MISO Summary

	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005	April -June
Revenue Neutrality Uplift						
LG&E	395,233	732,797	1,632,156	2,104,768	1,608,726	2,760,186
KU	661,848	1,125,841	2,344,019	3,052,319	2,324,457	4,131,708
Total	1,057,082	1,858,637	3,976,175	5,157,087	3,933,183	6,891,894

NOTE:
Amount represents charges per the most recent settlement statements, or estimated amounts for days with no settlement statement, as of each month end allocated based upon an allocation methodology.

Revenue neutrality uplift charges for native load are allocated between companies based on the percent of load.
Revenue neutrality uplift charges for oss are allocated between companies based on the percent of generation contributed.

KU			Jan-2005		Feb-2005		Mar-2005		Apr-2005		May-2005		Jun-2005		Jul-2005		Aug-2005		2005 YTD	
		Acct #	MWH	Dollars	MWH	Dollars	MWH	Dollars	MWH	Dollars	MWH	Dollars	MWH	Dollars	MWH	Dollars	MWH	Dollars	MWH	Dollars
DAY 1	Schedule 7,8,14,18 - OSS	456051		(872,466.72)		(554,287.58)		(705,566.21)		26,834.84		(1,155.17)		(220.03)		(3,289.60)	-	(1,963.01)	-	(2,112,113.48)
	Schedule 1 - OSS	456052		(23,338.50)		(14,876.83)		(19,125.41)		725.87		(37.59)		(6.72)		(157.73)	-	(78.28)	-	(56,895.19)
	Schedule 2 - OSS	456053		(38,724.20)		(22,603.76)		(29,317.10)		1,119.81		(17.45)		(2.95)		(259.73)	-	(94.83)	-	(89,900.21)
	Transmission Elec OSS - MISO	565006				444,768.03		320,155.35	2	(9,876.83)	68	115.16	142	55.34	2,249	3,446.26	1,009	(162,056.29)	3,470	596,607.02
	MISO Schedule 10 - OSS	566102		14,129.28		(8,352.03)		14,137.73		(13,100.63)		11.55		20.35		323.00	-	(110.48)	-	7,056.77
	MISO FERC Fees - OSS	566104		5,068.00		5,068.00		5,068.00		5,068.00		5,068.00		5,068.00		3,458.95	-	17,886.23	-	51,753.18
	Subtotal Day 1 OSS			(915,332.14)		(150,284.17)		(414,647.64)	2	10,771.06	68	3,984.50	142	4,913.99	2,249	3,521.15	1,009	(146,416.66)	3,470	(1,603,489.91)
	Schedule 7,8,14,18 - NL	456002		(892,079.66)		239,077.69		(642,668.90)		(301,723.18)		(341,080.14)		(359,997.02)		(435,635.87)	-	32,788.64	-	(2,701,318.44)
	Schedule 1 - NL	456020		(14,632.61)		(14,110.41)		(14,915.88)		(11,782.58)		(12,957.63)		(11,913.36)		(13,272.69)	-	(14,495.29)	-	(108,080.45)
	Schedule 2 - NL	456021		(34,838.54)		(32,507.53)		(34,296.23)		(33,507.10)		(40,016.70)		(35,686.78)		(41,648.14)	-	(43,702.40)	-	(296,203.42)
	MISO Schedule 10 - NL	566101		429,229.69		326,174.61		427,304.36	1,945	267,544.24	2,409	347,282.73	2,763	383,959.06	3,114	437,667.98	3,002	412,621.63	13,234	3,031,784.30
	MISO Schedule 18 - NL	566109		7,807.19		8,118.76		6,652.98		7,395.76		5,498.84		6,467.04		7,624.16	-	8,360.42	-	57,925.15
	MISO FERC Fees - NL	566103		73,682.00		73,682.00		73,682.00		73,682.00		73,682.00		61,985.00		61,985.00	-	283,193.03	-	775,573.03
	Subtotal Day 1 NL		-	(430,831.93)	-	600,435.12	-	(184,241.67)	1,945	1,609.14	2,409	32,409.10	2,763	44,813.94	3,114	16,720.44	3,002	678,766.03	13,234	759,680.17
DAY 2	Regular Sales-OSS	447016	-	-	-	-	-	-	(7,081)	(317,003.10)	(9,732)	(471,544.65)	(32,469)	(1,594,507.32)	(77,005)	(3,384,860.69)	(75,540)	(4,273,698.15)	(201,827)	(10,041,613.91)
	Brokered Sales-OSS	447109	-	-	-	-	-	-	(20,709)	(712,579.85)	(31,229)	(1,099,492.15)	(29,210)	(1,239,913.66)	(26,260)	(1,623,500.14)	(34,507)	(1,822,103.69)	(141,915)	(6,497,589.49)
	Purchases-OSS	555006	-	-	-	-	-	-	153	8,871.49	253	12,164.40	(3)	(66.41)	69	6,509.09	8,710	1,203,120.75	9,182	1,230,599.32
	Brokered Purch.-OSS	447209	-	-	-	-	-	-	18,863	575,797.89	29,398	879,988.99	24,404	878,579.94	21,049	1,298,814.20	28,261	1,473,013.29	121,975	5,106,194.31
	Sch 17- DA/RT Admin Fee-OSS	557201	-	-	-	-	-	-		1,161.37		1,877.70	-	4,557.89		10,906.97	-	9,740.75	-	28,244.68
	RSG Make Whole Payment-OSS	557205/456025	-	-	-	-	-	-	-	(35,910.65)	-	(77,928.86)	-	(2,910,304.76)		(2,596,514.96)	-	(1,482,254.71)	-	(7,102,913.94)
	RSG Distribution Amount - OSS	557205	-	-	-	-	-	-	-	87.31	-	187.14	-	2,218.50		5,425.02	-	5,652.48	-	13,570.45
	Revenue Neutrality Uplift - OSS	557205	-	-	-	-	-	-	-	108.68	-	320.29	-	3,070.12		10,914.46	-	7,581.42	-	21,994.97
	Other-OSS	557205	-	-	-	-	-	-	-	26.14	-	(228.48)	-	(1,227.35)		(4,669.01)	-	(4,352.18)	-	(10,450.88)
	Day 2 OSS		-	-	-	-	-	-	(8,774)	(479,440.72)	(11,310)	(754,655.62)	(37,278)	(4,857,593.05)	(82,147)	(6,276,975.06)	(73,076)	(4,883,300.04)	(212,585)	(17,251,964.49)
	Generation fuel for MISO sales		-	-	-	-	-	-	6,918	183,983.46	9,335	344,323.98	32,298	1,549,009.04	75,628	1,952,159.26	74,479	2,453,268.71	198,658	6,482,744.45
	Internal replacement purch from LGE-fuel		-	-	-	-	-	-	-	-	-	-	257	16,313.42	1,216	94,918.88	1,022	86,013.02	2,495	197,245.32
	Subtotal Day 2 OSS		-	-	-	-	-	-	(1,856)	(295,457.26)	(1,975)	(410,331.64)	(4,723)	(3,292,270.59)	(5,303)	(4,229,896.92)	2,425	(2,344,018.31)	(11,432)	(10,571,974.72)
	Purchases-NL	555007	-	-	-	-	-	-	53,416	2,725,057.10	22,631	914,871.90	48,761	3,856,706.79	102,415	8,854,999.07	127,569	12,303,731.02	354,792	28,655,365.88
	Sch 16 - FTR Admin Fee-NL	557202	-	-	-	-	-	-		61,549.47		72,460.33	-	8,739.80		18,717.56	-	43,449.36	-	204,916.52
	Sch 17- DA/RT Admin Fee-NL	557203	-	-	-	-	-	-		270,660.06		287,420.52	-	310,687.12		404,479.69	-	388,618.98	-	1,661,866.37
	RSG Make Whole Payment-NL	557204								(436,590.82)		(281,401.50)		682,606.40		(17,335.77)		24,093.77	-	(28,627.92)
	RSG Distribution Amount - NL	557204	-	-	-	-	-	-	-	531,795.43	-	633,529.38	-	1,564,536.35		1,572,799.76	-	2,198,570.60	-	6,501,231.52
	Revenue Neutrality Uplift - NL	557204	-	-	-	-	-	-	-	661,739.67	-	1,125,520.24	-	2,340,949.26		3,041,404.17	-	2,316,875.74	-	9,486,489.08
	Other-NL	557204	-	-	-	-	-	-		(134,603.78)		(734,961.59)	-	(451,200.11)		(1,153,085.58)	-	(1,318,863.83)	-	(3,792,714.89)
	Day 2 NL		-	-	-	-	-	-	53,416	3,679,607.13	22,631	2,017,439.28	48,761	8,313,025.61	102,415	12,721,978.90	127,569	15,956,475.64	354,792	42,688,526.56
	FAC Revenue (100% of NL purch)		-	-	-	-	-	-	(53,416)	(2,725,057.10)	(22,631)	(914,871.90)	(48,761)	(3,856,706.79)	(102,415)	(8,854,999.07)	(127,569)	(12,303,731.02)	(354,792)	(28,655,365.88)
	Subtotal Day 2 NL		-	-	-	-	-	-	-	954,550.03	-	1,102,567.38	-	4,456,318.82	-	3,866,979.83	-	3,652,744.62	-	14,033,160.68
DAY 3	MISO Schedule 21 - NL	456002				(543,702.67)		(181,233.77)		(95,922.69)		(80,974.53)		(49,912.67)		(88,340.43)	0	(88,944.88)	-	(1,129,031.64)
	MISO Schedule 22 - NL	566117				26,535.12		164,064.60		43,735.07		43,264.62		71,606.20		98,405.18	0	(60,109.16)	-	387,501.63
	Subtotal Day 3 NL		-	-	-	(517,167.55)	-	(17,169.17)	-	(52,187.62)	-	(37,709.91)	-	21,693.53	-	10,064.75	-	(149,054.04)	-	(741,530.01)
	KU Subtotal per General Ledger		-	(1,346,164.07)	-	(67,016.60)	-	(616,058.48)	91.44	619,285.35	502.07	690,919.43	(1,818.36)	1,235,469.69	60.38	(332,610.75)	6,436.04	1,692,021.64	5,272	1,875,846.21
	Less Subtotal Day 2 OSS		-	-	-	-	-	-	1,856	295,457.26	1,975	410,331.64	4,723	3,292,270.59	5,303	4,229,896.92	(2,425)	2,344,018.31	11,432	10,571,974.72
	KU Total MISO less Day 2 OSS Profit		-	(1,346,164.07)	-	(67,016.60)	-	(616,058.48)	1,947	914,742.61	2,477	1,101,251.07	2,905	4,527,740.28	5,363	3,897,286.17	4,011	4,036,039.95	16,704	12,447,820.93

NOTE: Positive values represent Expenses and Negative values represent Revenues.

Blake Exhibit 1
Reference Schedule 1.45
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Annualize MISO Revenue Sufficiency Guarantee
For the Twelve Months Ended June 30, 2005

Revenue	April-June 2005	July-August 2005	
1. RSG Make Whole Payments	$9,787,489	$ 4,334,701	$ 14,122,190
2. RSG Make Whole Payment monthly amount (Line 1 / 5)			2,824,438
3. RSG Make Whole Payment annual amount (Line 2 x 12)			33,893,256
4. RSG Make Whole Payments earned during 12 months ended June 30, 2005 (Line 1 for April-June 2005)			9,787,489
5. Annualized Revenue Adjustment (Line 3 - Line 4)			$ 24,105,767
Expenses			
6. Production cost for RSG Payments	5,236,271	2,250,153	$ 7,486,424
7. RSG Distribution Amount	2,732,354	3,782,448	6,514,802
8. Monthly Expense amount [(Line 6 + Line 7) / 5]			2,800,245
9. Annual Expense Amount (Line 8 x 12)			33,602,940
10. MISO RSG Expenses incurred during 12 months ended June 30, 2005 (Line 6 + Line 7 for April-June 2005)			7,968,625
11. Annualized Expense Adjustment (Line 9 - Line 10)			$ 25,634,315
12. Net Adjustment (Line 5 - Line 11)			$ (1,528,548)
13. Kentucky Jurisdiction			86.080%
14. Kentucky Jurisdictional adjustment			$ (1,315,774)

MISO Summary

	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005	April -June
RSG Make Whole Payment						
RSG Reclassification	1,061,595	1,357,464	4,308,900	262,689		
LG&E	183,445	1,359,466	4,274,369	2,787,935	954,529	5,817,281
KU	1,534,096	1,716,795	6,536,598	2,876,540	1,458,161	9,787,489
Total	1,717,542	3,076,261	10,810,967	5,664,475	2,412,690	15,604,770
RSG Distribution Amount						
LG&E	317,622	415,546	1,105,768	1,083,018	1,508,474	1,838,937
KU	531,883	633,717	1,566,755	1,578,225	2,204,223	2,732,354
Total	849,505	1,049,262	2,672,523	2,661,243	3,712,697	4,571,291

NOTE:
Amount represents charges per the most recent settlement statements, or estimated amounts for days with no settlement statement, as of each month end allocated based upon an allocation methodology.

Revenue Sufficiency Guarantee make-whole payment is not allocated to for native load.
Revenue Sufficiency Guarantee make-whole payments for oss are allocated between companies based on the percent of unit ownership.
RSG Distribution charges for native load are allocated between companies based on the percent of load.
RSG Distribution charges for oss are allocated between companies based on the percent of generation contributed.

Determination of RSG Make Whole Payment production cost using simple ratio of OSS production expense

		Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005	April -June
LG&E Sales							
OSS Revenues [1]		14,425,519	19,501,205	16,273,168	6,380,374	13,312,090	50,199,892
RSG Make Whole Payment	(a)	183,445	1,359,466	4,274,369	2,787,935.16	954,529.38	5,817,281
Total	(b)	14,608,964	20,860,672	20,547,537	9,168,310	14,266,620	56,017,173
RSG Percentage	(a) / (b)	1.26%	6.52%	20.80%	30.41%	6.69%	
Cost of Total Sales [2]	(c)	11,776,239	18,804,666	15,869,688	5,818,491	10,898,916	46,450,593
Cost Attributable to RSG	(a)/(b) * (c)	147,875	1,225,479	3,301,267	1,769,309	729,208	4,674,621
RSG Revenues	(d)	183,445	1,359,466	4,274,369	2,787,935.16	954,529.38	5,817,280.90
RSG Expenses							
Distribution Amount	(e)	317,622	415,546	1,105,768	1,083,018.34	1,508,473.78	1,838,937
Cost of Sales	(f)	147,875	1,225,479	3,301,267	1,769,309.29	729,208.15	4,674,621
RSG Net	(d) - (e) - (f)	(282,052)	(281,558)	(132,666)	(64,392)	(1,283,153)	(696,276)
KU Sales							
Revenue from Foreign Sales [1]		5,157,811	8,553,721	7,692,007	7,192,285	10,018,698	21,403,540
RSG Make Whole Payment	(a)	1,534,096	1,716,795	6,536,598	2,876,540	1,458,161	9,787,489
Total	(b)	6,691,907	10,270,516	14,228,605	10,068,825	11,476,859	31,191,029
RSG Percentage	(a) / (b)	22.92%	16.72%	45.94%	28.57%	12.71%	
Cost of Total Sales [2]	(c)	4,182,007	6,913,024	6,795,836	4,430,050	7,749,109	17,890,867
Cost Attributable to RSG	(a)/(b) * (c)	958,711	1,155,565	3,121,996	1,265,611	984,542	5,236,271
RSG Revenues	(d)	1,534,096	1,716,795	6,536,598	2,876,539.91	1,458,160.94	9,787,488.96
RSG Expenses							
Distribution Amount	(e)	531,883	633,717	1,566,755	1,578,224.78	2,204,223.08	2,732,354.11
Cost of Sales	(f)	958,711	1,155,565	3,121,996	1,265,611.17	984,541.91	5,236,270.87
RSG Net	(d) - (e) - (f)	43,503	(72,486)	1,847,847	32,704	(1,730,604)	1,818,864

[1] Equal to the summation of the External and Intercompany OSS Revenues from the OSS Margn Detail sheet.
[2] Cost of Total Sales is equal to the summation of the Purchase Power, Generation for I/C Sales, and OSS Generation Expense from the OSS Margin Detail sheet.

KU		Acct #	Jan-2005 MWH	Jan-2005 Dollars	Feb-2005 MWH	Feb-2005 Dollars	Mar-2005 MWH	Mar-2005 Dollars	Apr-2005 MWH	Apr-2005 Dollars	May-2005 MWH	May-2005 Dollars	Jun-2005 MWH	Jun-2005 Dollars	Jul-2005 MWH	Jul-2005 Dollars	Aug-2005 MWH	Aug-2005 Dollars	2005 YTD MWH	2005 YTD Dollars
DAY 1	Schedule 7,8,14,18 - OSS	456051		(872,466.72)		(554,287.58)		(705,566.21)		26,834.84		(1,155.17)		(220.03)		(3,289.60)	-	(1,963.01)	-	(2,112,113.48)
	Schedule 1 - OSS	456052		(23,338.50)		(14,876.83)		(19,125.41)		725.87		(37.59)		(6.72)		(157.73)	-	(78.28)	-	(56,895.19)
	Schedule 2 - OSS	456053		(38,724.20)		(22,603.76)		(29,317.10)		1,119.81		(17.45)		(2.95)		(259.73)	-	(94.83)	-	(89,900.21)
	Transmission Elec OSS - MISO	565006				444,768.03		320,155.35	2	(9,876.83)	68	115.16	142	55.34	2,249	3,446.26	1,009	(162,056.29)	3,470	596,607.02
	MISO Schedule 10 - OSS	566102		14,129.28		(8,352.03)		14,137.73		(13,100.63)		11.55		20.35		323.00	-	(110.48)	-	7,058.77
	MISO FERC Fees - OSS	566104		5,068.00		5,068.00		5,068.00		5,068.00		5,068.00		5,068.00		3,458.95	-	17,886.23	-	51,753.18
	Subtotal Day 1 OSS			(915,332.14)		(150,284.17)		(414,647.64)	2	10,771.06	68	3,984.50	142	4,913.99	2,249	3,521.15	1,009	(146,416.66)	3,470	(1,603,489.91)
	Schedule 7,8,14,18 - NL	456002		(892,079.66)		239,077.69		(642,668.90)		(301,723.18)		(341,080.14)		(359,997.02)		(435,635.87)	-	32,788.64	-	(2,701,318.44)
	Schedule 1 - NL	456020		(14,632.61)		(14,110.41)		(14,915.88)		(11,782.58)		(12,957.63)		(11,913.36)		(13,272.69)	-	(14,495.29)	-	(108,080.45)
	Schedule 2 - NL	456021		(34,838.54)		(32,507.53)		(34,296.23)		(33,507.10)		(40,016.70)		(35,686.78)		(41,648.14)	-	(43,702.40)	-	(296,203.42)
	MISO Schedule 10 - NL	566101		429,229.69		326,174.61		427,304.36	1,945	267,544.24	2,409	347,282.73	2,763	383,959.06	3,114	437,667.98	3,002	412,621.63	13,234	3,031,784.30
	MISO Schedule 18 - NL	566109		7,807.19		8,118.76		6,652.98		7,395.76		5,498.84		6,467.04		7,624.16	-	8,360.42	-	57,925.15
	MISO FERC Fees - NL	566103		73,682.00		73,682.00		73,682.00		73,682.00		73,682.00		61,985.00		61,985.00	-	283,193.03	-	775,573.03
	Subtotal Day 1 NL		-	(430,831.93)	-	600,435.12	-	(184,241.67)	1,945	1,609.14	2,409	32,409.10	2,763	44,813.94	3,114	16,720.44	3,002	678,766.03	13,234	759,680.17
DAY 2	Regular Sales-OSS	447016	-	-	-	-	-	-	(7,081)	(317,003.10)	(9,732)	(471,544.65)	(32,469)	(1,594,507.32)	(77,005)	(3,384,860.69)	(75,540)	(4,273,698.15)	(201,827)	(10,041,613.91)
	Brokered Sales-OSS	447109	-	-	-	-	-	-	(20,709)	(712,579.85)	(31,229)	(1,099,492.15)	(29,210)	(1,239,913.66)	(26,260)	(1,623,500.14)	(34,507)	(1,822,103.69)	(141,915)	(6,497,589.49)
	Purchases-OSS	555006	-	-	-	-	-	-	153	8,871.49	253	12,164.40	(3)	(66.41)	69	6,509.09	8,710	1,203,120.75	9,182	1,230,599.32
	Brokered Purch.-OSS	447209	-	-	-	-	-	-	18,863	575,797.89	29,398	879,988.99	24,404	878,579.94	21,049	1,298,814.20	28,261	1,473,013.29	121,975	5,106,194.31
	Sch 17- DA/RT Admin Fee-OSS	557201	-	-	-	-	-	-		1,161.37		1,877.70	-	4,557.89		10,906.97	-	9,740.75	-	28,244.68
	RSG Make Whole Payment-OSS	557205/456025	-	-	-	-	-	-	-	(35,910.65)	-	(77,928.86)	-	(2,910,304.76)		(2,596,514.96)	-	(1,482,254.71)	-	(7,102,913.94)
	RSG Distribution Amount - OSS	557205	-	-	-	-	-	-	-	87.31	-	187.14	-	2,218.50		5,425.02	-	5,652.48	-	13,570.45
	Revenue Neutrality Uplift - OSS	557205	-	-	-	-	-	-	-	108.68	-	320.29	-	3,070.12		10,914.46	-	7,581.42	-	21,994.97
	Other-OSS	557205	-	-	-	-	-	-	-	26.14	-	(228.48)	-	(1,227.35)		(4,669.01)	-	(4,352.18)	-	(10,450.88)
	Day 2 OSS		-	-	-	-	-	-	(8,774)	(479,440.72)	(11,310)	(754,655.62)	(37,278)	(4,857,593.05)	(82,147)	(6,276,975.06)	(73,076)	(4,883,300.04)	(212,585)	(17,251,964.49)
	Generation fuel for MISO sales		-	-	-	-	-	-	6,918	183,983.46	9,335	344,323.98	32,298	1,549,009.04	75,628	1,952,159.26	74,479	2,453,268.71	198,658	6,482,744.45
	Internal replacement purch from LGE-fuel		-	-	-	-	-	-	-	-	-	-	257	16,313.42	1,216	94,918.88	1,022	86,013.02	2,495	197,245.32
	Subtotal Day 2 OSS		-	-	-	-	-	-	(1,856)	(295,457.26)	(1,975)	(410,331.64)	(4,723)	(3,292,270.59)	(5,303)	(4,229,896.92)	2,425	(2,344,018.31)	(11,432)	(10,571,974.72)
	Purchases-NL	555007	-	-	-	-	-	-	53,416	2,725,057.10	22,631	914,871.90	48,761	3,856,706.79	102,415	8,854,999.07	127,569	12,303,731.02	354,792	28,655,365.88
	Sch 16 - FTR Admin Fee-NL	557202	-	-	-	-	-	-		61,549.47		72,460.33	-	8,739.80		18,717.56	-	43,449.36	-	204,916.52
	Sch 17- DA/RT Admin Fee-NL	557203	-	-	-	-	-	-		270,660.06		287,420.52	-	310,687.12		404,479.69	-	388,618.98	-	1,661,866.37
	RSG Make Whole Payment-NL	557204								(436,590.82)		(281,401.50)		682,606.40		(17,335.77)		24,093.77	-	(28,627.92)
	RSG Distribution Amount - NL	557204	-	-	-	-	-	-	-	531,795.43	-	633,529.38	-	1,564,536.35		1,572,799.76	-	2,198,570.60	-	6,501,231.52
	Revenue Neutrality Uplift - NL	557204	-	-	-	-	-	-	-	661,739.67	-	1,125,520.24	-	2,340,949.26		3,041,404.17	-	2,316,875.74	-	9,486,489.08
	Other-NL	557204	-	-	-	-	-	-		(134,603.78)		(734,961.59)	-	(451,200.11)		(1,153,085.58)	-	(1,318,863.83)	-	(3,792,714.89)
	Day 2 NL		-	-	-	-	-	-	53,416	3,679,607.13	22,631	2,017,439.28	48,761	8,313,025.61	102,415	12,721,978.90	127,569	15,956,475.64	354,792	42,688,526.56
	FAC Revenue (100% of NL purch)		-	-	-	-	-	-	(53,416)	(2,725,057.10)	(22,631)	(914,871.90)	(48,761)	(3,856,706.79)	(102,415)	(8,854,999.07)	(127,569)	(12,303,731.02)	(354,792)	(28,655,365.88)
	Subtotal Day 2 NL		-	-	-	-	-	-	-	954,550.03	-	1,102,567.38	-	4,456,318.82	-	3,866,979.83	-	3,652,744.62	-	14,033,160.68
DAY 3	MISO Schedule 21 - NL	456002				(543,702.67)		(181,233.77)		(95,922.69)		(80,974.53)		(49,912.67)		(88,340.43)	0	(88,944.86)	-	(1,129,031.64)
	MISO Schedule 22 - NL	566117				26,535.12		164,064.60		43,735.07		43,264.62		71,606.20		98,405.18	0	(60,109.16)	-	387,501.63
	Subtotal Day 3 NL		-	-	-	(517,167.55)	-	(17,169.17)	-	(52,187.62)	-	(37,709.91)	-	21,693.53	-	10,064.75	-	(149,054.04)	-	(741,530.01)
	KU Subtotal per General Ledger		-	(1,346,164.07)	-	(67,016.60)	-	(616,058.48)	91.44	619,285.35	502.07	690,919.43	(1,818.36)	1,235,469.69	60.38	(332,610.75)	6,436.04	1,692,021.64	5,272	1,875,846.21
	Less Subtotal Day 2 OSS		-	-	-	-	-	-	1,856	295,457.26	1,975	410,331.64	4,723	3,292,270.59	5,303	4,229,896.92	(2,425)	2,344,018.31	11,432	10,571,974.72
	KU Total MISO less Day 2 OSS Profit		-	(1,346,164.07)	-	(67,016.60)	-	(616,058.48)	1,947	914,742.61	2,477	1,101,251.07	2,905	4,527,740.28	5,363	3,897,286.17	4,011	4,036,039.95	16,704	12,447,820.93

NOTE: Positive values represent Expenses and Negative values represent Revenues.

OSS Margin Detail
July 2004 through June 2005
$000s

	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Totals
LG&E						
External OSS Revenues	8,663	11,873	8,705	4,122	8,487	41,851
Intercompany OSS Revenues	5,762	7,628	7,568	2,259	4,825	28,041
Transmission Revenues	(5)	1	0	2	1	(1)
MISO Day 2 Revenues	1,213	2,550	8,929	3,037	995	16,724
Subtotal	15,633	22,052	25,203	9,419	14,308	86,615
Purchased Power	5,099	8,383	5,752	2,449	4,521	26,203
Generation for I/C Sales	5,763	7,646	7,556	2,316	4,648	27,928
OSS Generation Expense	915	2,776	2,562	1,054	1,730	9,037
Transmission Expense	(213)	29	18	18	(597)	(746)
Subtotal	11,563	18,833	15,887	5,836	10,302	62,422
LG&E OSS Margin	4,070	3,219	9,315	3,583	4,006	
KU						
External OSS Revenues	330	654	1,794	4,340	5,265	12,383
Intercompany OSS Revenues	4,828	7,900	5,898	2,852	4,754	26,232
Transmission Revenues	(29)	1	0	4	2	(21)
MISO Day 2 Revenues	36	78	2,910	2,597	1,557	7,177
Subtotal	5,165	8,633	10,603	9,793	11,578	45,771
Purchased Power	15	15	19	106	1,528	1,683
Generation for I/C Sales	3,929	6,383	6,349	2,119	3,367	22,146
OSS Generation Expense	238	516	428	2,205	2,854	6,241
Transmission Expense	(18)	(5)	15	7	(144)	(145)
Subtotal	4,164	6,908	6,811	4,437	7,605	29,925
KU OSS Margin	1,001	1,725	3,792	5,355	3,973	

Blake Exhibit 1
Reference Schedule 1.50
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Reclassification of MISO Revenue Sufficiency Guarantee
For the Twelve Months Ended June 30, 2005

	(1) RSG based on Generating Unit Ownership	(2) RSG based on Off-System Sales	(3) Adjustment (Col 1 - Col 2)
1. April 2005	$ 1,534,096	$ 472,501	$ 1,061,595
2. May 2005	1,716,795	359,330	1,357,465
3. June 2005	6,536,598	2,227,698	4,308,900
4. Total	$ 9,787,489	$ 3,059,529	$ 6,727,960
5. Kentucky Jurisdiction			86.080%
6. Kentucky Jurisdictional Adjustment			$ 5,791,428

Reclass RSG MWP from % of Gen Contributed split to % of Unit Ownership

		TOTAL DA	TOTAL RT	KU DA	KU RT	LGE DA	LGE RT
July	S14	$ 714,609.90	$ 4,079,681.35	$ 381,202.71	$ 2,191,026.32	$ 333,407.19	$ 1,888,655.03
	S55	$ -	$ -	$ -	$ -	$ -	$ -
Total Jul calced on % of ownership		$ 714,609.90	$ 4,079,681.35	$ 381,202.71	$ 2,191,026.32	$ 333,407.19	$ 1,888,655.03
Total DA/RT % of unit ownership							
Jul booked in GL		$ 4,832,978.67		$ 2,331,783.02		$ 2,501,195.65	
Variance		$ (38,687.42)		$ 240,446.01		$ (279,133.43)	
June	S14	$ 509,738.49	$ 10,172,025.93	$ 290,779.15	$ 6,034,789.81	$ 218,959.34	$ 4,137,236.12
	S55	$ -	$ -	$ -	$ -	$ -	$ -
Total Jun calced on % of ownership		$ 509,738.49	$ 10,172,025.93	$ 290,779.15	$ 6,034,789.81	$ 218,959.34	$ 4,137,236.12
Jun booked in GL		$ 10,681,763.85		$ 2,016,668.85		$ 8,665,095.00	
Variance		$ 0.57		$ 4,308,900.10		$ (4,308,899.53)	
May	S14	$ 483,880.54	$ 2,811,786.85	$ 277,014.02	$ 1,773,624.09	$ 206,866.52	$ 1,038,162.76
	S55	$ -	$ -	$ -	$ -	$ -	$ -
Total May calced on % of ownership		$ 483,880.54	$ 2,811,786.85	$ 277,014.02	$ 1,773,624.09	$ 206,866.52	$ 1,038,162.76
Total DA/RT % of unit ownership							
May booked in GL		$ 3,122,412.76		$ 574,112.27		$ 2,548,300.49	
Variance		$ 173,254.63		$ 1,476,525.85		$ (1,303,271.22)	
Apr	S14	$ 120,552.54	$ 1,552,222.30	$ 100,752.09	$ 1,257,749.23	$ 19,800.45	$ 294,473.07
	S55	$ 0.00	$ 139,207.61	$ 0.00	$ 107,342.12	$ -	$ 31,865.49
	S105	$ -	$ (26,585.88)	$ -	$ (24,751.32)	$ -	$ (1,834.56)
Total Apr calced on % of ownership		$ 120,552.55	$ 1,664,844.03	$ 100,752.09	$ 1,340,340.02	$ 19,800.45	$ 324,504.01
April booked in GL		$ 1,906,238.80		$ 462,540.66		$ 1,443,698.12	
Variance		$ (120,842.22)		$ 978,551.43		$ (1,099,393.66)	
Grand Total per % of ownership calc		$ 1,828,781.48	$ 18,728,338.16	$ 1,049,747.97	$ 11,339,780.24	$ 779,033.51	$ 7,388,557.92
Total DA/RT combined		$ 20,557,119.64		$ 12,389,528.21	60.2688%	$ 8,167,591.43	39.7312%
Grand Total booked to GL		$ 20,543,394.08		$ 5,385,104.82		$ 15,158,289.26	
Total Variance		$ 13,725.56		$ 7,004,423.39		$ (6,990,697.83)	

	TOTAL DA	TOTAL RT	KU DA	KU RT	LGE DA	LGE RT
June & July						
	$ 1,224,348.39	$ 14,251,707.28	$ 671,981.86	$ 8,225,816.12	$ 552,366.54	$ 6,025,891.16
	$ 15,476,055.67		$ 8,897,797.98	57.4940%	$ 6,578,257.69	42.5060%
	$ 15,514,742.52		$ 4,348,451.87		$ 11,166,290.65	
	$ (38,686.85)		$ 4,549,346.11	$ (22,242.60)	$ (4,588,032.96)	$ (16,444.25
			$ 4,571,588.71		$ (4,571,588.71)	
			credit 456025		debit 456025	
Apr & May						
	$ 604,433.09	$ 4,476,630.88	$ 377,766.12	$ 3,113,964.11	$ 226,666.97	$ 1,362,666.77
	$ 5,081,063.97		$ 3,491,730.23	68.7205%	$ 1,589,333.74	31.2795%
	$ 5,028,651.56		$ 1,036,652.95		$ 3,991,998.61	
	$ 52,412.41		$ 2,455,077.28	$ 36,018.04	$ (2,402,664.87)	$ 16,394.36
			$ 2,419,059.24		$ (2,419,059.24)	
			credit 557205		debit 557205	

	KU	LGE
July	$ 262,689.18	$ (262,689.18)
June	$ 4,308,899.53	$ (4,308,899.53)
May	$ 1,357,464.48	$ (1,357,464.48)
April	$ 1,061,594.76	$ (1,061,594.76)
	$ 6,990,647.95	$ (6,990,647.95)

Blake Exhibit 1
Reference Schedule 1.51
Sponsoring Witness: Kent Blake

KENTUCKY UTILITIES

Adjustment for EKPC Transmission Refund (FERC Order ER02-2560-002)
For the Twelve Months Ended June 30, 2005

1. EKPC Refund - Revenue	$	(987,749)
2. EKPC Refund included in 12 months ended June 30, 2005		164,909
3. Adjustment	$	822,840
4. Kentucky Jurisdiction		86.080%
5. Kentucky Jurisdictional adjustment	$	708,301

1.51

Charges		TOTAL Credits (no interest)		December 2004	November 2004	October 2004	September 2004	August 2004	July 2004	
Network Charge on Peak Demand (ex. Virginia facilities)					93,650.46	74,616.26	72,425.10	94,492.61	83,794.16	
Additional Network Charge if peak was below 80 MW	1	67,632.36			0.00	0.00	0.00	0.00	0.00	
Network Charge for Virginia Facilities	1	96,918.40			4,804.00	3,827.60	3,715.20	4,847.20	4,298.40	
Schedule 1 Charge on Peak Demand	1				6,193.82	4,934.94	4,790.03	6,249.52	5,541.95	
Additional Schedule 1 Charge if peak was below 80 MW	1	4,524.92			0.00	0.00	0.00	0.00	0.00	
Schedule 2 Charge on Peak Demand	1				12,970.80	10,334.52	10,031.04	13,087.44	11,605.68	
Additional Schedule 2 Charge if peak was below 80 MW	1	8,159.40			0.00	0.00	0.00	0.00	0.00	
Schedule 10					12,025.01	10,048.93	9,230.51	12,375.28	11,097.90	
Off-Peak Charge for over 120 MW	1	275,587.98			13,573.49	14,673.31	11,203.08	9,884.67	14,010.69	
					143,217.58	118,435.56	111,394.97	140,936.72	130,348.77	
Invoiced Amount					143,217.58	118,435.56	111,394.97	140,936.72	130,348.77	
Difference					0.00	0.00	0.00	0.00	0.00	
EKPC Credits		452,823.07			18,377.49	18,500.91	14,918.28	14,731.87	18,309.09	
Net Overpayment w/o interest		452,823.07 A			18,377.49	18,500.91	14,918.28	14,731.87	18,309.09	84,837 B
Cumulative Overpayment			415,944.66	401,026.38	401,026.38	386,294.51	367,985.42	351,711.51	332,148.90	
FERC Interest Rate				0.36%	0.35%	0.36%	0.33%	0.34%	0.34%	
Interest		17,430.39		1443.69	1403.59	1390.66	1214.35	1195.82	1129.31	
Net Overpayment with interest		**470,253.46**								
Demands and Energy of EKPC										
Peak Hour Transmission Demand (kW)					120,100	95,690	92,880	121,180	107,460	
Additional Off-Peak Hour Transmission Demand (kW)					19,870	21,480	16,400	14,470	20,510	
Energy					59,829.977	53,444.855	47,252.886	62,010.617	58,235.755	
Days in Month					30	31	30	31	31	
Rates Charged to EKPC										
Peak Hour Transmission Rate ($/kw-mo)					0.8197707	0.8197707	0.8197707	0.8197707	0.8197707	
Off-Peak Transmission Charge ($/kw-mo)					0.683114924	0.683114924	0.683114924	0.683114924	0.683114924	
Virginia Facilities adjustment ($/kw-mo)					0.04	0.04	0.04	0.04	0.04	
Schedule 1 Rate ($/kw-mo)					0.0515722	0.0515722	0.0515722	0.0515722	0.0515722	
Schedule 2 Rate ($/kw-mo)					0.108	0.108	0.108	0.108	0.108	
Schedule 10 Demand Rate ($/kw-mo)					0.08244	0.085188	0.078624	0.0812448	0.0809472	
Schedule 10 Energy Rate ($/mwh)					0.0355	0.0355	0.0408	0.0408	0.0412	

		TOTAL Credits (no Interest)	December 2004	November 2004	October 2004	September 2004	August 2004	July 2004	
Charges									
Baseline Transmission					99,330.00	93,170.00	105,490.00	109,340.00	
Baseline Credits (ex Virginia portion)					(23,856.30)	(7,920.13)	(13,637.41)	(11,397.13)	
Baseline Credits - Virginia Facilities	1	(15,891.40)			(1,223.76)	(406.28)	(699.56)	(584.64)	
Baseline Credit correction for wrong rate	1	(2,092.54)			(716.38)	(237.83)	(409.52)	(342.24)	
Baseline Schedule 1	1	163,865.46			4,431.19	5,420.70	6,037.25	6,380.10	
Baseline Schedule 2	1	306,542.66			9,279.58	11,351.77	12,642.91	13,360.90	
Baseline Schedule 10	1	245,815.11			9,023.14	10,445.85	11,954.94	12,776.32	
Excess Transmission (ex. Virginia portion)					23,136.58	56,050.70	63,746.25	74,460.30	
Excess Transmission - Virginia Facilities	1	71,322.16			1,186.84	2,875.24	3,270.00	3,819.60	
Excess Schedule 1					1,530.20	3,707.06	4,216.03	4,924.63	
Excess Schedule 2					3,204.47	7,763.15	8,829.00	10,312.92	
Excess Schedule 10					3,115.91	7,143.61	8,348.56	9,861.70	
Untelemetered Transmission (ex. Virginia Portion)					(445.25)	616.80	(150.50)	(18.71)	
Untelemetered Transmission - Virginia Portion	1	113.32			(22.84)	31.64	(7.72)	(0.96)	
Untelemetered Ancillary Charges					234.87	428.61	439.49	532.63	
					128,208.24	190,440.88	210,069.73	233,425.42	
Invoiced Amount					129,437.83	190,424.47	210,981.09	234,193.30	
Difference (Schedule 10 Energy for Untelemetered)					1,229.59	(16.42)	911.36	767.89	
EKPC Credits		769,674.78			21,957.77	29,481.09	32,788.30	35,409.07	
KU Credits		(163,906.48)			6,330.76	8,772.55	12,087.70	12,374.16	
Net Overpayment w/o Interest		534,925.65 A			15,627.01	20,708.54	20,700.60	23,034.92	80,072 B
Cumulative Overpayment			477,889.50	454,854.58	454,854.58	431,769.61	416,576.21	394,611.68	
FERC Interest Rate			0.36%	0.35%	0.36%	0.33%	0.34%	0.34%	
Interest		19,132.88	1720.4	1591.99	1637.48	1424.84	1416.36	1341.68	
Net Overpayment with Interest		**554,058.53**							
Demands and Energy of EKPC									
Baseline (kW)					129,000	121,000	137,000	142,000	
Coincident Peak(kW)					115,593	176,990	198,814	219,202	
Baseline Demands(kW)					85,922	105,109	117,064	123,712	
Excess Demands(kW)					29,671	71,881	81,750	95,490	
Untelemetered Demand(kW)					-571	791	-193	-24	
Net Baseline Load Reduction(kw)					30,594	10,157	17,489	14,616	
Load Factor					0.751	0.707	0.688	0.728	
Days in Month					31	30	31	31	
Rates Charged to EKPC									
Baseload Transmission Charge ($/kw-mo)					0.77	0.77	0.77	0.77	
Excess Transmission Charge ($/kw-mo)					0.8197707	0.8197707	0.8197707	0.8197707	
Virginia Facilities adjustment ($/kw-mo)					0.04	0.04	0.04	0.04	
Schedule 1 Rate ($/kw-mo)					0.0515722	0.0515722	0.0515722	0.0515722	
Schedule 2 Rate ($/kw-mo)					0.108	0.108	0.108	0.108	
Schedule 10 Demand Rate ($/kw-mo)					0.085188	0.078624	0.0812448	0.0809472	
Schedule 10 Energy Rate ($/mwh)					0.0355	0.0408	0.0408	0.0412	
Credits Transmisssion Charge ($/kw-mo)					0.8431863	0.8431863	0.8431863	0.8431863	
Untelemetered Ancillary Charges ($)					$234.87	$428.61	$439.49	$532.63	

UNITED STATES OF AMERICA 109 FERC ¶ 61,330
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Louisville Gas & Electric Company and Kentucky Utilities Company — Docket No. ER02-2560-002

v.

East Kentucky Power Cooperative, Inc.

ORDER AFFIRMING IN PART AND REVERSING IN PART INITIAL DECISION AND ESTABLISHING FURTHER HEARING PROCEDURES

(Issued December 22, 2004)

1. In this order, the Commission affirms in part and reverses in part an Initial Decision[1] resolving a proposal to modify the rates under an Interconnection Agreement and a Transmission Agreement (together, the Agreements) between Louisville Gas & Electric Company (Louisville Gas), Kentucky Utilities Company (Kentucky Utilities) and East Kentucky Power Cooperative, Inc. (East Kentucky). This order benefits customers because it assures that the rates, terms and conditions of the Agreements are just and reasonable.

I. Background

2. Kentucky Utilities and East Kentucky are parties to the Interconnection Agreement, which allows each to use the other's transmission system to avoid costly duplication of facilities. In May 1995, Kentucky Utilities and East Kentucky amended the Interconnection Agreement. The 1995 Amendment fixed the charges for service for so-called base load amounts for an initial ten-year period.[2] In February 1995, Kentucky

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[1] *Louisville Gas & Electric Company, Kentucky Utilities Company*, 106 FERC ¶ 63,039 (2004) (Initial Decision).

[2] The 1995 Amendment was accepted by letter order. *See Kentucky Utilities Company*, 72 FERC ¶ 61,097 (1995).

Utilities and East Kentucky entered into the Transmission Agreement for transmission service to the Gallatin Steel Company (Gallatin). The Transmission Agreement was also designed to avoid the cost of duplicate facilities.

3. After the Agreements were initially negotiated, Kentucky Utilities merged with Louisville Gas. Louisville Gas/Kentucky Utilities are transmission owning members of the Midwest Independent Transmission System Operator (Midwest ISO), but the Agreements are "grandfathered agreements" under the Midwest ISO Open Access Transmission Tariff (OATT), i.e., transmission service continues to be provided under the Agreements.

4. In September 2002, Louisville Gas/Kentucky Utilities filed with the Commission a proposal to restructure the Agreements to: (1) increase the rates paid by East Kentucky to the same rate Louisville Gas/Kentucky Utilities established pursuant to Attachment O of the Midwest ISO OATT as their zonal rate under the Midwest ISO OATT; (2) eliminate the reciprocal provision of ancillary services and add charges for ancillary services equal to the rates that Louisville Gas/Kentucky Utilities charge for ancillary services for their pricing zone under the Midwest ISO OATT, and pass through the costs that Louisville Gas/Kentucky Utilities incur under Schedule 10 of the Midwest ISO OATT (the Midwest ISO administrative cost adder); and (3) allow the automatic pass-through under the Agreements of charges under any future schedules that are added to the Midwest ISO OATT.

5. Louisville Gas/Kentucky Utilities essentially sought to "adjust the rates for certain transmission services provided to [East Kentucky] under the Agreements so that the charges reflect the corresponding charges that [East Kentucky] would pay if it were a transmission customer of the Midwest ISO."[3] In amending the Agreements, Louisville Gas/Kentucky Utilities sought to "eliminate the under-recovery of their transmission revenue requirement, including the Midwest ISO charges that they are assessed for service provided under the Agreements."[4]

6. The Commission accepted and suspended Louisville Gas/Kentucky Utilities' proposed rate changes and set the proposed rates for hearing.[5]

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[3] *Louisville Gas & Electric Company, Kentucky Utilities Company*, 101 FERC ¶ 61,182 (2002).

[4] *Id.*

[5] *Id.*

II. Initial Decision

7. The Initial Decision addressed eight issues: (1) whether Louisville Gas/Kentucky Utilities may charge for ancillary services; (2) whether Louisville Gas/Kentucky Utilities may add the Schedule 10 adder to the rates in the Agreements; (3) whether Louisville Gas/Kentucky Utilities may include in the rates under the Agreements the 50 basis point return on equity incentive adder approved for use under the Midwest ISO OATT; (4) whether East Kentucky should be charged the Midwest ISO Regional Through and Out Rate (Through & Out Rate) when it takes service under the Midwest ISO OATT to the border of the Louisville Gas/Kentucky Utilities system to import power to serve the load served under the Agreements; (5) whether Louisville Gas/Kentucky Utilities may include the cost of certain facilities in Virginia in the transmission rate; (6) whether Louisville Gas/Kentucky Utilities may automatically pass through under the Agreements charges under any future schedules that are added to the Midwest ISO OATT without making a new filing under section 205 of the Federal Power Act (FPA); (7) whether Louisville Gas/Kentucky Utilities' rates under Schedule 9 of the Midwest ISO OATT are just and reasonable for network service provided under the terms of the Agreements; and (8) what rates Louisville Gas/Kentucky Utilities should pay to East Kentucky under the Interconnection Agreement for service provided by East Kentucky.

8. The Presiding Judge found that: (1) Louisville Gas/Kentucky Utilities may not charge for ancillary services under the Agreements, other than Load Following and Load Regulation Service on loads that are not dynamically scheduled; (2) Louisville Gas/Kentucky Utilities may pass through the Midwest ISO Schedule 10 adder only for loads in excess of the base load amounts in the Agreements; (3) Louisville Gas/Kentucky Utilities may include the 50 basis point adder in rates for loads in excess of the base load amounts in the Agreements; (4) East Kentucky should be charged the Through & Out Rate only to import power to serve the base load amounts under the Agreements, not to serve any loads for which the Midwest ISO OATT rate has been adopted for service under the Agreements; (5) Louisville Gas/Kentucky Utilities must eliminate the cost of the Virginia facilities from the transmission rates it charges under the Agreements; (6) Louisville Gas/Kentucky Utilities may not automatically pass through under the Agreements charges under any future schedules that are added to the Midwest ISO OATT but instead must make a new filing under section 205 of the FPA; (7) Louisville Gas/Kentucky Utilities may charge the Midwest ISO Schedule 9 rates for network service only for loads in excess of the base load amounts in the Agreements; and (8) Louisville Gas/Kentucky Utilities should be charged the rates in East Kentucky's OATT for service they take from East Kentucky in excess of the base load amounts in the Agreements.

III. Discussion

9. After reviewing the record, the Initial Decision, and the briefs, we affirm, without further discussion, the Presiding Judge's findings in the Initial Decision, except for findings (1), (4), and (8) above, which we will discuss more fully below.

A. Ancillary Services

1. The Presiding Judge's Findings

10. The Presiding Judge agreed with East Kentucky's argument that there should be no separate charges for most ancillary services because the Interconnection Agreement fixed the charges for "area load service" for base load amounts and "area load service" includes more than just basic transmission service. He further found that this broad phrase was intended to continue the parties' long-standing practice of reciprocally providing each other with ancillary services at no charge, except for Load Following and Load Regulation Service for the 2 MW of untelemetered load specifically addressed in the Interconnection Agreement.

11. The Presiding Judge was also persuaded by Trial Staff's argument that the charge for base load service in the Interconnection Agreement already covers most ancillary services. The parties entered into the Interconnection Agreement in 1995, before Order No. 888 was issued, and at the time, charges for ancillary services were generally not unbundled from the charge for basic transmission service. Therefore, he found that the charge for base load amounts spelled out in section 8.03 of the Interconnection Agreement was intended to cover all ancillary services except for Load Following and Load Regulation Service for the 2 MW of load that is not dynamically scheduled.

12. The Presiding Judge also found that Louisville Gas/Kentucky Utilities' proposal to charge for particular ancillary services is contrary to the long-standing arrangement for reciprocal provision of ancillary services contained in the original Agreements. He found that because of dynamic scheduling, all but 2 MW of East Kentucky's load is dynamically scheduled back into its own control area, where East Kentucky performs "the bulk, if not all, of the ancillary services covered by Schedules 1, 3, 5, and 6 on that load."[6] Because each party is providing the bulk of these ancillary services for its own load served on the other's system due to dynamic scheduling, he found that there is no justification to add charges for these ancillary services.

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[6] *Id.* at P 46.

13. The Presiding Judge found that Schedule 2 service, Reactive Supply and Voltage Control from Generation Sources, cannot be self-provided through dynamic scheduling since, in this case, only Louisville Gas/Kentucky Utilities have generation close enough to East Kentucky's load to perform this service. However, he found that Schedule 2 service had not been treated separately from other ancillary services in the Agreements, but was provided on a reciprocal basis by the parties. The Presiding Judge found that which party ends up with most of the costs under the reciprocal arrangements cannot be determined on the record and that Louisville Gas/Kentucky Utilities cannot justify its proposal to charge for Schedule 2 service absent a demonstration that they incur substantially more costs than East Kentucky on the ancillary services overall because of the costs of that service.[7]

2. Louisville Gas/Kentucky Utilities' Brief on Exceptions

14. Louisville Gas/Kentucky Utilities claim that the Presiding Judge erred on this issue. They argue that the fixed rate for service for base load amounts is only for "transmission service" and that the Interconnection Agreement does not restrict Louisville Gas/Kentucky Utilities' right to propose changes to the compensation provisions for ancillary services for base load amounts.

15. Finally, Louisville Gas/Kentucky Utilities argue that the Presiding Judge erred in deciding that they failed to justify charging East Kentucky for ancillary services for load in excess of base load amounts because of the reciprocal provision of ancillary services and because the use of dynamic scheduling between Louisville Gas/Kentucky Utilities and East Kentucky. Louisville Gas/Kentucky Utilities argue that the reciprocal provision of ancillary services under the Interconnection Agreement does not restrict their right to propose changes to the rates, terms and conditions of service above the base load amounts. They further argue that while they do not seek to modify the reciprocal provision of ancillary services under the Interconnection Agreement, the reciprocal provision of those services is separate from the compensation for those services.

16. With respect to the Presiding Judge's finding that East Kentucky can self-provide Schedule 1 service, Louisville Gas/Kentucky Utilities cite to Order Nos. 888 and 888-A, where the Commission found that transmission providers that operate control areas are uniquely positioned to provide Schedule 1 service and required that, even in the case of dynamic scheduling, transmission providers provide Schedule 1 service and transmission customers must take Schedule 1 service from their transmission providers.[8] Therefore, Louisville Gas/Kentucky Utilities argue that the Presiding Judge's reasoning failed to follow Commission precedent with regard to Schedule 1 service.

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[7] *Id.* at P 50.

[8] Louisville Gas/Kentucky Utilities Briefs on Exceptions at 34-35.

3. East Kentucky, Gallatin and Trial Staff's Briefs Opposing Exceptions

17. East Kentucky opposes Louisville Gas/Kentucky Utilities' arguments, stating that the parties agreed to provide ancillary services on a reciprocal basis, that this intention was memorialized in the Interconnection Agreement, and that Louisville Gas/Kentucky Utilities' proposal to seek compensation for ancillary services is inconsistent with the reciprocal provisions in the Interconnection Agreement. East Kentucky argues that Louisville Gas/Kentucky Utilities have provided no evidentiary support for their argument that the ancillary services were not intended to be part of the transmission service.

18. Finally, East Kentucky opposes Louisville Gas/Kentucky Utilities' argument that the Presiding Judge failed to adhere to Order No. 888. East Kentucky argues that under Order No. 888 and later orders, the ancillary services prescribed by Order No. 888 are not required to be imported into grandfathered agreements, especially when those agreements do not provide compensation for such services. In addition, East Kentucky argues that the Midwest ISO OATT itself recognizes that the ancillary service provisions of the Midwest ISO OATT are not required to be included in grandfathered agreements.

19. Gallatin largely adopts the arguments that East Kentucky makes on this issue.

20. Commission Trial Staff echos East Kentucky's arguments on the ancillary services issue but adds that while East Kentucky is the control area for the dynamically scheduled load under both the Interconnection Agreement and the Transmission Agreement, Louisville Gas/Kentucky Utilities does not provide East Kentucky with Schedule 1 service on dynamically scheduled loads. Therefore, Trial Staff argues, Louisville Gas/Kentucky Utilities may not charge East Kentucky for Schedule 1 service on dynamically scheduled loads.

4. Commission Determination

21. The Commission agrees with the Presiding Judge that Louisville Gas/Kentucky Utilities cannot charge for ancillary services for base load amounts of transmission service (except for Load Following and Load Regulation Service for which separately stated rates already exist for load that is not dynamically scheduled).

22. The Interconnection Agreement in section 15.02(c) states that:

> [t]he charges for area load service for base load amounts as defined in section 8.03 ..., are fixed for the initial ten year term of this Agreement. It is the intent of the Parties to this Agreement to eliminate during the ten year initial term, solely with respect to said charges for area load service for base

> load amounts, [Kentucky Utilities'] right to make changes in said rates by making unilateral filings with the FERC pursuant to Section 205 of the [FPA] and [East Kentucky's] right to seek modification of such rates pursuant to section 206 of the [FPA] ... . As to all other rates, terms and conditions of service, or other provisions of this Agreement including rates for increases in service above base load amounts, which are subject to [Kentucky Utilities'] right of unilateral filing under section 205 of the [FPA], [East Kentucky] shall have the right to request modifications under section 206 of the [FPA] on the basis that they are unjust, unreasonable, unduly discriminatory, or preferential under the [FPA] or otherwise unlawful.[9]

23. The Commission agrees with the Presiding Judge's finding that the Interconnection Agreement prevents Louisville Gas/Kentucky Utilities from charging East Kentucky for ancillary services associated with transmission up to the base load amounts.

24. The Commission is not persuaded by Louisville Gas/Kentucky Utilities' argument that section 15.02(c) only applies to "transmission charges" and that that does not include ancillary services. To the contrary, the Commission is persuaded by the arguments that the Interconnection Agreement was executed before the issuance of Order No. 888 and that, before Order No. 888, costs associated with ancillary services were generally reflected in the basic "transmission charge." Contrary to this prevailing practice, the parties clearly specified a separate charge for Load Following and Load Regulation Service for load that is not dynamically scheduled. Because Load Following and Load Regulation Service for a portion of its load that is not dynamically scheduled is self-provided by East Kentucky, it makes sense that the charge for this service was separately stated and only applied to the portion of East Kentucky's base load for which Louisville Gas/Kentucky Utilities provide this service. In contrast, Schedule 1 and Schedule 2 service cannot be self-provided and must be provided by Louisville Gas/Kentucky Utilities for all load for which they provide transmission service to East Kentucky. Thus, there was no reason to deviate from the prevailing practice of including ancillary service costs in the basic transmission charge and separately state a rate for those services.

25. The Commission disagrees, however, with the Presiding Judge's finding that, under the terms of the Agreements, Louisville Gas/Kentucky Utilities cannot charge East Kentucky a separate rate for ancillary services above base load amounts. Section 15.02(c) of the Interconnection Agreement provides that "[t]he charges for area *base load amounts*... are fixed for the initial ten year term of this Agreement" and "[i]t is

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[9] *Redlined Copy of the Interconnection Agreement and Supplement No. 9 (entered into on June 26, 1998)*, LG&E/KU Exhibit No. 2.

the intent of the Parties to this Agreement to eliminate during the ten year initial term, *solely with respect to said charges for area load service for base load amounts [Louisville Gas/Kentucky Utilities'] right to make changes in said rates ... As to all other rates, terms and conditions of service, or other provisions of this Agreement including rates for increases in service above base load amounts*, which are subject to Louisville Gas/Kentucky Utilities' right of unilateral filing under section 205 of the [FPA]... "[10] This language provides Louisville Gas/Kentucky Utilities the right to unilaterally file under section 205 to modify the *rates, terms and conditions* of service above base load amounts; Louisville Gas/Kentucky Utilities may charge East Kentucky a separate rate for ancillary services above the base load amounts. The fact that the contract may have historically provided for ancillary services for service above base load amounts on a "return in kind" or exchange basis does not dictate that that practice must continue. Under Louisville Gas/Kentucky Utilities' proposal, each party will charge the other for all of the ancillary services that it provides the other. If one party incurs substantially more costs for the ancillary services that it provides the other, it will receive compensation for the difference. There is no need for Louisville Gas/Kentucky Utilities to show which party incurs more costs in order to find the proposal just and reasonable, as the Presiding Judge suggests.

26. In sum, after review of the record, the Initial Decision, and the parties' briefs, the Commission affirms the Presiding Judge's findings with respect to prohibiting Louisville Gas/Kentucky Utilities from charging East Kentucky a separate rate for ancillary services up to the base load amounts, but rejects the Presiding Judge's findings regarding Louisville Gas/Kentucky Utilities' right to charge East Kentucky for ancillary services above the base load amounts.

27. The Commission also disagrees with the Presiding Judge's finding that East Kentucky should not be charged for Schedule 1 service because it self-provides that service for its dynamically scheduled load. In Order No. 888, the Commission required that the transmission provider that operates a control area offer, and that the transmission customer must take and pay for, Schedule 1 service.[11] In Order No. 888-A, the Commission clarified that these requirements do not change when transmission service is taken for load that is dynamically scheduled and that, when load is dynamically scheduled from one control area to another, both control areas must provide Schedule 1 service.[12] By dynamically scheduling its load on the Louisville Gas/Kentucky Utilities system to the East Kentucky control area, East Kentucky will be able to match its generation with its load on a moment to moment basis, thus enabling it to self-provide

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[10] *Redlined Copy of the Interconnection Agreement and Supplement No. 9 (entered into on June 26, 1998) section 15.02(c)*, LG&E/KU Exhibit No. 2 (emphasis added).

[11] Order No. 888 at 31,715-16

[12] Order No. 888-A at 30,235-36.

load regulation, imbalance and reserve services, i.e., Schedules 3, 4, 5 and 6. However, Louisville Gas/Kentucky Utilities must monitor their transmission system, dispatch their transmission system, and direct the redispatch of generation resources, when necessary, to ensure that thermal and stability limits are not exceeded on the transmission system. This service, which Schedule 1 service includes, is necessary to support the transmission service that Louisville Gas/Kentucky Utilities provide, and it cannot be self-provided by East Kentucky through dynamic scheduling.

28. Further, East Kentucky and Gallatin and Trial Staff's argument that it is inconsistent with Order No. 888 and the Midwest ISO OATT to include charges for ancillary services in the Agreements is misplaced. In Order No. 888, the Commission did not generically abrogate existing transmission contracts and thus did not apply the requirements of that rule to existing transmission contracts.[13] However, parties to those contracts are free to seek modification to the contracts on a case by case basis consistent with their rights under those contracts and the FPA. This is what Louisville Gas/Kentucky Utilities have done. Likewise, the provisions for grandfathered agreements in the Midwest ISO OATT simply provided that service would continue to be provided under these agreements and that they were not modified by the Midwest ISO OATT. However, parties to those contracts were free to seek modification to those contracts on a case by case basis consistent with their rights under those contracts and the FPA, as Louisville Gas/Kentucky Utilities have done.

B. Regional Through and Out Rates

1. The Presiding Judge's Findings

29. The Presiding Judge explained that when East Kentucky imports energy from Midwest ISO transmission owners other than Louisville Gas/Kentucky Utilities to serve loads under the Agreements, it currently pays the Through & Out Rate in addition to the charges under the Agreements, and, thus, is subjected to rate pancaking. The Presiding Judge found that it would be unfair, discriminatory, and duplicative for Louisville Gas/Kentucky Utilities to adopt the Midwest ISO OATT rate for service under the Agreements and deny East Kentucky the elimination of rate pancaking for use of the Midwest ISO transmission system. If East Kentucky is paying the higher Midwest ISO rate, which presumes a single transmission rate in place of multiple pancaked rates, the Presiding Judge reasoned, it should be entitled to the benefits of the elimination of pancaked rates that it would enjoy as a network customer under the Midwest ISO OATT. Therefore, he found that for transmission service for load served under the Agreements on which the higher Midwest ISO rates are paid, East Kentucky may not also be charged the Midwest ISO Through & Out Rates.

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[13] Order No. 888 at 31,665.

2. Louisville Gas/Kentucky Utilities' Brief on Exceptions

30. Louisville Gas/Kentucky Utilities take exception to the Presiding Judge's holding that because of the manner in which Louisville Gas/Kentucky Utilities proposed to support the proposed rates, which was to use the formula rate under the Midwest ISO OATT, East Kentucky should be able to import energy from the Midwest ISO footprint without paying the Midwest ISO Through & Out Rates. Louisville Gas/Kentucky Utilities argue that the central issue here is whether the rates accurately reflect the cost of providing service under the Agreements and that there is no record evidence that the proposed rates fail to reflect Louisville Gas/Kentucky Utilities' cost of providing service under the Agreements. While elimination of rate pancaking can lead to lower revenue from off-system sales, which, in turn, leads to fewer revenue credits in the transmission cost-of-service, that reduction in revenue credits would be recognized in any transmission cost-of-service performed. Moreover, Louisville Gas/Kentucky Utilities maintain that, if East Kentucky wants to avoid paying Midwest ISO Through & Out Rate charges, Louisville Gas/Kentucky Utilities are willing to serve East Kentucky's contract loads as network customers under the Midwest ISO OATT.

3. East Kentucky's Brief Opposing Exceptions

31. East Kentucky states that the Initial Decision correctly determined that it should not have to pay the Midwest ISO Through & Out Rates for loads on the Louisville Gas/Kentucky Utilities transmission system if the Midwest ISO OATT rate for the Louisville Gas/Kentucky Utilities zone is adopted for the transmission service provided under the Agreements. According to East Kentucky, it pays the Through & Out Rate to move power originating in the Midwest ISO to serve East Kentucky loads in the Louisville Gas/Kentucky Utilities transmission system and, under Louisville Gas/Kentucky Utilities' proposal, also pays the Midwest ISO zonal rate for such transactions. Therefore, East Kentucky asserts that it is paying two separate, pancaked rates to serve its load located on the Louisville Gas/Kentucky Utilities system with resources from the Midwest ISO system, whereas other customers taking service under the Midwest ISO OATT would only pay the Midwest ISO zonal rate for use of the entire Midwest ISO system.

4. Commission Determination

32. We disagree with the Presiding Judge's finding that merely because the proposed service under the Agreements is at the same rate as the Midwest ISO OATT rate for load in the Louisville Gas/Kentucky Utilities' zone, East Kentucky is entitled to service over the entire Midwest ISO system. The issue in this proceeding is the just and reasonable rate for service under the Agreements. While the Presiding Judge is correct that the rate Louisville Gas/Kentucky Utilities proposes to charge here (again, a rate which matches the Midwest ISO OATT rate for load in the Louisville Gas/Kentucky Utilities zone) is

higher than the rate Louisville Gas/Kentucky Utilities would charge if Louisville Gas/Kentucky Utilities did not participate in the Midwest ISO, the appropriate solution is not to expand the scope of service under the Agreements to include access to the entire Midwest ISO system. Rather, the appropriate solution is to adjust the proposed rate, to reflect an allocation of costs to the Agreements assuming that Louisville Gas/Kentucky Utilities did not provide access to its system under the Midwest ISO OATT. However, such an adjustment cannot be made based on the record in this proceeding; indeed, no party even suggested that the proposed rate be adjusted to reflect the nature of the service. Therefore, we will remand the issue to the Presiding Judge and direct the Presiding Judge to conduct further proceedings to address the issue of what adjustment to the proposed rate is necessary.[14]

C. East Kentucky's Rates to Louisville Gas/Kentucky Utilities

1. The Presiding Judge's Findings

33. The Presiding Judge found that East Kentucky could not change its rates for service to Louisville Gas/Kentucky Utilities unless East Kentucky made a section 205 filing or by offering evidence during the hearing that would satisfy the requirements of section 205 of the FPA. Since East Kentucky did not offer any evidence to support a section 205 filing, the Presiding Judge found that East Kentucky must continue charging Louisville Gas/Kentucky Utilities the rates in the East Kentucky OATT for service above base load amounts.

2. East Kentucky's Brief on Exceptions

34. East Kentucky argues that, by ordering Louisville Gas/Kentucky Utilities to charge itself the rates provided under East Kentucky's OATT for service it takes from East Kentucky in excess of the base load amounts provided under the Agreements, the Presiding Judge restructured the stated rate design of the Interconnection Agreement. Thus, the Presiding Judge's findings allow Louisville Gas/Kentucky Utilities to alter the amount that East Kentucky charges Louisville Gas/Kentucky Utilities for load served on East Kentucky's system.

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[14] We encourage the parties to make every effort to settle this issue, rather than proceed to additional formal hearing procedures. We note that this issue could be resolved prospectively if East Kentucky accepted Louisville Gas/Kentucky Utilities' offer to allow East Kentucky to serve its contract loads under the Midwest ISO OATT rather than under the Agreements, in which case the rate adjustment would only be at issue for a limited, 'locked-in' period.

35. East Kentucky also argues that the Presiding Judge erred in stating that it did not present adequate evidence to support a change in the rate that it charges Louisville Gas/Kentucky Utilities. Furthermore, in proposing the new rate for charges to Louisville Gas/Kentucky Utilities, East Kentucky is just honoring the historic structure of the Agreements.

3. Commission Determination

36. The Commission disagrees with the Presiding Judge's finding on this issue. East Kentucky is a generation and transmission cooperative that holds RUS debt and, as such, is not a public utility subject to the Commission's jurisdiction under section 205 of the FPA.[15] Thus, the Commission finds that the Presiding Judge erred in finding that East Kentucky can only change the rates it charges for the service it provides under the Interconnection Agreement through a section 205 filing. The Commission has no power to entertain an East Kentucky section 205 filing regarding the rates it charges for the service it provides under the Interconnection Agreement.

The Commission orders:

(A) The Initial Decision is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) The proceeding is hereby remanded to the Presiding Judge who presided in the earlier hearing and the Presiding Judge shall conduct a further hearing to address the issue of what adjustment to the proposed rates is necessary.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

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[15] *Midwest Independent Transmission System Operator, Inc.; Public Utilities with Grandfathered Agreements in the MISO Region*, 108 FERC ¶ 63,013 at P. 58 (2004). This finding was originally made by an Administrative Law Judge and later accepted by the Commission in *Midwest Independent Transmission System Operator, Inc.; Public Utilities with Grandfathered Agreements in the MISO Region*, 108 FERC ¶ 61,236 (2004).

Blake Exhibit 1
Reference Schedule 1.60
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for VDT Net Savings to Shareholder
For the Twelve Months Ended June 30, 2005

1. Adjustment to reflect VDT Net Shareholder Savings		$ 4,680,000
2. Adjustment to remove VDT Net Shareholder Savings		$ (4,680,000)
2004 Shareholder's portion of VDT Savings	$ 4,320,000	
July - December 2004 (50%)	2,160,000	$ 2,160,000
2005 Shareholder's portion of VDT Savings	5,040,000	
January - June 2005 (50%)	2,520,000	2,520,000
		$ 4,680,000

VDT Settlement Surcredit

		2001	2002	2003	2004	2005	2006	
	Year	1	2	3	4	5	6	Total
LGE Electric	Est Savings	12.7	26.7	35.5	38	40.6	10.5	164
	Costs	10	23.9	23.9	23.9	23.9	6.1	111.7
	Net	2.7	2.8	11.6	14.1	16.7	4.4	52.3
	Sharing	40%	40%	40%	40%	40%	40%	40%
	Net Savings to cust.	$1,080,000	$1,120,000	$4,640,000	$5,640,000	$6,680,000	$1,760,000	$20,920,000
	Forecast Revenues	$38,269,000	$562,672,000	$604,931,000	$628,473,000	$644,137,000	$142,560,000	
	Factor	**2.82%**	**0.20%**	**0.77%**	**0.90%**	**1.04%**	**1.23%**	
LGE Gas	Est Savings	3.3	6.9	9.2	9.9	10.6	2.7	42.6
	Costs	3	6.1	6.1	6.1	6.1	1.6	29
	Net	0.3	0.8	3.1	3.8	4.5	1.1	13.6
	Sharing	40%	40%	40%	40%	40%	40%	40%
	Net Savings to cust.	$120,000	$320,000	$1,240,000	$1,520,000	$1,800,000	$440,000	$5,440,000
	Forecast Revenues	$44,151,000	$262,359,000	$229,902,000	$235,179,000	$251,654,000	$113,733,000	
	Factor	**0.27%**	**0.12%**	**0.54%**	**0.65%**	**0.72%**	**0.39%**	
KU Electric	Est Savings	6.2	13.1	17.4	18.7	19.9	5.1	80.4
	Costs	5	11.5	11.5	11.5	11.5	3	54
	Net	1.2	1.6	5.9	7.2	8.4	2.1	26.4
	Sharing	40%	40%	40%	40%	40%	40%	40%
	Net Savings to cust.	$480,000	$640,000	$2,360,000	$2,880,000	$3,360,000	$840,000	$10,560,000
	Forecast Revenues	$56,225,000	$657,955,000	$724,479,000	$757,809,000	$745,078,000	$191,180,000	
	Factor	**0.85%**	**0.10%**	**0.33%**	**0.38%**	**0.45%**	**0.44%**	

Blake Exhibit 1
Reference Schedule 1.61
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Remove VDT Surcredit and Cost Amortization
For the Twelve Months Ended June 30, 2005

1. Actual VDT surcredit refunded	$ (3,227,105)
2. VDT revenue adjustment	$ 3,227,105
3. VDT cost amortization	$ 11,753,520
4. VDT cost adjustment	$ (11,753,520)
5. Total adjustment	$ 14,980,625

Source: Revenue Volume Analysis

VDT Revenue		LGE Electric		LGE Gas		KU (Only)
YTD June 2005 Billed Revenue	+	$ (3,032,348.15)		$ (1,231,701.25)		$ (1,738,111.79)
YTD June 2005 Accruals	+	$ -		$ -		$ -
YTD Dec 2004 Billed Revenue	+	$ (5,637,918.42)		$ (1,444,740.87)		$ (2,871,243.69)
YTD Dec 2004 Accruals	+	$ -		$ -		$ -
YTD June 2004 Billed Revenue	-	$ (2,556,331.29)		$ (1,009,302.24)		$ (1,382,250.46)
YTD June 2004 Accruals	-	$ -		$ -		$ -
July 2004 thru June 2005	=	**$ (6,113,935.28)**		**$ (1,667,139.88)**		**$ (3,227,105.02)**
Gas Transport						
YTD June 2005 Billed Revenue	+			$ (14,352.23)		
YTD Dec 2004 Billed Revenue	+			$ (24,548.69)		
YTD June 2004 Billed Revenue	-			$ (14,212.46)		
July 2004 thru June 2005	=	**$ (6,113,935.28)**	[AT]	**$ (1,691,828.34)**	[BD]	**$ (3,227,105.02)**

KENTUCKY UTILITIES COMPANY
ANALYSIS OF CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL, SALES AND ADMINISTRATIVE AND GENERAL EXPENSES
JUNE 30, 2005

	CURRENT MONTH		YEAR TO DATE		YEAR ENDED CURRENT MONTH	
	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR
Customer Accounts Expenses						
Supervision	151,835.47	72,760.65	936,180.26	445,851.90	1,452,525.09	876,755.52
Meter Reading	713,598.86	677,320.64	4,202,141.44	4,106,730.20	8,328,099.09	8,339,221.89
Customer Service	239,664.93	194,558.90	1,414,258.05	1,169,322.87	2,825,017.79	2,316,141.44
Customer Billing and Accounting	265,914.44	74,727.52	1,577,743.51	403,521.45	4,228,656.63	1,982,481.03
Collecting	107,719.59	61,550.90	495,921.42	378,253.84	897,209.62	734,605.64
Miscellaneous Expenses	12,551.11	33,379.13	75,820.29	223,962.72	292,023.33	472,795.57
Provision for Uncollectible Accounts	136,669.59	241,858.37	460,732.18	584,654.27	1,122,769.72	1,131,160.16
Total	1,627,953.99	1,356,156.11	9,162,797.15	7,312,297.25	19,146,301.27	15,853,161.25
Customer Service and Information Expenses						
Supervision	16,995.92	20,830.86	94,642.18	122,410.24	212,563.10	235,311.07
Customer Assistance Expenses	326,680.13	334,862.77	2,028,562.92	1,917,278.51	4,438,621.14	3,783,885.54
Informational and Instructional Adv	10,971.74	4,461.37	115,271.38	26,563.53	184,490.94	233,497.79
Miscellaneous Expenses	55,314.28	40,391.40	126,792.33	233,472.20	350,154.13	460,306.95
Total	409,962.07	400,546.40	2,365,268.81	2,299,724.48	5,185,829.31	4,713,001.35
Sales Expenses						
Demonstrating & Selling Expenses	-	33,294.57	-	233,659.07	216,490.48	397,745.63
Advertising Expenses	-	-	-	75.00	-	795.00
Total	-	33,294.57	-	233,734.07	216,490.48	398,540.63
Administrative and General Expenses						
General Office Salaries	1,463,119.82	1,711,896.61	6,884,011.75	9,180,906.81	14,167,758.51	9,226,444.00
Office Supplies and Expenses	1,174,780.22	747,481.77	4,503,316.67	5,136,938.92	5,246,295.03	5,683,900.87
Administrative Expenses Trans. - Cr.	(157,695.91)	(216,267.43)	(631,144.77)	(645,417.43)	(2,010,192.90)	(1,177,466.46)
Outside Services Employed	941,424.51	797,505.79	3,364,464.31	3,214,841.01	7,377,826.63	13,330,812.45
Property Insurance	345,645.96	405,310.78	2,079,970.68	2,438,731.40	4,392,134.27	5,589,679.67
Injuries and Damages	139,441.63	130,668.14	904,335.00	813,553.22	1,171,514.01	1,758,379.71
Group Life Insurance	35,882.13	29,782.81	221,008.49	190,002.48	487,720.81	366,418.07
Hospitalization Expenses	512,486.89	474,769.22	3,142,943.66	3,010,621.19	5,672,875.50	5,259,429.87
Dental Expenses	44,196.76	43,499.55	269,253.57	279,473.81	394,856.50	551,932.72
Thrift Savings Expenses	139,090.58	107,672.88	853,654.54	(545,865.19)	1,481,794.37	389,685.43
Other Employee Welfare Expenses	674,829.53	698,684.18	4,182,938.90	4,515,300.96	7,888,359.83	8,932,754.06
Pensions	601,367.62	156,703.49	2,776,143.23	2,199,001.72	3,537,490.89	5,134,038.65
Franchise Requirements	236.45	209.95	1,371.63	1,308.90	2,657.66	2,616.64
Reg. Commission Expenses	-	20,579.00	-	120,579.00	(119,726.00)	120,579.00
General Advertising Expenses	-	63,221.92	13,855.00	404,251.44	179,269.25	341,774.11
Miscellaneous Expenses	55,493.57	8,285.50	1,078,464.84	725,162.90	1,820,381.56	751,491.21
Amortized Merger Expenses	-	-	-	-	-	-
Amortized VDT Expenses	979,460.00	979,460.00	5,876,760.00	5,876,760.00	11,753,520.00	11,753,520.00
Rents	98,619.63	83,423.74	585,570.48	499,849.24	1,121,783.94	503,468.99
Miscellaneous Credits	(236.45)	(209.95)	(1,371.63)	(1,308.90)	(2,657.66)	(2,616.64)
Maintenance of General Plant	373,640.86	30,387.42	2,235,680.08	59,256.27	5,610,185.18	2,314,759.10
Total	7,421,783.80	6,273,065.37	38,341,226.43	37,473,947.75	70,173,847.38	70,831,601.45

Blake Exhibit 1
Reference Schedule 1.70
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Calculation of Composite Federal and Kentucky Income Tax Rate (Based on Law in Effect June 30, 2005)

1. Assume pre-tax income of	$ 100.0000
2. State income tax at 7.00%	7.0000
3. Taxable income for Federal income tax	93.0000
4. Federal income tax at 35% (Line 3 x 35%)	32.5500
5. Total State and Federal income taxes (Line 2 + Line 4)	$ 39.5500

6. Therefore, the composite rate is:

7.	Federal	32.5500%
8.	State	7.0000%
9.	Total	39.5500%

Blake Exhibit 1
Reference Schedule 1.71
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Calculation of Current Tax Adjustment Resulting From "Interest Synchronization"

1. Adjusted Jurisdictional Capitalization - Exhibit 2	$	1,368,045,946
2. Weighted Cost of Debt - Exhibit 2		1.65%
3. "Interest Synchronization"		22,572,758
4. Kentucky Jurisdictional Interest per books (excluding other interest)		22,601,598
5. "Interest Synchronization" adjustment	$	28,840
6. Composite Federal and State tax rate		39.5500%
7. Current tax adjustment from "Interest Synchronization"	$	11,406

KENTUCKY UTILITIES COMPANY
ANALYSIS OF INTEREST CHARGES
JUNE 30, 2005

	CURRENT MONTH		YEAR TO DATE		YEAR ENDED CURRENT MONTH	
	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR
Interest On Long-Term Debt						
First Mortgage Bonds						
Series P 7.92%...	349,800.00	349,800.00	2,098,800.00	2,098,800.00	4,197,600.00	4,197,600.00
Series P 8.55%...	-	-	-	-	-	1,136,437.51
Series R 7.55%...	125,833.38	314,583.33	1,698,749.98	1,887,499.99	3,586,249.96	3,775,000.03
Series S 5.99%...	179,700.00	179,700.00	1,078,200.00	1,078,200.00	2,156,400.00	2,156,400.00
Loan Agreement - Poll. Control Bonds						
Series 9 (5 3/4%)	-	239,583.33	-	1,437,499.99	1,134,027.73	2,875,000.03
Series 10 (VARIABLE%)	107,896.44	51,432.79	621,754.38	300,629.49	1,037,367.34	593,708.96
Series 11 (VARIABLE%)	30,100.00	12,362.50	149,675.83	67,047.76	247,814.36	128,713.34
Series 12 (VARIABLE%)	49,371.86	21,581.91	236,064.62	118,278.10	399,847.66	231,534.50
Series 13 (VARIABLE%)	5,661.37	2,474.75	27,069.05	13,562.71	45,849.70	26,549.60
Series 14 (VARIABLE%)	5,661.37	3,817.70	27,067.08	37,081.57	45,843.47	76,042.21
Series 15 (VARIABLE%)	17,455.89	7,630.49	83,462.88	41,818.34	141,369.93	81,861.22
Series 16 (VARIABLE%)	227,733.33	90,026.67	1,109,733.34	492,240.01	1,925,120.02	1,036,013.34
Series 17 (VARIABLE%)	112,070.83	-	562,487.50	-	736,480.60	-
Interest Rate Swaps	(2,001,532.52)	(473,166.68)	(3,740,191.77)	(2,684,058.68)	(6,310,242.67)	(6,773,519.92)
Marked to Market	(209,727.00)	492,782.00	(500,154.00)	(2,087,186.00)	(877,367.00)	(314,149.00)
Fidelia...	1,153,683.33	1,153,683.34	6,922,099.98	6,864,326.93	13,816,611.91	10,834,705.28
Total...	153,708.28	2,446,292.13	10,374,818.87	9,665,740.21	22,282,973.01	20,061,897.10
Amortization of Debt Expense - Net						
Amortization of Debt Expense............................	20,095.63	21,126.70	127,678.54	127,145.77	255,633.49	259,151.91
Amort. of Loss on Reacquired Debt.....................	1,954,123.00	60,384.00	2,279,597.74	383,524.19	2,655,388.74	756,345.19
Total...	1,974,218.63	81,510.70	2,407,276.28	510,669.96	2,911,022.23	1,015,497.10
Other Interest Charges						
Customers' Deposits..	71,311.14	58,525.44	423,723.02	356,587.54	809,231.95	708,719.44
Deferred Compensation.....................................	-	5,631.01	-	11,730.56	12,001.98	24,415.25
Interest on Debt to Associated Companies	160,129.38	33,000.25	311,718.77	218,999.03	491,721.01	702,376.92
Interest Costs from A/R Securitization..............	-	-	-	(63,097.07)	9,597.45	314,299.22
Federal RAR Interest Reserve	-	-	-	-	-	-
AFUDC Borrowed Funds	(785.57)	(27,041.79)	(3,324.01)	(187,207.99)	(42,372.98)	(598,602.09)
Other Interest Expense.....................................	32,600.00	162,830.17	757,600.47	976,981.02	1,808,798.85	1,913,090.52
Total...	263,254.95	232,945.08	1,489,718.25	1,313,993.09	3,088,978.26	3,064,299.26
Total Interest..	2,391,181.86	2,760,747.91	14,271,813.40	11,490,403.26	28,282,973.50	24,141,693.46

Blake Exhibit 1
Reference Schedule 1.72
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Prior Period Income Tax True-Ups and Adjustments
For the Twelve Months Ended June 30, 2005

1. 2003 Income Tax True-up:	
2. Federal Tax (benefit)	$ (415,283)
3. State Tax (benefit)	(832,660)
4. Total 2003 Income Tax True-up	$ (1,247,943)
5. 2004-2005 Other Tax adjustments:	
6. Misc. Operating Tax Adjustments - 2004	$ (252,686)
7. Kentucky Coal Credit - 2004	(61,032)
8. Total 2004 & 2005 Other Tax adjustments:	$ (313,718)
9. Total adjustments (Line 4 + Line 8)	$ (1,561,661)
10. Kentucky Jurisdiction	88.846%
11. Kentucky Jurisdiction amount before KY Tax Changes	$ (1,387,473)
12. Kentucky Tax Rate Decrease -KY Jurisdiction	$ 185,000
13. Kentucky Jurisdiction amount (Line 11 + Line 12)	$ (1,202,473)
14. Kentucky Jurisdiction adjustment	$ 1,202,473

TAX RELATED ADJUSTMENTS FOR 12ME 6-30-2005

	PRE-TAX AMOUNTS					AFTER-TAX AMOUNTS			
	LG&E Electric	LG&E Gas	KU	Total	Tax Rate	LG&E Electric	LG&E Gas	KU	Total
First Quarter 2005:									
	-	-	-	-		-	-	-	-
Second Quarter 2005:									
KY Coal Credit (1st and 2nd qtr 2005	280,110		102,339	382,449	60%	167,051		61,032	228,083
KY Tax Rate Decrease (KY Juns Only)	190,000	(151,000)	(285,000)	(246,000)	65%	123,000	(98,000)	(185,000)	(160,000)
Sales Tax (error in June)	131,029	32,757	165,999	329,785	60%	78,142	19,535	98,998	196,676
	601,139	(118,243)	(16,662)	466,234		368,193	(78,465)	(24,970)	264,759
Third Quarter 2004:									
2002 Tax Return True-Ups - Federal	21,541	(24,737)	415,283	412,087		21,541	(24,737)	415,283	412,087
2002 Tax Return True-Ups - State	339,793	87,732	832,660	1,260,185		339,793	87,732	832,660	1,260,185
	361,334	62,995	1,247,943	1,672,272		361,334	62,995	1,247,943	1,672,272
Fourth Quarter 2004:									
VA Utility & Consumption & Sales			(59,863)	(59,863)	60%	-		(35,701)	(35,701)
Misc. Oper. Taxes (Reserve Adj)			156,092	156,092	60%	-		93,089	93,089
School Tax (Reserve Adj)	6,337		41,965	48,302	60%	3,779			3,779
Sales Tax (Reserve Adj)	(79,649)	(22,465)	161,476	59,362	60%	(47,501)	(13,398)	96,300	35,402
	(73,312)	(22,465)	299,670	203,893		(43,721)	(13,398)	153,689	96,570
Total 12ME 6/30/05	**889,161**	**(77,713)**	**1,530,951**	**2,342,399**		**685,806**	**(28,867)**	**1,376,662**	**2,033,600**

Note: Positive Adjustments reduce pro-forma income; Negative Adjustments increase pro-forma income.
No adjustments were made for the manufacturing deduction.

		2003 Tax Return True-Up			
Fed	2003 True-up (Recorded 9/30/04)	LG&E Electric	LG&E Gas	KU	Total
	Current Tax Expense ATL	1,714,456	(2,569,307)	8,696,501	7,841,650
	Deferred Tax Expense ATL	(1,735,997)	2,594,044	(9,111,784)	(8,253,737)
	Net	(21,541)	24,737	(415,283)	(412,087)
	Current Tax Expense BTL	(46,517)	(12,077)	11,050	(47,544)
	Deferred Tax Expense BTL	18,228	4,557	(29,702)	(6,917)
	Net	(28,289)	(7,520)	(18,652)	(54,461)
State	2003 True-up (Recorded 9/30/04)				
	Current Tax Expense ATL	(778,504)	(335,216)	864,703	(249,017)
	Deferred Tax Expense ATL	438,711	247,484	(1,697,363)	(1,011,168)
	Net	(339,793)	(87,732)	(832,660)	(1,260,185)
	Current Tax Expense BTL	(11,951)	(3,103)	2,840	(12,214)
	Deferred Tax Expense BTL	4,683	1,171	(7,630)	(1,776)
	Net	(7,268)	(1,932)	(4,790)	(13,990)

Blake Exhibit 1
Reference Schedule 1.73
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Tax Deduction for Manufacturing Activities (TDMA)
For the Twelve Months Ended June 30, 2005

1. TDMA Annual Amount for 2005	$ 2,000,000
2. TDMA included in 12 months ended June 30, 2005	1,000,000
3. TDMA Adjustment Amount (Line 1 - Line 2)	$ 1,000,000
4. Kentucky Jurisdiction	86.080%
5. Kentucky Jurisdictional amount	$ 860,800
6. Kentucky Jurisdictional adjustment	$ (860,800)
7. Composite Federal and State tax rate	39.5500%
8. Kentucky Jurisdictional TDMA Income Tax Adjustment	$ (340,446)

Kentucky Utilities
Income Taxes Year to Date
June 2005 (Year To Date)

Prepared by: S Bloat 7/7/05
Reviewed by:

FEDERAL		Year 2005	Effective Tax Rate		Effective Tax Rate W/O ITC
Pretax Book Income (year to date)		87,809,491			
Permanent Differences					
Exempt Interest	-				
Nontaxable Dividends	-				
Nondeductible Meals	68,518				
Various permanent differences	177,904				
Life insurance	-				
AFUDC	487,148				
Preferred Dividends paid	(123,500)				
Equity in subsidiary	(891,330)				
Manufacturing Deduction	(1,000,000)				
ESOP Dividends					
Total Permanent Differences		(1,281,260)			
Subtotal		86,528,231			
State Income Tax Deduction		(6,050,023)			
Taxable Income		80,478,208			
Effective Tax Rate		0.350000			
Tax		28,167,373	32.077800		
Amortization of ITC		(849,702)	(0.967700)		
Cushion Adjustment		-	-		
Deferred Tax Adjustments (203(e))		(1,000,000)	(1.138800)		
Deferred Tax Adjustments - Adj to Actual		-	-		
Deferred Tax Adjustments - Tax Rate Change		(121,632)	(0.138500)		
R&D Credit			-		
Reserve			-		
Adjusted Federal Tax		28,196,039	29.832800	w/o ITC	30.800480

STATE		Year 2005	Effective Tax Rate		Effective Tax Rate W/O ITC
Pretax Book Income		87,809,491			
Permanent Differences					
Exempt Interest	-				
Nontaxable Dividends	-				
Nondeductible Meals	68,518				
Various permanent differences	177,904				
Life Insurance	-				
AFUDC	487,148				
Preferred Dividends paid	-				
Expenses associated w/ tax exempt income	-				
Equity in subsidiary	(1,114,162)				
	-				
Total Permanent Differences		(380,592)			
Taxable Income		87,428,899			
Apportionment Factor		1.00000			
Taxable Income		87,428,899			
ESOP Dividends		-			
Manufacturing Deduction		(1,000,000)			
Taxable Income		86,428,899			
Effective Tax Rate		0.070000			
Tax (Kentucky)		6,050,023	6.889900		
Deferred Tax Adjustments (203(e)) state		(52,000)	(0.059200)		
Deferred Tax Adjustments - Adj to Actual		-	-		
Deferred Tax Adjustments - Tax Rate Change		347,403	0.395600		
Reserve					
Adjusted State Tax		6,345,426	7.226300		7.226360
Total Taxes per Calculation		32,541,465	37.059100	w/o ITC	38.026840
Total Taxes per Acufile		32,541,466	37.059200	w/o ITC	38.026830
Difference		(1)	(0.000100)		0.000010

FEDERAL TAX COMPARISON OF ACTUAL WITH ACCRUAL
LG&E ENERGY CORP. AND SUBS
YEAR ENDED DECE 31, 2004

ITEMS ARE INPUT AS INCOME(EXPENSE) REGARDLESS OF M-3 CATEGORY

		2004 LG&E Books	Electric Total	Gas & Other	2004 KU Books	Electric Production	Other	
	Ratio		Electric Only 67.46%	Electric & Gas 56.40%	Ratio	ctric Only 56.56%		
Net Operating Income		259,306,000	230,994,900	28,311,100	178,121,000	178,121,000	0	
Taxes		0	0	0	0	0	0	
Other Income Less Deduction		(92,000)	0	(92,000)	(132,000)	(132,000)	0	
Interest		(34,653,000)	(28,875,173)	(5,777,827)	(30,883,000)	(30,883,000)	0	
Pretax Income		224,561,000	202,119,728	22,441,272	147,106,000	147,106,000	0	
			Electric Production	Other (includes Gas & Elec)				
Allocation of Pretax Income		224,561,000	136,354,841	88,206,159	147,106,000	83,199,018	63,906,982	
AFUDC	P				0	0	0	Direct
Dividends Paid Deduction	P	(430,147)	(242,617)	(187,530)	(247,000)	(139,696)	(107,304)	Allocation PC
Equity in Subsidiary Earnings	P			0	(2,047,370)	0	(2,047,370)	Direct
Life Insurance	P			0	(2,000,000)	(1,800,000)	(200,000)	Allocation PC
Non-Deductible - M&E	P	168,879	95,253	73,626	121,088	68,484	52,604	Allocation PC
Non-Deductible - Other	P	0	0	0	0	0	0	Allocation PC
Non-Deductible Interest Expense/I	P	1,358,593	766,290	592,303			0	Allocation PC
Non-Deductible Lobbying & Politic	P	315,724	178,078	137,646	397,050	224,560	172,490	Allocation PC
Non-Deductible Penalties	P	0	0	0	0	0	0	Allocation PC
Total Permanent Differences		1,413,049	797,005	616,044	(3,776,232)	(1,646,652)	(2,129,580)	
AFUDC	T		0	0	0	0	0	Direct
Amortization of Deferred Expense	T	0	0	0	(14,153)	(8,005)	(6,148)	Allocation PC
Amortization of Flowage Rights	T		0	0	(13,189)	(13,189)	0	Direct
Bad Debt Reserve	T	0	0	0	0	0	0	Allocation PC
Book Basis Emission Allowences	T	0	0	0	0	0	0	Direct
Book Depreciation	T	126,073,000	71,750,152	54,322,848	118,265,000	60,456,144	57,808,856	Direct
CAFC	T	0	0	0	0	0	0	Direct
Capitalized Gas Inventory Costs	T		0	0			0	Direct
CIAC	T	3,000,000	0	3,000,000	2,000,000	0	2,000,000	Direct
Contingent Liabilities	T		0	0			0	Direct
Cost of Removal	T	(6,000,000)	(3,384,183)	[illegible]	(5,000,000)	(2,827,859)	(2,172,141)	Direct
Cummulative Effect of Accouting C	T			0			0	Direct
[redacted]								
Earnings Sharing Mechanism	T	2,118,253	2,118,253	0	3,115,478	3,115,478	0	Direct
Environmental Cost Recovery	T	0	0	0	0	0	0	Direct
Equity in Subsidiary	T		0	0	0	0	0	Direct
FAS 106 Post Retirement Benefits	T	1,855,144	1,251,525	603,619	3,505,496	1,982,610	1,522,886	Allocation PC
FAS 112 Post Employment Benefit	T	141,096	95,187	45,909	145,620	82,359	63,261	Allocation PC
FAS 133 Timing	T		0	0	0	0	0	Allocation PC
FASB 143	T			0			0	Direct
FICA Accrual Adjustment	T			0	0	0	0	Allocation PC
Fuel Adjustment Clause Refund	T			0	0	0	0	Direct
Gas Franchise Fee	T	0	0	0			0	Direct
Interest Capitalized	T	6,022,000	3,396,601	2,625,399	6,981,000	3,948,257	3,032,743	Direct
Insurance Reimbursement/Alstom	T			0			0	Direct
IRS Rollover-Amort.Cap Legal Co	T	0	0	0			0	Direct
Legal Expense Reserve	T		0	0			0	Direct
Line Pack - IRS Audit	T			0			0	Direct
Long Term Incentive	T		0	0		0	0	Allocation PC
Loss on Reacquired Debt - Amorti	T	1,151,892	777,094	374,798	(1,189,616)	(672,813)	(516,803)	Allocation PC
Mark to Market Adjustment	T	0	0	0	0	0	0	Allocation PC
Medical Plan	T	0		0	0		0	Allocation PC
Merger Surcredit	T			0			0	Direct
Merger Expenses Capitalized for T	T		0	0	0	0	0	Direct
Non-Deductible Pensions	T	5,475,936	3,694,198	1,781,738	3,103,672	1,755,350	1,348,322	Allocation PC
Non-Qualified Thrift Plan (Officers	T	6,257	4,221	2,036	50,000	28,279	21,721	Allocation PC
OMU Excess Construction Fund	T			0	0	0	0	Direct
Over/Under Collections-Va	T			0			0	Direct
Over Under Un/Ins	T			0	0	0	0	Allocation PC
Performance Incentive	T			0		0	0	Allocation PC
Pitcairn Contract	T			0	58,929	58,929	0	Direct
Prepaid Insurance/Expenses	T	0	0	0			0	Direct
Prepaid Transmission Fees	T	(22,296)	0	(22,296)			0	Direct
Public Liability Reserve	T	0	0	0			0	Direct
Purchased Gas Adjustment	T	0	0	0			0	Direct
RAR Interest Reserve	T	0	0	0	0	0	0	Direct
Regulatory Expense	T	1,382,148	932,430	449,718	1,069,896	605,103	464,793	Allocation PC

FEDERAL TAX COMPARISON OF ACTUAL WITH ACCRUAL
LG&E ENERGY CORP SUBS
YEAR ENDED DECF 1, 2004

		Ratio	Electric Only	Electric & Gas	Ratio	.nc Only			
			67.48%	56.40%		56.56%			
ITEMS ARE INPUT AS INCOME(EXPENSE) REGARDLESS OF M-3 CATEGORY									
		2004 LG&E Books	Electric Total	Gas & Other	2004 KU Books	Electric Production	Other		
Repair Allowance	T			0	(3,000,000)	0	(3,000,000)	Direct	
SERP	T			0		0	0	Allocation PC	
Short Term Incentive	T			0		0	0	Allocation PC	
Site Assessment Cost (Environmei	T	0	0	0			0	Direct	
[redacted]									May need to be direct (production income * state tax rate
									May need to be direct (production income * state tax rate
									May need to be direct (production income * state tax rate
Storm Damages	T		0	0	0	0	0	Direct	
Supplemental Retirement	T			0		0	0	Allocation PC	
Tax Depreciation	T	(131,000,000)	(85,150,000)	(45,850,000)	(120,000,000)	(84,000,000)	(36,000,000)	Direct	
Tax Gain/(Loss) on Disposal of As	T			0			0	Direct	
Unamortized Loss on Bonds (loss	T	0	0	0		0	0	Allocation PC	
Unclaimed Checks	T	0	0	0		0	0	Direct	
Vacation/Sick Pay	T	0	0	0		0	0	Allocation PC	
VDT Powergen Merger	T	30,134,760	20,329,636	9,805,124	11,753,520	6,647,460	5,106,060	Allocation PC	
[redacted]									
Workers Compensation	T	0	0	0	0	0	0	Allocation PC	
Total Temporary Differences		18,338,190	973,375	17,364,815	8,831,653	(15,628,760)	24,460,413		
OTHER									
Dividends Deduction/Rounding...........		0	0	0	0	0	0	Allocation PC	
Total Adjustments		19,751,239	1,770,380	17,980,859	5,055,421	(17,275,412)	22,330,833		
Federal Taxable Income before Productio		244,312,239	138,125,221	106,187,018	152,161,421	65,923,605	86,237,816		
Production Credit (3%)		4,143,757	4,143,757	0	1,977,708	1,977,708	0		
Federal Taxable Income		248,455,996	142,268,977	106,187,018	154,139,129	67,901,313	86,237,816		
Production Credit Tax Effect		1,450,315			692,198				
Effective Rate Impact		0.65%			0.47%				

$4m

$2m

Attachment to KIUC Question No. 1
Page 165 of 16
Blak

Blake Exhibit 1
Reference Schedule 1.74
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Calculation of Revenue Gross Up Factor
(Based on Law in Effect June 30, 2005)

1. Assume pre-tax income of	$ 100.000000
2. Bad Debt at .16%	0.160000
3. PSC Assessment at .167%	0.167000
4. Taxable income for State income tax	99.673000
5. State income tax at 7.00%	6.977110
6. Taxable income for Federal income tax	92.695890
7. Federal income tax at 35%	32.443563
8. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 5 + Line 7)	39.747673
9. Assume pre-tax income of	$ 100.000000
10. Gross Up Revenue Factor	60.252327

NOTE: Bad debt percent is percent of net charge-offs to revenue for the 12 months ended June 30, 2005.

Kentucky Utilities
Reserve for Doubtful Accounts Analysis

Billed Revenues from Ultimate Consumer		Charge-offs		Recoveries		Net Charge-	Net Charge-offs as a percent of Revenues	
Month	Amount	Month	Amount	Month	Amount	offs	Monthly Avg	12 Mo. Avg
Jan 2004	73,848,843	May 2004	264,865	Jul 2004	87,860	177,005	0.24%	
12 Mth Tot	741,422,460		1,987,441		788,096	1,199,345		0.16%
Feb 2004	71,791,436	Jun 2004	252,535	Aug 2004	47,765	204,770	0.29%	
12 Mth Tot	743,864,467		2,060,863		782,347	1,278,516		0.17%
Mar 2004	59,477,618	Jul 2004	62,784	Sep 2004	91,502	(28,718)	-0.05%	
12 Mth Tot	741,968,666		1,755,559		829,030	926,528		0.12%
Apr 2004	60,071,108	Aug 2004	471,455	Oct 2004	23,911	447,545	0.75%	
12 Mth Tot	748,269,583		2,008,336		800,717	1,207,618		0.16%
May 2004	57,336,416	Sep 2004	171,013	Nov 2004	47,778	123,235	0.21%	
12 Mth Tot	752,554,952		2,064,674		800,221	1,264,453		0.17%
Jun 2004	65,024,722	Oct 2004	126,473	Dec 2004	66,809	59,664	0.09%	
12 Mth Tot	758,536,843		2,081,189		764,530	1,316,659		0.17%
Jul 2004	68,949,981	Nov 2004	124,748	Jan 2005	50,333	74,415	0.11%	
12 Mth Tot	760,515,769		2,048,588		761,702	1,286,886		0.17%
Aug 2004	70,071,914	Dec 2004	156,190	Feb 2005	65,983	90,207	0.13%	
12 Mth Tot	768,410,720		2,061,221		760,772	1,300,450		0.17%
Sep 2004	69,845,696	Jan 2005	126,428	Mar 2005	54,555	71,873	0.10%	
12 Mth Tot	772,056,295		2,021,808		708,925	1,312,883		0.17%
Oct 2004	63,062,457	Feb 2005	115,883	Apr 2005	47,797	68,086	0.11%	
12 Mth Tot	777,848,452		2,024,479		674,541	1,349,938		0.17%
Nov 2004	62,709,386	Mar 2005	116,043	May 2005	49,605	66,438	0.11%	
12 Mth Tot	787,970,100		2,063,337		679,574	1,383,762		0.18%
Dec 2004	74,551,478	Apr 2005	69,188	Jun 2005	54,979	14,209	0.02%	
12 Mth Tot	796,191,042		2,057,605		688,877	1,368,728		0.17%
Jan 2005	81,668,804	May 2005	171,329	Jul 2005	40,066	131,264	0.16%	
12 Mth Tot	804,011,003		1,964,069		641,083	1,322,987		0.16%
Feb 2005	80,202,036	Jun 2005	214,791	Aug 2005	55,542	159,249	0.20%	
12 Mth Tot	812,921,613		1,926,325		648,860	1,277,465		0.157%

Kentucky Utilities
Reserve for Doubtful Accounts Analysis

Billed Revenues from Ultimate Consumer		Reserve %	Computed Reserve	Actual Reserve	Over (under)	Adjustment Expense	
Month	Amount	from Page 1	Balance	Balance	Accrued	(Recovery)	
May 2004	57,336,416						
4 Mth Tot	248,126,565	0.16%	401,376	520,000	118,624		
Jun 2004	65,024,722						
4 Mth Tot	241,859,861	0.17%	415,696	520,000	104,304		
Jul 2004	68,949,981						
4 Mth Tot	251,382,227	0.12%	313,912	330,000	16,088		
Aug 2004	70,071,914						
4 Mth Tot	261,383,033	0.16%	421,841	330,000	(91,841)		
Sep 2004	69,845,696						
4 Mth Tot	273,892,313	0.17%	460,197	330,000	(130,197)		
Oct 2004	63,062,457						
4 Mth Tot	271,930,048	0.17%	472,013	470,000	(2,013)		
Nov 2004	62,709,386						
4 Mth Tot	265,689,453	0.17%	449,579	470,000	20,421		
Dec 2004	74,551,478						
4 Mth Tot	270,169,017	0.17%	457,231	470,000	12,769		
Jan 2005	81,668,804						
4 Mth Tot	281,992,125	0.17%	479,528	470,000	(9,528)		
Feb 2005	80,202,036						
4 Mth Tot	299,131,704	0.17%	519,136	486,199	(32,937)	16199	38384
Mar 2005	76,675,110						
4 Mth Tot	313,097,428	0.18%	549,834	538,073	(11,761)	51874	38442
Apr 2005	67,701,907						
4 Mth Tot	306,247,857	0.17%	526,469	531,694	5,225	-6379	38472
May 2005	59,911,004						
4 Mth Tot	284,490,057	0.16%	468,124	454,340	(13,784)	(77,354)	May-2005
Jun 2005	73,358,347						
4 Mth Tot	277,646,368	0.16%	436,307	422,512	(13,795)	(31,828)	Jun-2005

Source: Notices 103500798 and 103500801 PSC Notice of Tax Due

Tax Due	LGE Electric	KU (Only)
Period 7/1/05-6/30/06	$ 1,657,399.03	$ 1,406,346.83
Gross Intrastate Receipts	$ 992,454,510.00	$ 842,123,849.00
Percentage	0.167%	0.167%

KENTUCKY UTILITIES COMPANY

CASE NO. 2005-00351

Response to the First Set of Data Requests of KIUC Dated October 21, 2005

Question No. 11

Responding Witness: Kent W. Blake

Q-11. Please refer to Blake Exhibit 1. Please explain why there are no adjustments to remove FAC revenues and expenses from operating income in the same manner that ECR revenues and expenses and DSM revenues and expenses were removed on lines 4 and 5 through adjustments 1.11 and 1.12, respectively.

A-11. The Company did remove FAC revenues and expenses from operating income through the adjustment included as Reference Schedule 1.15 of Blake Exhibit 1.

KENTUCKY UTILITIES COMPANY

CASE NO. 2005-00351

Response to the First Set of Data Requests of KIUC Dated October 21, 2005

Question No. 12

Responding Witnesses: Kent W. Blake / Valerie L. Scott

Q-12. Refer to Blake Exhibit 1 Schedules 1.11 and 1.13. Please provide the general ledger revenue amounts by account for the ECR revenues and reconcile the revenues on each of these schedules to the general ledger amounts.

A-12. Please see the attached.

KENTUCKY UTILITIES

Adjustment to Eliminate Environmental Surcharge Revenues and Expenses
For the Twelve Months Ended June 30, 2005

Expense Month	Revenues All Plans		Expenses Post '94 Plan	Expenses Roll-In	Net of Roll-In Expenses Post '94 Plan	Net
Jul-04	$ 1,576,134	**Page 2**	$ 458,578	$ (6,197)	$ 452,381	
Aug-04	1,282,367	**Page 2**	417,126	(6,197)	410,929	
Sep-04	1,115,530	**Page 2**	436,502	(6,197)	430,305	
Oct-04	1,099,282	**Page 2**	412,893	(6,197)	406,696	
Nov-04	1,676,595	**Page 2**	258,327	(6,197)	252,130	
Dec-04	1,958,572	**Page 2**	4,627,568	(6,197)	4,621,371	
Jan-05	2,279,163	**Page 2**	727,540	(6,197)	721,343	
Feb-05	4,312,170	**Page 2**	683,523	(6,197)	677,326	
Mar-05	1,381,557	**Page 2**	765,330	(6,197)	759,133	
Apr-05	1,226,103	**Page 2**	671,457	(6,197)	665,260	
May-05	1,665,912	**Page 2**	(337,492)	(6,197)	(343,689)	
Jun-05	2,204,030	**Page 2**	1,206,567	(6,197)	1,200,370	
			10,327,919	(74,364)	10,253,555	
Jurisdictional %					86.763%	
Total	$ 21,777,415	**Page 2**			$ 8,896,292	$ 12,881,123
Adjustment	$ (21,777,415)				$ (8,896,292)	$ (12,881,123)

ECR BILLED REVENUES
Reference Schedule 1.11

Billed ECR Revenues

KU

Account		Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Total
440010	Residential	598,803.35	465,430.57	393,156.04	347,869.77	537,279.42	771,339.23							3,113,878.38
442025	Large Commercial	419,392.55	344,178.15	299,727.07	301,921.32	456,051.87	481,601.29							2,302,872.25
442035	Industrial	379,687.13	322,841.66	284,083.94	308,124.13	467,981.58	480,947.95							2,243,666.39
442065	Mine Power	38,441.74	33,377.32	28,934.16	32,247.91	54,457.42	58,718.01							246,176.56
444010	Street Lighting	14,944.96	12,431.85	10,920.26	11,910.49	18,669.85	18,747.56							87,624.97
445010	Public Authority	118,397.55	98,678.02	94,022.24	92,009.96	134,295.91	138,590.41							675,994.09
445030	Municipal Pumping	6,466.67	5,429.14	4,686.06	5,198.32	7,858.71	8,627.70							38,266.60
440111	Residential							995,095.25	1,851,733.72	552,317.86	434,426.26	548,113.00	734,016.04	5,115,702.13
442211	Large Commercial							545,755.03	1,037,610.37	326,781.11	318,965.59	456,796.12	590,196.17	3,276,104.39
442311	Industrial							492,865.92	946,680.62	347,708.19	320,831.60	444,066.27	608,336.68	3,160,489.28
442611	Mine Power							62,817.35	125,782.60	43,233.70	40,178.23	57,770.43	66,203.41	395,985.72
444111	Street Lighting							19,878.31	38,948.29	12,372.94	12,173.00	18,046.22	20,259.91	121,678.67
445111	Public Authority							153,412.68	293,761.77	93,526.80	94,131.88	133,390.57	175,587.14	943,810.84
445311	Municipal Pumping							9,338.50	17,652.16	5,616.68	5,396.81	7,729.61	9,430.88	55,164.64
		1,576,133.95	1,282,366.71	1,115,529.77	1,099,281.90	1,676,594.76	1,958,572.15	2,279,163.04	4,312,169.53	1,381,557.28	1,226,103.37	1,665,912.22	2,204,030.23	21,777,414.91
		Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1	Page 1

Blake Exhibit 1
Reference Schedule 1.13
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

To Eliminate ECR and FAC Accruals
For the Twelve Months Ended June 30, 2005

1. ECR Accrued Revenue in Account 449	$	2,494,082	**Page 4**
2. FAC Accrued Revenue in Account 449		(488,683)	**Page 4**
3. ECR Accrued Revenue in Accounts 440-445		(773,713)	**Page 5**
4. FAC Accrued Revenue in Accounts 440-445		20,751,078	**Page 6**
5. Total Accrued Revenues	$	21,982,764	
6. Less ODP FAC Revenue included in Line 2		(545,672)	**Page 4**
7. Kentucky Jurisdictional Accrued Revenues	$	22,528,436	
8. Adjustment	$	(22,528,436)	

ECR AND FAC ACCRUED REVENUE IN ACCOUNT 449
Reference Schedule 1.13

Rate Refund

KU

Account		Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Total	
449105	J505	457,017.00	754,654.00	358,737.00	886,477.00	298,465.00	(261,268.00)	-	-	-	-	-	-	2,494,082.00	Page 3
449105	J509	(16,154.00)	212,624.00	93,031.00	469,293.00	424,568.00	(1,126,373.00)							56,989.00	Page 3
449105	J579	-	-	(175,237.00)	-	-	(370,435.00)							(545,672.00)	Page 3
		440,863.00	967,278.00	276,531.00	1,355,770.00	723,033.00	(1,758,076.00)	-	-	-	-	-	-	2,005,399.00	

ECR ACCRUED REVENUE IN ACCOUNTS 440-445
Reference Schedule 1.13

Accrued ECR Revenues

KU

Account		Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Total
440111	*Residential*	-	-	-	-	-	-	(93,781.00)						(93,781.00)
442211	Commercial	-	-	-	-	-	-	(51,434.00)						(51,434.00)
442311	Industrial	-	-	-	-	-	-	(46,450.00)						(46,450.00)
442611	Mine Power	-	-	-	-	-	-	(5,920.00)						(5,920.00)
444111	Street Lighting	-	-	-	-	-	-	(1,873.00)						(1,873.00)
445111	Public Authority	-	-	-	-	-	-	(14,458.00)						(14,458.00)
445311	Municipal Pumping	-	-	-	-	-	-	(880.00)						(880.00)
440111	Residential	-	-	-	-	-	-	-	(228,218.00)	(221,324.00)	(328,663.00)	534,137.74	(16,875.89)	(260,943.15)
442211	Commercial	-	-	-	-	-	-	-	(126,932.00)	(129,547.00)	(201,988.00)	493,524.51	(80,242.68)	(45,185.17)
442311	Industrial	-	-	-	-	-	-	-	(115,402.00)	(130,358.00)	(206,256.00)	390,630.73	(138,715.50)	(200,100.77)
442611	Mine Power	-	-	-	-	-	-	-	(15,119.00)	(15,675.00)	(24,639.00)	46,421.23	(18,787.38)	(27,799.15)
444111	Street Lighting	-	-	-	-	-	-	-	(4,716.00)	(4,291.00)	(7,008.00)	30,760.15	(479.50)	14,265.65
445111	Public Authority	-	-	-	-	-	-	-	(35,848.00)	(33,099.00)	(54,559.00)	116,245.26	(29,527.09)	(36,787.83)
445311	Municipal Pumping	-	-	-	-	-	-	-	(2,164.00)	(2,221.00)	(3,494.00)	7,406.23	(1,894.18)	(2,366.95)
		-	-	-	-	-	-	(214,796.00)	(528,399.00)	(536,515.00)	(826,607.00)	1,619,125.85	(286,522.22)	(773,713.37)

FAC ACCRUED REVENUE IN ACCOUNTS 440-445
Reference Schedule 1.13

Accrued FAC Revenues

KU

Account		Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Total
449105								-	-	-	3,500,000.00	3,200,000.00	355,812.02	7,055,812.02
440104	Residential	-	-	-	-	-	-	2,121,000.00						2,121,000.00
442204	Commercial	-	-	-	-	-	-	1,181,000.00						1,181,000.00
442304	Industrial	-	-	-	-	-	-	1,433,000.00						1,433,000.00
442604	Mine Power	-	-	-	-	-	-	160,000.00						160,000.00
444104	Street Lighting	-	-	-	-	-	-	18,000.00						18,000.00
445104	Public Authority	-	-	-	-	-	-	386,000.00						386,000.00
445304	Municipal Pumping	-	-	-	-	-	-	22,000.00						22,000.00
440104	Residential	-	-	-	-	-	-	-	(136,343.12)	(357,930.00)	621,174.00	456,061.00	1,795,736.00	2,378,697.88
442204	Commercial	-	-	-	-	-	-	-	(75,603.20)	(198,474.00)	463,493.00	391,558.00	1,514,001.00	2,094,974.80
442304	Industrial	-	-	-	-	-	-	-	(94,384.23)	(247,779.00)	640,546.00	525,578.00	2,020,026.00	2,843,986.77
442604	Mine Power	-	-	-	-	-	-	-	(11,063.50)	(29,044.00)	69,203.00	58,621.00	193,822.00	281,538.50
444104	Street Lighting	-	-	-	-	-	-	-	(1,042.88)	(2,738.00)	5,758.00	4,648.00	14,643.00	21,268.12
445104	Public Authority	-	-	-	-	-	-	-	(24,901.70)	(65,372.00)	159,201.00	130,197.00	517,436.00	716,560.30
445304	Municipal Pumping	-	-	-	-	-	-	-	(1,395.39)	(3,663.00)	8,625.00	7,337.00	26,336.00	37,239.61
		-	-	-	-	-	-	5,321,000.00	(344,734.02)	(905,000.00)	5,468,000.00	4,774,000.00	6,437,812.02	20,751,078.00