAYMENTS					
12	INSURANCE	PPREPI	QPREPI	P00	12,961	6,378
13	PSC TAX	PPREPT	QPREPT	RETAIL	0	0
14	TOTAL PREPAYMENTS	PPREP			12,961	6,378
	WORKING CASH					
15	O & M WORKING CASH REQ	WCASHO			311,920	163,762
16	PLUS:FUEL REQUIREMENT	WCASHF			1,132,459	270,467
17	PURCHASED POWER REQ	WCASHP			205,073	29,000
18	TOTAL WORKING CASH	WCASH			1,649,452	463,229
19	TOTAL WORKING CAPITAL	TOTWCP			6,144,544	2,756,987
20	TOTAL ADDITIONS TO NET PLT	TOTADD			7,615,125	3,479,402

TABLE 6

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION - MUNICIPALS - TRANSMISSION (C)	FEDERAL JURISDICTION - MUNICIPALS - PRIMARY (D)	FEDERAL JURISDICTION - MUNICIPALS - TOTAL (E)
DEDUCTIONS FROM NET PLANT									
ACCUMULATED DEFERRED INC TAX									
1 PRODUCTION	PADITP	QADITP	P10	53.595.182	43.243.747	10,351.435	3.374.424	1.567.862	4.942.287
2 TRANSMISSION	PADITT	QADITT	P20	21.624.831	17.448.186	4.176.645	1.361.528	632.608	1.994.137
3 DISTRIBUTION	PADITD	QADITD	P30	31.516.531	31.296.637	219.894	32.279	149.301	181.580
4 GENERAL	PADITG	QADITG	P40	763.857	691.809	72.048	23.361	11.793	35.154
5 TOT DEFERRED INC TAX	PADIT			107.500.401	92.680.379	14.820.022	4.791.592	2.361.564	7.153.156
INVESTMENT TAX CREDIT									
6 PRODUCTION	INVTCP	QINVP	P10	46.553.452	37.562.065	8.991.387	2.931.068	1.361.865	4.292.933
7 TRANSMISSION	INVTCT	QINVT	P20	7.929.083	6.397.651	1.531.432	499.226	231.956	731.181
8 DISTRIBUTION	INVTCD	QINVD	P30	9.662.784	9.595.366	67.418	9.896	45.775	55.671
9 GENERAL	INVTCG	QINVG	P40	708.861	642.000	66.861	21.679	10.944	32.623
10 TOTAL INVESTMENT TAX CREDI	INVTC			64.854.180	54.197.082	10.657.098	3.461.869	1.650.539	5.112.408
11 TOT DED FROM NET PLANT	TOTDED			172.354.581	146.877.461	25.477.120	8.253.461	4.012.103	12.265.564
12 RATE BASE	Rb			835.143.962	704.556.426	130.587.536	42.291.023	20.368.895	62.659.918

TABLE 6

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	DEDUCTIONS FROM NET PLANT					
	ACCUMULATED DEFERRED INC TAX					
1	PRODUCTION	PADITP	QADITP	P10	3,627,272	1,761,876
2	TRANSMISSION	PADITT	QADITT	P20	1,463,549	716,960
3	DISTRIBUTION	PADITD	QADITD	P30	21,942	16,372
4	GENERAL	PADITG	QADITG	P40	24,580	12,314
5	TOT DEFERRED INC TAX	PADIT			5,137,343	2,529,522
	INVESTMENT TAX CREDIT					
6	PRODUCTION	INVTCP	QINVP	P10	3,150,694	1,547,760
7	TRANSMISSION	INVTCT	QINVT	P20	536,633	263,618
8	DISTRIBUTION	INVTCD	QINVD	P30	6,727	5,020
9	GENERAL	INVTCG	QINVG	P40	22,811	11,426
10	TOTAL INVESTMENT TAX CREDI	INVTC			3,716,865	1,827,825
11	TOT DED FROM NET PLANT	TOTDED			8,854,209	4,357,347
12	RATE BASE	RB			45,705,169	22,222,428

TABLE 7

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

NO ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
OPERATING REVENUES									
1 SALE OF ELECTRICITY	R10			463,585,602	389,691,141	73,894,461	23,963,992	11,432,344	35,396,336
OPPORTUNITY SALES									
2 DEMAND	OPREVD	GOPRVD	D10	1,996,000	1,610,490	385,510	125,671	58,391	184,061
3 ENERGY	OPREVE	GOPRVE	E10	3,769,358	3,063,985	705,373	233,258	110,468	343,746
4 PARIS REVENUES	PARIS	GPARIS	E10	787,786	640,365	147,421	48,750	23,092	71,842
5 TOTAL OPPORTUNITY SALES	TOTOP			6,553,144	5,314,840	1,238,304	407,679	191,971	599,650
OTHER OPERATING REVENUES									
6 POLE ATTACHMENT CHARGE	POLAT	QPOLAT	P373	496,765	496,765	0	0	0	0
7 RENTS OF BUILDINGS	RNTBU	QRNTB	P00	0	0	0	0	0	0
8 RESALE FACILITY LEASE	DAFACL			16,631	0	16,631	16,631	0	16,631
9 FACILITY CHARGE	FACCH	QFACCH	RETAIL	340,040	340,040	0	0	0	0
10 TRANSMISSION LINE RENTS	TRRNT	QTRRNT	P20	41,671	33,623	8,048	2,624	1,219	3,843
11 SERVICE ON/OFF FEES	SRFEE	QSRFE	RETAIL	232,662	232,662	0	0	0	0
12 POWER CHARGES	WHEL	QWHEL	P20	723,559	583,810	139,749	45,556	21,167	66,723
13 SALES TAX COLLECTION FEES	STTAX	QSTTAX	RETAIL	91,474	91,474	0	0	0	0
14 MATERIAL SALES	MATSL	QMATSL	P00	20,740	17,631	3,109	1,006	488	1,496
15 TOTAL OTHER REVENUES	R20			1,963,542	1,796,005	167,537	65,819	22,674	88,693
16 TOTAL OPERATING REVENUES	R00			472,102,288	396,801,985	75,300,303	24,437,490	11,647,189	36,084,679

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1962

NO ORDER 298 CW&P
PHASE I

	OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
OPERATING REVENUES					
1 SALE OF ELECTRICITY	R10			25,357,633	13,140,492
OPPORTUNITY SALES					
2 DEMAND	OPREVD	OOPRVD	D10	135,087	66,361
3 ENERGY	OPREVE	OOPRVE	E10	239,314	122,313
4 PARIS REVENUES	PARIS	OPARIS	E10	50,016	25,563
5 TOTAL OPPORTUNITY SALES	TOTOP			424,417	214,237
OTHER OPERATING REVENUES					
6 POLE ATTACHMENT CHARGE	PULAT	OPULAT	P373	0	0
7 RENTS OF BUILDINGS	RNTBU	ORNTB	P00	0	0
8 RESALE FACILITY LEASE	DAFACL			0	0
9 FACILITY CHARGE	FALCH	OFALCH	RETAIL	0	0
10 TRANSMISSION LINE RENTS	TRRNT	OTRRNT	P20	2,620	1,385
11 SERVICE ON/OFF FEES	SRFEE	OSRFE	RETAIL	0	0
12 POWER CHARGES	WHEL	OWHEL	P20	48,970	24,056
13 SALES TAX COLLECTION FEES	STTAX	OSLTAX	RETAIL	0	0
14 MATERIAL SALES	MATSL	OMATSL	P00	1,081	532
15 TOTAL OTHER REVENUES	R20			52,871	25,974
16 TOTAL OPERATING REVENUES	R00			25,834,921	13,380,703

TABLE 8

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	FEDERAL JURISDICTION — MUNICIPALS — PRIMARY (D)	FEDERAL JURISDICTION — MUNICIPALS — TOTAL (E)
	OPERATION AND MAINTENANCE EXPENSE									
	PRODUCTION EXPENSE-STEAM									
1	500-SUPERV & ENGINEERING	E500	X500	P10	466,769	376,617	90,152	29,368	13,655	43,043
2	501-FUEL	E501	X501	E10	163,804,650	133,151,300	30,653,350	10,136,667	4,801,485	14,938,152
3	502-507 ALL OTHER	E502	X502	P10	6,937,768	5,597,800	1,339,966	436,811	202,956	639,767
4	TOTAL STEAM OPERATIONS	E5007			171,209,187	139,125,716	32,083,471	10,602,866	5,018,096	15,620,962
5	510-SUPERV & ENGINEERING	E510	X510	E10	564,584	458,931	105,653	34,938	16,549	51,487
6	511&514 STRUCTURES & MISC.	E511	X511	P10	1,330,533	1,073,552	256,981	83,772	38,923	122,695
7	512&513 BOILER & ELEC PLANT	E512	X512	E10	10,587,120	8,605,914	1,981,206	655,159	310,332	965,492
8	TOTAL STEAM MAINTENANCE	E5104			12,482,237	10,138,398	2,343,839	773,869	365,805	1,139,674
9	TOTAL STEAM GENERATION	E5014			163,691,424	149,264,114	34,427,310	11,376,736	5,383,901	16,760,636
	PRODUCTION EXPENSE-HYDRO									
10	535-SUPERV & ENGINEERING	E535	X535	P10	2,180	1,759	421	137	64	201
11	537-540 ALL OTHER	E537	X537	P10	87,506	70,605	16,901	5,509	2,560	8,069
12	TOTAL HYDRO OPERATIONS	E5350			89,686	72,364	17,322	5,647	2,624	8,270
13	541-SUPERV & ENGINEERING	E541	X541	P10	42,653	34,415	8,238	2,685	1,248	3,933
14	542,543,&545 ALL OTHER	E542	X542	P10	176,320	142,265	34,055	11,101	5,158	16,259
15	544-ELECTRIC PLANT	E544	X544	E10	63,176	51,354	11,822	3,909	1,852	5,761
16	TOTAL HYDRO MAINTENANCE	E5355			282,149	228,034	54,115	17,696	8,258	25,954
17	TOTAL HYDRO GENERATION	E53545			371,835	300,398	71,437	23,343	10,881	34,224
	PRODUCTION EXPENSE-OTHER									
18	546-SUPERV & ENGINEERING	E546	X546	P10	32,218	25,995	6,223	2,028	942	2,971
19	547-FUEL	E547	X547	E10	22,570	18,346	4,224	1,397	662	2,058
20	548-550 ALL OTHER	E548	X548	P10	770	621	149	48	23	71
21	TOTAL OTHER OPERATIONS	E5468			55,558	44,963	10,595	3,474	1,627	5,100
22	551-SUPERV & ENGINEERING	E551	X551	P10	0	0	0	0	0	0
23	552-554 ALL OTHER	E552	X552	P10	9,271	7,480	1,791	584	271	855
24	TOTAL OTHER MAINTENANCE	E5514			9,271	7,480	1,791	584	271	855
25	TOTAL OTHER GENERATION	E54652			64,829	52,443	12,386	4,057	1,898	5,955
	555-PURCHASED POWER									
26	CAPACITY COMPONENT	E555D	X555D	D10	6,197,272	5,000,324	1,196,948	390,189	181,294	571,482
27	ENERGY COMPONENT	E555E	X555E	E10	33,576,342	27,293,081	6,283,261	2,077,793	984,199	3,061,992
28	TOTAL ACCT 555	E555			39,773,614	32,293,405	7,480,209	2,467,982	1,165,492	3,633,474
29	556-SYSTEM CNTRL & DISP	E556	X556	D10	1,045,894	843,889	202,005	65,851	30,596	96,447
30	557-OTHER EXPENSES	E557	X557	P10	7,379	5,954	1,425	465	216	680
31	TOTAL PRODUCTION EXPENSES	E101			224,954,975	182,760,203	42,194,772	13,938,433	6,592,964	20,531,418

TABLE 8

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	OPERATION AND MAINTENANCE EXPENSE					
	PRODUCTION EXPENSE-STEAM					
1	500-SUPERV & ENGINEERING	E500	X500	P10	31,590	15,519
2	501-FUEL	E501	X501	E10	10,399,841	5,315,357
3	502-507 ALL OTHER	E502	X502	P10	469,542	230,660
4	TOTAL STEAM OPERATIONS	E5007			10,900,973	5,561,536
5	510-SUPERV & ENGINEERING	E510	X510	E10	35,845	18,320
6	511&514 STRUCTURES & MISC.	E511	X511	P10	90,049	44,236
7	512&513 BOILER & ELEC PLANT	E512	X512	E10	672,169	343,545
8	TOTAL STEAM MAINTENANCE	E5104			798,063	406,102
9	TOTAL STEAM GENERATION	E5014			11,695,036	5,967,638
	PRODUCTION EXPENSE-HYDRO					
10	535-SUPERV & ENGINEERING	E535	X535	P10	148	72
11	537-540 ALL OTHER	E537	X537	P10	5,922	2,909
12	TOTAL HYDRO OPERATIONS	E5350			6,070	2,982
13	541-SUPERV & ENGINEERING	E541	X541	P10	2,887	1,418
14	542,543,&545 ALL OTHER	E542	X542	P10	11,933	5,862
15	544-ELECTRIC PLANT	E544	X544	E10	4,011	2,050
16	TOTAL HYDRO MAINTENANCE	E5355			18,831	9,330
17	TOTAL HYDRO GENERATION	E53545			24,901	12,312
	PRODUCTION EXPENSE-OTHER					
18	546-SUPERV & ENGINEERING	E546	X546	P10	2,180	1,071
19	547-FUEL	E547	X547	E10	1,433	732
20	548-550 ALL OTHER	E548	X548	P10	52	26
21	TOTAL OTHER OPERATIONS	E5468			3,666	1,829
22	551-SUPERV & ENGINEERING	E551	X551	P10	0	0
23	552-554 ALL OTHER	E552	X552	P10	627	308
24	TOTAL OTHER MAINTENANCE	E5514			627	308
25	TOTAL OTHER GENERATION	E54652			4,293	2,137
	555-PURCHASED POWER					
26	CAPACITY COMPONENT	E555D	X555D	D10	419,426	206,040
27	ENERGY COMPONENT	E555E	X555E	E10	2,131,738	1,089,531
28	TOTAL ACCT 555	E555			2,551,164	1,295,571
29	556-SYSTEM CNTRL & DISP	E556	X556	D10	70,785	34,773
30	557-OTHER EXPENSES	E557	X557	P10	499	245
31	TOTAL PRODUCTION EXPENSES	E101			14,350,678	7,312,677

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATION: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	TRANSMISSION EXPENSES									
1	OTHER TRANSMISSION	E560	X560	P20	3,469,901	2,799,720	670,181	218,470	101,506	319,977
2	RENTAL EXPENSE	E567	X567A	DII	1,534,847	1,328,303	206,544	103,651	48,159	151,811
3	TOTAL TRANSMISSION	E20			5,004,748	4,128,024	876,724	322,121	149,667	471,788
	DISTRIBUTION EXPENSES									
4	580-SUPERV & ENGINEERING	E580	X580	P30	849,333	843,407	5,926	870	4,023	4,893
5	582-STATION EXPENSES	E582	X582	P612	119,682	115,788	3,894	212	3,682	3,894
6	583-OVERHEAD LINES	E583	X583	RETAIL	568,214	568,214	0	0	0	0
7	584-UNDERGROUND LINES	E584	X584	RETAIL	14,433	14,433	0	0	0	0
8	585-STREET LIGHTING	E585	X585	RETAIL	410,730	410,730	0	0	0	0
9	586-METERS	E586	X586	CA370	1,749,417	1,733,887	15,530	4,612	4,082	6,693
10	587-CUSTOMER INSTALLATION	E587	X587	RETAIL	163,741	163,741	0	0	0	0
11	588-589 MISC. & RENTS	E588	X588	P30	944,684	938,093	6,591	968	4,475	5,443
12	TOTAL DIST OPERATION	E5809			4,840,234	4,808,293	31,941	6,661	16,262	22,923
13	590-SUPERV & OPERATION	E590	X590	P30	437,421	434,369	3,052	448	2,072	2,520
14	591-MAINT OF STRUCTURES	E591	X591	P612	18,148	17,558	590	32	558	590
15	592-MAINT OF STATION EQUIP	E592	X592	P612	796,139	770,234	25,905	1,412	24,493	25,905
16	593-MAINT OF OH LINES	E593	X593	RETAIL	6,421,021	6,421,021	0	0	0	0
17	594-MAINT OF UG LINES	E594	X594	RETAIL	194,008	194,008	0	0	0	0
18	595-MAINT OF LINE TRANSF	E595	X595	P366	915,710	909,815	5,895	1,922	893	2,815
19	596-MAINT OF ST LIGHTING	E596	X596	RETAIL	191,670	191,670	0	0	0	0
20	597-MAINT OF METERS	E597	X597	CA370	192,353	190,645	1,708	507	449	956
21	598-MISCELLANEOUS	E598	X598	P30	51,008	50,652	356	52	242	294
22	TOTAL DISTR MAINTENANCE	E5908			9,217,478	9,179,973	37,505	4,373	28,707	33,080
23	TOTAL DISTRIBUTION EXPENSES	E30			14,057,712	13,988,265	69,447	11,034	44,969	56,003
24	901-905 CUSTOMER ACCTS EXP.	E9015	X9015	CUSADA	8,271,268	8,259,102	12,166	3,603	3,582	7,186
25	907-916 SALES & CUST SERV.	E9116	X9116	CRTAIL	1,946,625	1,946,625	0	0	0	0

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	TRANSMISSION EXPENSES					
1	OTHER TRANSMISSION	E560	X560	P20	234,840	115,364
2	RENTAL EXPENSE	E567	X567A	D11	0	54,733
3	TOTAL TRANSMISSION	E20			234,840	170,097
	DISTRIBUTION EXPENSES					
4	580-SUPERV & ENGINEERING	E580	X580	P30	591	441
5	582-STATION EXPENSES	E582	X582	P612	0	0
6	583-OVERHEAD LINES	E583	X583	RETAIL	0	0
7	584-UNDERGROUND LINES	E584	X584	RETAIL	0	0
8	585-STREET LIGHTING	E585	X585	RETAIL	0	0
9	586-METERS	E586	X586	CA370	2,533	4,304
10	587-CUSTOMER INSTALLATION	E587	X587	RETAIL	0	0
11	588-589 MISC. & RENTS	E588	X588	P30	658	491
12	TOTAL DIST OPERATION	E5809			3,782	5,236
13	590-SUPERV & OPERATION	E590	X590	P30	305	227
14	591-MAINT OF STRUCTURES	E591	X591	P612	0	0
15	592-MAINT OF STATION EQUIP	E592	X592	P612	0	0
16	593-MAINT OF OH LINES	E593	X593	RETAIL	0	0
17	594-MAINT OF UG LINES	E594	X594	RETAIL	0	0
18	595-MAINT OF LINE TRANSF	E595	X595	P368	2,066	1,015
19	596-MAINT OF ST LIGHTING	E596	X596	RETAIL	0	0
20	597-MAINT OF METERS	E597	X597	CA370	279	473
21	598-MISCELLANEOUS	E598	X598	P30	36	26
22	TOTAL DISTR MAINTENANCE	E5908			2,684	1,742
23	TOTAL DISTRIBUTION EXPENSES	E30			6,466	6,978
24	901-905 CUSTOMER ACCTS EXP.	E9015	X9015	CUSADA	2,314	2,665
25	907-916 SALES & CUST SERV.	E9116	X9116	CRTAIL	0	0

TABLE 8

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	ADMINISTRATIVE & GENERAL									
	NET PLANT COMPONENT									
1	924-PROPERTY INSURANCE	E924	X924	P00	934,679	794,570	140,109	45,411	22,006	67,417
2	TOTAL NET PLANT COMPONENT	E51			934,679	794,570	140,109	45,411	22,006	67,417
	LABOR COMPONENT									
3	920-922 ACCOUNTS	E920	X920	LABOR	6,076,212	5,503,096	573,116	185,828	93,806	279,634
4	923-OUTSIDE SERVICES	E923	X923	LABOR	968,130	876,815	91,315	29,608	14,946	44,554
5	925-INJURIES & DAMAGES	E925	X925	LABOR	1,259,824	1,140,996	118,828	38,529	19,449	57,978
6	926-PENSIONS & BENEFITS	E926	X926	LABOR	7,535,137	6,824,414	710,723	230,446	116,329	346,775
7	929-930 ACCOUNTS	E930	X930	LABOR	1,203,465	1,089,953	113,512	36,805	18,579	55,385
8	931-RENTS	E931	X931	LABOR	728,545	659,828	68,717	22,281	11,247	33,528
9	932-MAINTENANCE	E932	X932	LABOR	509,951	461,852	48,099	15,596	7,873	23,468
10	TOTAL LABOR COMPONENT	E53			18,281,264	16,556,953	1,724,311	559,094	282,229	841,323
	928-REGULATORY COMMISSION									
11	STATE JURISDICTION	E928S	X928S	RETAIL	90,212	90,212	0	0	0	0
12	FEDERAL JURISDICTION	E928F	X928F	FEDSLS	638,154	0	638,154	211,029	99,959	310,989
13	TOTAL ACCOUNT 928	E928			728,366	90,212	638,154	211,029	99,959	310,989
14	930-E.P.R.I. & ADVERTIZING	E927	X927	RETAIL	1,463,483	1,463,483	0	0	0	0
15	TOTAL ADMINISTRATIVE & GEN	E50			21,407,792	18,905,218	2,502,574	815,534	404,195	1,219,729
16	TOTAL OPERATION & MAINTENANCE	E00X			275,643,120	229,987,438	45,655,682	15,090,726	7,195,398	22,286,123
	DEPRC & AMORT EXPENSES									
	DEPRECIATION EXP									
17	PRODUCTION PLANT	DXP	XDP	P10	29,172,789	23,538,323	5,634,466	1,836,758	853,415	2,690,172
18	TRANSMISSION PLANT	DXT	XDT	P20	4,415,007	3,562,287	852,720	277,975	129,156	407,130
	DISTRIBUTION PLANT									
19	SUBSTATIONS	DXDS	XDDS	P612	850,060	822,401	27,659	1,507	26,152	27,659
20	LINE TRANSFORMERS	DXDT	XDDT	P368	1,932,803	1,920,361	12,442	4,056	1,885	5,941
21	METERS	DXDM	XDDM	CA370	751,468	744,797	6,671	1,981	1,753	3,734
22	ALL OTHER	DXDO	XDDO	P373	4,976,617	4,976,617	0	0	0	0
23	TOTAL DISTRIBUTION	DXD			8,510,948	8,464,175	46,773	7,544	29,790	37,334
24	GENERAL PLANT	DXG	XDG	P40	387,486	350,938	36,548	11,850	5,982	17,833
25	TOTAL DEPRC & AMORT EXP	DX00			42,486,230	35,915,724	6,570,506	2,134,127	1,018,342	3,152,469

TABLE 8

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE 1

		OUT	IN	ALLOC	---FEDERAL JURISDICTOIN--- OLD DOMINION (F)	JACKSON PURCHASE (G)
	ADMINISTRATIVE & GENERAL					
	NET PLANT COMPONENT					
1	924-PROPERTY INSURANCE	E924	X924	P00	48,717	23,975
2	TOTAL NET PLANT COMPONENT	E51			48,717	23,975
	LABOR COMPONENT					
3	920-922 ACCOUNTS	E920	X920	LABOR	195,527	97,955
4	923-OUTSIDE SERVICES	E923	X923	LABOR	31,154	15,607
5	925-INJURIES & DAMAGES	E925	X925	LABOR	40,540	20,310
6	926-PENSIONS & BENEFITS	E926	X926	LABOR	242,474	121,474
7	929-930 ACCOUNTS	E930	X930	LABOR	38,726	19,401
8	931-RENTS	E931	X931	LABOR	23,444	11,745
9	932-MAINTENANCE	E932	X932	LABOR	16,410	8,221
10	TOTAL LABOR COMPONENT	E53			588,275	294,712
	928-REGULATORY COMMISSION					
11	STATE JURISDICTION	E928S	X928S	RETAIL	0	0
12	FEDERAL JURISDICTION	E928F	X928F	FEDSLS	216,508	110,657
13	TOTAL ACCOUNT 928	E928			216,508	110,657
14	930-E.P.R.I. & ADVERTIZING	E927	X927	RETAIL	0	0
15	TOTAL ADMINISTRATIVE & GEN	E50			853,501	429,344
16	TOTAL OPERATION & MAINTENANCE	EOJX			15,447,799	7,921,760
	DEPRC & AMORT EXPENSES					
	DEPRECIATION EXP					
17	PRODUCTION PLANT	DXP	XDP	P10	1,974,387	969,906
18	TRANSMISSION PLANT	DXT	XDT	P20	298,804	146,786
	DISTRIBUTION PLANT					
19	SUBSTATIONS	DXDS	XDDS	PE12	0	0
20	LINE TRANSFORMERS	DXDT	XDDT	P368	4,360	2,142
21	METERS	DXDM	XDDM	CA370	1,088	1,849
22	ALL OTHER	DXDO	XDDO	P373	0	0
23	TOTAL DISTRIBUTION	DXD			5,448	3,991
24	GENERAL PLANT	DXG	XDG	P40	12,469	6,247
25	TOTAL DEPRC & AMORT EXP	DX00			2,291,108	1,126,929

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

TABLE 9

NO ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
TAXES OTHER THAN INCOME TAX									
1 PROPERTY	TOTIT1	TOIT1	NTP00	4,307,133	3,657,461	649,672	210,596	101,946	312,542
2 PSC	TOTIT2	TOIT2	RETAIL	356,386	356,386	0	0	0	0
3 UNEMPLOYMENT	TOTIT3	TOIT3	LABOR	204,952	185,621	19,331	6,268	3,164	9,432
4 FICA	TOTIT4	TOIT4	LABOR	2,092,658	1,895,276	197,382	64,000	32,307	96,306
5 MISCELLANEOUS	TOTIT5	TOIT5	RETAIL	10,876	10,876	0	0	0	0
6 TOTAL OTHER TAXES	TOTX			6,972,005	6,105,620	666,385	280,863	137,417	418,280
PROV FOR DEFERRED TAXES									
7 PRODUCTION	DFTXP	QDFTXP	P10	7,640,861	6,165,096	1,475,765	481,079	223,524	704,603
8 TRANSMISSION	DFTXT	QDFTXT	P20	1,311,321	1,058,051	253,270	82,563	38,361	120,924
9 DISTRIBUTION	DFTXD	QDFTXD	P30	1,817,781	1,805,098	12,683	1,862	8,611	10,473
10 GENERAL	DFTXG	QDFTXG	P40	29,286	26,524	2,762	896	452	1,348
11 PROV FOR DEFERRED TAX	TOTDEF			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
INVESTMENT TAX CREDIT ADJ									
12 PRODUCTION	ITCP	QITCP	P10	7,566,494	6,121,230	1,465,264	477,656	221,934	699,590
13 TRANSMISSION	ITCT	QITCT	P20	1,570,857	1,267,460	303,397	98,903	45,954	144,857
14 DISTRIBUTION	ITCD	QITCD	P30	1,509,655	1,499,122	10,533	1,546	7,152	8,698
15 GENERAL	ITCG	QITCG	P40	211,161	191,244	19,917	6,458	3,260	9,718
16 INVEST TAX CREDIT ADJ	TOTITC			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
17 TOT EXP OTHER THAN INC. TAX	EXO			346,778,771	290,142,607	56,636,164	18,656,676	6,900,404	27,557,082

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

TABLE 9

NO ORDER 298 CWIP
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		OUT	IN	ALLOC	FEDERAL JURISDICTION OLD DOMINION (F)	FEDERAL JURISDICTION JACKSON PURCHASE (G)
	TAXES OTHER THAN INCOME TAX					
1	PROPERTY	TOTIT1	TOIT1	NTP00	225,946	111,184
2	PSC	TOTIT2	TOIT2	RETAIL	0	0
3	UNEMPLOYMENT	TOTIT3	TOIT3	LABOR	6,595	3,304
4	FICA	TOTIT4	TOIT4	LABOR	67,340	33,736
5	MISCELLANEOUS	TOTIT5	TOIT5	RETAIL	0	0
6	TOTAL OTHER TAXES	TOTX			299,881	148,223
	PROV FOR DEFERRED TAXES					
7	PRODUCTION	DFTXP	QDFTXP	P10	517,126	254,035
8	TRANSMISSION	DFTXT	QDFTXT	P20	88,749	43,597
9	DISTRIBUTION	DFTXD	QDFTXD	P30	1,266	944
10	GENERAL	DFTXG	QDFTXG	P40	942	472
11	PROV FOR DEFERRED TAX	TOTDEF			608,083	299,049
	INVESTMENT TAX CREDIT ADJ					
12	PRODUCTION	ITCP	QITCP	P10	513,447	252,228
13	TRANSMISSION	ITCT	QITCT	P20	106,314	52,226
14	DISTRIBUTION	ITCD	QITCD	P30	1,051	784
15	GENERAL	ITCG	QITCG	P40	6,795	3,404
16	INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
17	TOT EXP OTHER THAN INC. TAX	EXO			19,274,478	9,804,604

Attachment to Response to Question No. 178

Seelye

TABLE 10

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

	OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
1 OPERATING INCOME BEFORE TAX	OPY			125,323,517	106,659,379	18,664,138	5,780,812	2,746,785	6,527,596
DEVELOPMENT OF FED INC TAX									
ADDITIONS TO INCOME									
2 PROV FOR DEFERRED TAX	TOTDEF			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
3 INVEST TAX CREDIT ADJ	TOTITC			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
4 TOTAL ADDITIONS	TADD			21,677,416	18,133,825	3,543,591	1,150,962	549,247	1,700,209
DEDUCTIONS FROM INCOME									
5 INTEREST (.0461 X RATE BASE)	DED5			38,500,137	32,480,051	6,020,085	1,949,616	939,006	2,888,622
6 EXCESS BK DEP ON ST LN	DED11	ODED11	P00	-2,564,978	-2,180,486	-384,492	-124,619	-60,390	-185,006
7 TOTAL DEDUCTIONS	TDED			36,540,747	30,814,375	5,726,371	1,854,420	892,874	2,747,294
8 TAXABLE INCOME	FTNI			110,460,186	93,978,828	16,481,356	5,077,354	2,403,157	7,480,511
TOTAL FED & STATE INC TAXES									
9 INC TAX @ 49.240% EFF RATE	IT			54,390,596	46,275,175	8,115,421	2,500,089	1,183,315	3,683,404
10 CURRENT FED & STATE INC TAX	TXCB			32,713,180	28,141,350	4,571,830	1,349,127	634,067	1,983,195
11 PROV FOR DEFERRED TAX	TOTDEF			10,799,249	9,054,769	1,744,480	566,399	270,949	837,347
12 INVEST TAX CREDIT ADJ	TOTITC			10,878,167	9,079,056	1,799,111	584,563	278,299	862,862
13 RETURN	RET			92,610,337	78,518,028	14,092,309	4,431,685	2,112,717	6,544,402
14 RATE OF RETURN	RR			11.05	11.14	10.79	10.48	10.37	10.44

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	JACKSON PURCHASE (G)
1 OPERATING INCOME BEFORE TAX	OPY			6,560,443	3,576,099
DEVELOPMENT OF FED INC TAX					
ADDITIONS TO INCOME					
2 PROV FOR DEFERRED TAX	TOTDEF			606,083	299,049
3 INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
4 TOTAL ADDITIONS	TADD			1,235,690	607,691
DEDUCTIONS FROM INCOME					
5 INTEREST (.0461 X RATE BASE)	DED5			2,107,009	1,024,454
6 EXCESS BK DEP ON ST LN	DED11	QDED11	P00	-133,692	-65,792
7 TOTAL DEDUCTIONS	TDED			2,004,882	974,195
8 TAXABLE INCOME	FINI			5,791,252	3,209,595
TOTAL FED & STATE INC TAXES					
9 INC TAX @ 49.240% EFF RATE	IT			2,851,612	1,580,405
10 CURRENT FED & STATE INC TAX	TXLB			1,615,922	972,713
11 PROV FOR DEFERRED TAX	TOTDEF			606,083	299,049
12 INVEST TAX CREDIT ADJ	TOTITC			627,607	308,642
13 RETURN	RET			4,944,521	2,603,386
14 RATE OF RETURN	RR			10.82	11.72

TABLE 11

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 C-IP
PHASE I

	OUT IN ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
DEMAND RELATED ALLOCATION FACTORS							
1 DEMAND (AVG KW GEN LEVEL)	D10	1,871,450	1,509,996	361,454	117,829	54,747	172,576
2 DEMAND (AVG KW GEN LEVEL)	D11	1,744,792	1,509,996	234,796	117,829	54,747	172,576
ENERGY RELATED ALLOCATION FACTORS							
3 ENERGY (MWH AT GEN LEVEL)	E10	10,832,599	8,805,456	2,027,143	670,350	317,528	987,878
4 ENERGY (MWH AT GEN LEVEL	E11	10,832,599	8,805,456	2,027,143	670,350	317,528	987,878
5 ENERGY (MWH AT CUST LEVEL)	E99	10,119,037	8,149,254	1,969,783	652,787	305,464	958,251
CUSTOMER RELATED ALLOCATION FACTORS							
6 AVERAGE CUSTOMERS	C10	341,653	341,612	41	6	12	18
OTHER ALLOCATION FACTORS							
7 DIRECT ASSIGN OF DIST SUBS	DA612	1,233,294	0	1,233,294	67,202	1,166,092	1,233,294
8 DIRECT ASSIGN OF METERS	CA370	27,750,444	27,504,098	246,346	73,152	64,744	137,896
9 DIRECT ASSIGN OF ACCTS 902-5	CUSADA	8,270,228	8,258,064	12,164	3,603	3,582	7,185
10 ALL LABOR EXPENSES	LABOR	31,578,495	28,599,974	2,978,521	965,762	487,514	1,453,276
11 PROD-TRANSM PLANTS	PT	934,393,548	753,923,706	180,469,842	58,830,670	27,334,550	86,165,220
12 PROD-TRANSM-DISTR PLANTS	PTD	1,207,927,908	1,025,549,589	182,378,319	59,110,818	28,630,345	87,741,163
13 PROD-TRANSM-DISTR-GENL PLTS	PTDG	1,231,326,652	1,046,741,335	184,585,317	59,826,419	28,991,579	88,817,998
14 DIRECT ASSIGN-FCTY LEASE REV	DAFACL	16,631	0	16,631	16,631	0	16,631
15 DIRECT ASSIGN OF TAP LINES	DAJP	1,871,450	1,509,996	361,454	117,829	54,747	172,576
16 FUEL REQUIREMENT PERCENTAGES	EFUELP	0.309639	0.026575	0.283064	0.064110	0.059200	0.123310
17 PURCHASED POWER REQ. PERC.	EPURPC	0.167176	-0.001920	0.169096	0.035616	0.030712	0.066328

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE 1

	OUT	IN	ALLOC	FEDERAL JURISDICTOIN OLD DOMINION (F)	FEDERAL JURISDICTOIN JACKSON PURCHASE (G)
DEMAND RELATED ALLOCATION FACTORS					
1 DEMAND (AVG KW GEN LEVEL)	D10			126.658	62.220
2 DEMAND (AVG KW GEN LEVEL)	D11			0	62.220
ENERGY RELATED ALLOCATION FACTORS					
3 ENERGY (MWH AT GEN LEVEL)	E10			687.754	351.511
4 ENERGY (MWH AT GEN LEVEL	E11			687.754	351.511
5 ENERGY (MWH AT CUST LEVEL)	E99			673.243	338.289
CUSTOMER RELATED ALLOCATION FACTORS					
6 AVERAGE CUSTOMERS	C10			1	22
OTHER ALLOCATION FACTORS					
7 DIRECT ASSIGN OF DIST SUBS	DA612			0	0
8 DIRECT ASSIGN OF METERS	CA370			40.179	68.271
9 DIRECT ASSIGN OF ACCTS 902-5	CUSADA			2.314	2.665
10 ALL LABOR EXPENSES	LABOR			1.016.169	509.076
11 PROD-TRANSM PLANTS	PT			63.238.689	31.065.733
12 PROD-TRANSM-DISTR PLANTS	PTD			63.429.326	31.207.629
13 PROD-TRANSM-DISTR-GENL PLTS	PTDG			64.182.279	31.585.040
14 DIRECT ASSIGN-FCTY LEASE REV	DAFACL			0	0
15 DIRECT ASSIGN OF TAP LINES	DAJP			126.658	62.220
16 FULL REQUIREMENT PERCENTAGES	EFUELP			0.108877	0.050877
17 PURCHASED POWER REQ. PERC.	EPURPC			0.080384	0.022384

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1962

NO ORDER 298 CWIP
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DEVELOPMENT OF LABOR ALLOCATION FACTORS

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	PRIMARY (D)	TOTAL (E)
	PRODUCTION									
1	ENERGY RELATED	L911	K911	E10	4,820,430	3,918,366	902,064	298,301	141,298	439,599
2	DEMAND RELATED	L912	K912	D10	6,866,508	5,540,303	1,326,205	432,325	200,871	633,196
3	TOTAL PRODUCTION	L910			11,686,938	9,458,668	2,228,270	730,626	342,169	1,072,795
4	TRANSMISSION	L920	K920	D10	1,044,105	842,445	201,660	65,738	30,544	96,282
5	DISTRIBUTION	L930	K930	P30	6,670,154	6,623,616	46,538	6,831	31,598	38,429
6	TOTAL PTD	LPTD			19,401,197	16,924,729	2,476,468	803,195	404,311	1,207,506
7	CUSTOMER ACCOUNTING	L9015	K9015	CUSADA	5,347,600	5,339,735	7,865	2,330	2,316	4,646
8	SALES & CUST SERV & INFO	L9116	K9116	CRTAIL	1,590,278	1,590,278	0	0	0	0
9	ADMIN. & GENERAL	L950	K950	LABORX	5,239,420	4,745,232	494,168	160,237	80,887	241,124
10	ALL LABOR EXPENSES	LABOR			31,578,495	28,599,974	2,978,521	965,762	487,514	1,453,276

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

DEVELOPMENT OF LABOR ALLOCATION FACTORS

		OUT	IN	ALLOC	FEDERAL JURISDICTION OLD DOMINION (F)	FEDERAL JURISDICTION JACKSON PURCHASE (G)
	PRODUCTION					
1	ENERGY RELATED	L911	K911	E10	306.046	156.420
2	DEMAND RELATED	L912	K912	D10	464.719	228.290
3	TOTAL PRODUCTION	L910			770.765	384.710
4	TRANSMISSION	L920	K920	D10	70.664	34.713
5	DISTRIBUTION	L930	K930	P30	4.644	3.465
6	TOTAL PTD	LPTD			846.072	422.889
7	CUSTOMER ACCOUNTING	L9015	K9015	CUSADA	1.496	1.723
8	SALES & CUST SERV & INFO	L9116	K9116	CRTAIL	0	0
9	ADMIN. & GENERAL	L950	K950	LABORX	168.600	84.465
10	ALL LABOR EXPENSES	LABOR			1.016.169	509.076

TABLE 13

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATON: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD I
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
PHASE I

		OUT	IN	ALLOC	TOTAL KENTUCKY UTILITIES COMPANY	ALL OTHER (RETAIL) (A)	TOTAL AT ISSUE (B)	FEDERAL JURISDICTION — MUNICIPALS — TRANSMISSION (C)	FEDERAL JURISDICTION — MUNICIPALS — PRIMARY (D)	FEDERAL JURISDICTION — TOTAL (E)
1	RATE OF RETURN	RRT			11.230	11.230	11.230	11.230	11.230	11.230
2	SALES REVENUE REQUIREMENT	REVRQ			465,886,612	390,867,030	75,019,582	24,588,660	11,776,051	36,364,710
3	PRESENT SALES REVENUE	R10P			463,585,602	389,691,141	73,894,461	23,963,992	11,432,344	35,396,336
4	REV DEF(REVRQ-R10)	REVDEF			2,301,010	1,175,889	1,125,121	624,668	343,707	968,374
5	PERCENT REVENUE INCREASE	RPI			0.50	0.30	1.52	2.61	3.01	2.74

TABLE 13

RATE BASE:BEGIN & END AVG EXCEPT
13 MO AVG FOR TRANS & PROD
PRODUCTION ALLOCATGN: 12 CP

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
PERIOD 1
12 MONTHS ENDED DECEMBER 31, 1982

NO ORDER 298 CWIP
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		OUT	IN	ALLOC	---FEDERAL OLD DOMINION (F)	JURISDICTOIN--- JACKSON PURCHASE (G)
1	RATE OF RETURN	RRT			11.230	11.230
2	SALES REVENUE REQUIREMENT	REVRQ			25,727,299	12,927,573
3	PRESENT SALES REVENUE	R10P			25,357,633	13,140,492
4	REV DEF(REVRQ-R10)	REVDEF			369,666	-212,919
5	PERCENT REVENUE INCREASE	RPT			1.46	-1.62

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. 179

Responding Witness: William Steven Seelye

Q-179. With regard to KU Seelye Exhibit 11, please provide all detailed SAS output reports including diagnostic statistics, confidence intervals, number of observations, coefficients, etc.

A-179. The requested data is 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. 180

Responding Witness: William Steven Seelye

Q-180. Please provide all SAS stepwise selection and output reports generated during Mr. Seelye's KU weather normalization analysis.

A-180. See response to Question No. 179.

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. 181

Responding Witness: William Steven Seelye

Q-181. With regard to KU Seelye Exhibit 11, page 1, please explain what timing and size metrics the coefficients measure in terms of usage. In other words, do the coefficients relate to daily or monthly usage, sample size, or total class usage? If sample size, please explain in detail and provide all workpapers, analyses, and spreadsheets used to adjust from sample to population amounts.

A-181. The coefficients relate to total class daily usage.

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. 182

Responding Witness: William Steven Seelye

Q-182. Please provide all weather related data for all weather stations in KU's (or its Kentucky affiliates) possession (whether utilized or not in this case) in electronic format. Please provide in Microsoft Excel format if available. If not available in Excel format, please provide in ASCII, common delineated or fixed field format with all fields labeled or identified. In this response, include all weather stations for which data is available, all periods in which data in available, and all weather characteristics available (e.g., HDD, CDD, Max Temp, Min Temp, wind, etc.).

A-182. 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. 183

Responding Witness: William Steven Seelye

Q-183. Please identify the weather station(s) utilized by Mr. Seelye to conduct his KU weather normalization analyses.

A-183. Mr. Seelye utilized the Bluegrass Airport (LEX) weather station.

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. 184

Responding Witness: William Steven Seelye

Q-184. Please provide all source documents, analyses, and spreadsheets supporting Seelye KU Exhibit 9.

A-184. See response to PSC-2 Question No. 65.

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. 185

Responding Witness: William Steven Seelye

Q-185. With regard to Seelye KU Exhibit 11, please provide all input data (as selected) for each model in electronic format. Please provide in Microsoft Excel format if available. If Excel format is not available, please provide in ASCII common delineated or field format with all fields labeled or identified.

A-185. See response to PSC-2 Question No. 65. Also, see response to Question No. 178.

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. 186

Responding Witness: William Steven Seelye

Q-186. With regard to Seelye KU Exhibit 12:

a. please provide the Exhibit in executable Excel format (include all linked files); and,

b. using Index 1 (Residential Rate RS), month 5 as an example, please explain in detail how the "CDD70" value of -5509.5 was obtained as well as how the "max temp" value of -8481.352 was obtained. In this response, please also explain how the load data sample was applied to the entire class (population).

A-186. a. See response to PSC-2 Question No. 65. Also, see response to Question No. 178.

b. The value of -5509.5 was obtained by multiplying (i) the difference between the normal CDD70 plus one standard deviation (27 + 25 = 52) and actual CDD70 (= 64) (or 52 – 64 = -12) by (ii) the CDD70 coefficient for month 5 (= 459.125), which results in -5509.5. The value of -8481.352 was obtained by multiplying (i) the difference between the normal max temp plus one standard deviation (2300.2 + 111.6 = 2411.8) and actual max temp (= 2480.0) (or 2411.8 – 2480.0 = -68.2) by (ii) the max temp coefficient for month 5 (= 124.360), which results in -8481.352. The load data for entire population (either stratified from a sample or from census data) was to derive the coefficients and to calculate the normalization adjustments.

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. 187

Responding Witness: William Steven Seelye

Q-187. With regard to Mr. Seelye's KU direct testimony, page 34, lines 9 through 15, please explain in detail whether Mr. Seelye utilized the entire sample load research data available, or a subset of all sampled load research data observations (customer) in conducting his weather normalization regression analyses. If a subset of the total sampled load research data was utilized, please explain and provide all analyses showing how the selected sample reasonably reflects the usage characteristics of the class.

A-187. The entire sample load research data was utilized.