LG&E ENERGY

LG&E Energy LLC
220 West Main Street (40202)
P.O. Box 32030
Louisville, Kentucky 40232

June 18, 2004

Elizabeth O'Donnell, Executive Director
Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601

Re: TARIFF FILING OF KENTUCKY UTILITIES COMPANY TO REVISE RATES FOR SMALL POWER PRODUCTION AND COGENERATION – CASE NO. 2004-00200

Dear Ms. O'Donnell:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Kentucky Utilities Company to the Information Requested in Appendix A of the Commission's Order Dated June 3, 2004, in the above-referenced matter.

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

Sincerely,

John Wolfram

John Wolfram
Manager, Regulatory Affairs

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

TARIFF FILING OF KENTUCKY UTILITIES	)	
COMPANY TO REVISE RATES FOR SMALL	)	CASE NO. 2004-00200
POWER PRODUCTION AND COGENERATION	)	

RESPONSE TO
INFORMATION REQUESTED IN
APPENDIX A
TO AN ORDER OF THE
PUBLIC SERVICE COMMISSION
DATED JUNE 3, 2004

FILED: JUNE 18, 2004

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00200
Response to Information Requested in Appendix A to an Order of the Public Service Commission Dated June 3, 2004

Question No. 1

Responding Witness: B. Keith Yocum

Q1. Refer to Attachments 1 and 2 of KU's May 14, 2004 filing. Attachment 1 lists proposed avoided cost rates for different transaction quantities during different time periods. Attachment 2 shows planned generation additions and the projected per-unit capacity costs and fuel costs of the different additions.

a. Provide a narrative description of how the per-unit capacity costs and energy costs shown in Attachment 2 were developed, along with the workpapers, calculations, spreadsheets, etc. that produce the cost levels shown therein.

b. Provide a narrative description of how the avoided cost rates shown in Attachment 1 were derived. The description should fully explain how the per-unit costs in Attachment 2 are reflected in the avoided cost rates in Attachment 1. Include the workpapers, calculations, spreadsheets, etc. that show the derivation of these avoided cost rates.

A-1. a. Trimble Co. CT 7-10

- Capacity costs were developed using costs identified in Case No. 2002-00381 (CCN for TC 7-10) and expected unit net summer capacity.

  Capacity Cost = \$227,392,000 / 155,000 kW = \$367/kW

- Fuel cost was obtained from the Prosym hourly production model output.

  Fuel Cost = Avg. Heat Rate (btu/kWh) x Avg. Fuel Cost (cent/mmbtu)
  = (11,004 btu/kWh x 547.5 cent/mmbtu) / 1,000,000
  = 6.02 cent/kWh

Trimble County 2

- The capacity cost was based on 75% of the most recent capital costs provided by Cummins & Barnard, Inc. (January 2004) and the Company's expected net summer capacity from the unit. The Cummins

- & Barnard estimate has been slightly modified to reflect updated capital requirements from 2003 to 2006.

  Capacity Cost = \$769,955,625 / 549,000 kW = \$1,402/kW

- The fuel cost was determined using its anticipated heat rate and coal prices for 2010.

  Fuel Cost = Heat Rate (btu/kWh) x Fuel Cost (cent/mmbtu)
  = (8,703 btu/kWh x 132.8 cent/mmbtu) / 1,000,000
  = 1.16 cent/kWh

Greenfield CT

- The capacity cost was taken from KU/LG&E's 2002 IRP (Case No. 2002-00367 Volume III Section VIII. Supply Side Analysis) for a Simple Cycle GE 7FA CT and escalated to 2013 at a rate of 2.3%.

  Capacity Cost = \$425/kW x 1.023(2013-2002) = \$546/kW

- The fuel cost was determined using the heat rate also identified in the 2002 IRP and estimated 2013 gas prices.

  Fuel Cost = Heat Rate (btu/kWh) x Fuel Cost (cent/mmbtu)
  = (11,500 btu/kWh x 631.1 cent/mmbtu) / 1,000,000
  = 7.26 cent/kWh

b. The avoided cost rates shown in Attachment 1 are taken from Prosym hourly production model results. Avoided costs are determined via Prosym by looking at the last specified increments of load (100 MW in this case) and the cost of serving that load. Model results consist of fuel, O&M, and emission costs to serve the specified load - or costs avoided in not serving the load. Avoided fuel costs relating to Trimble Co. CT 7-10 will be included in the rates shown in Attachment 1 for all hours where their generation is in the specified MW increments (i.e. the last 100, 200, or 300 MW of power necessary to meet load requirements). A capacity component is not included in the costs identified in Attachment 1.

Attachment 1

2004 Avoided Energy Cost Filing
(cents/kWh)

Year: 2004

Decremental MW Transaction	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
100	3.124	1.922	1.802	1.987
200	2.966	1.859	1.710	1.890
300	2.556	1.674	1.562	1.704

Year: 2005

Decremental MW Transaction	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
100	3.121	1.795	1.887	2.038
200	2.863	1.980	1.769	1.935
300	2.586	1.684	1.624	1.756

Year: 2006

Decremental MW Transaction	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
100	3.472	1.910	1.863	2.076
200	3.259	1.974	1.716	1.943
300	2.848	1.813	1.638	1.813

Year: 2007

Decremental MW Transaction	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
100	3.837	2.225	2.048	2.296
200	3.502	1.936	1.904	2.112
300	3.102	1.745	1.768	1.936

Year: 2008

Decremental MW Transaction	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
100	3.918	2.277	2.140	2.385
200	3.761	2.152	2.021	2.260
300	3.347	1.990	1.859	2.066

Year: 2009

Decremental MW Transaction	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
100	4.342	2.947	2.499	2.790
200	4.089	2.750	2.356	2.626
300	3.690	2.304	2.107	2.336

Attachment 2

2004 Avoided Energy Cost Filing

Plans for and Cost of Additional Capacity

Year	Unit Added	Summer Rating (MW)	Unit Type	Capacity Cost ($/kW)	Fuel Cost (cent/kWh)
2004	Trimble Co CT 7	155	Combustion Turbine	367	6.02
	Trimble Co CT 8	155	Combustion Turbine	367	6.02
	Trimble Co CT 9	155	Combustion Turbine	367	6.02
	Trimble Co CT 10	155	Combustion Turbine	367	6.02
2005					
2006					
2007					
2008					
2009					
2010	Baseload Unit	549	Baseload	1402	1.16
2011					
2012					
2013	Greenfield CT 1	148	Combustion Turbine	546	7.26

PeriodNam [v3]	SummerPk	WinterPk	OffPeak

2004

Avoided Cost By Period For Total System

Seq	Resource	Period tota	1	2	3
1	VIRTUAL PURCH 1				
	(GWh)	878.4	114.4	97.5	666.5
	(000 $)	17457.08	3574.03	1874.07	12008.98
	($/MWh)	19.87	31.24	19.22	18.02
2	VIRTUAL PURCH 2				
	(GWh)	1756.8	228.8	195	1333
	(000 $)	33198.39	6785.91	3624.33	22788.16
	($/MWh)	18.9	29.66	18.59	17.1
3	VIRTUAL PURCH 3				
	(GWh)	2635.2	343.2	292.5	1999.5
	(000 $)	44900.66	8772.57	4895.19	31232.89
	($/MWh)	17.04	25.56	16.74	15.62

2005

Avoided Cost By Period For Total System

Seq	Resource	Period tota	1	2	3
1	VIRTUAL PURCH 1				
	(GWh)	876	114.4	94.5	667.1
	(000 $)	17852.66	3570.7	1695.89	12586.06
	($/MWh)	20.38	31.21	17.95	18.87
2	VIRTUAL PURCH 2				
	(GWh)	1752	228.8	189	1334.2
	(000 $)	33895.62	6551.42	3742.68	23601.52
	($/MWh)	19.35	28.63	19.8	17.69
3	VIRTUAL PURCH 3				
	(GWh)	2628	343.2	283.5	2001.3
	(000 $)	46146.84	8875.25	4774.42	32497.16
	($/MWh)	17.56	25.86	16.84	16.24

2006

Avoided Cost By Period For Total System

Seq	Resource	Period tota	1	2	3

1	VIRTUAL PURCH 1				
	(GWh)	876	113.1	94.5	668.4
	(000 $)	18185.14	3926.56	1804.55	12454.03
	($/MWh)	20.76	34.72	19.1	18.63
2	VIRTUAL PURCH 2				
	(GWh)	1752	226.2	189	1336.8
	(000 $)	34047.05	7370.79	3730.51	22945.74
	($/MWh)	19.43	32.59	19.74	17.16
3	VIRTUAL PURCH 3				
	(GWh)	2628	339.3	283.5	2005.2
	(000 $)	47644.34	9664.83	5141.07	32838.44
	($/MWh)	18.13	28.48	18.13	16.38

2007

Avoided Cost By Period For Total System

Seq	Resource	Period tota	1	2	3
1	VIRTUAL PURCH 1				
	(GWh)	876	111.8	96	668.2
	(000 $)	20110.36	4289.23	2135.9	13685.23
	($/MWh)	22.96	38.37	22.25	20.48
2	VIRTUAL PURCH 2				
	(GWh)	1752	223.6	192	1336.4
	(000 $)	36997.31	7830.12	3717.02	25450.18
	($/MWh)	21.12	35.02	19.36	19.04
3	VIRTUAL PURCH 3				
	(GWh)	2628	335.4	288	2004.6
	(000 $)	50870.07	10403.75	5025.19	35441.13
	($/MWh)	19.36	31.02	17.45	17.68

2008

Avoided Cost By Period For Total System

Seq	Resource	Period tota	1	2	3
1	VIRTUAL PURCH 1				
	(GWh)	878.4	113.1	100.5	664.8
	(000 $)	20948.13	4431.77	2288.52	14227.84
	($/MWh)	23.85	39.18	22.77	21.4
2	VIRTUAL PURCH 2				
	(GWh)	1756.8	226.2	201	1329.6
	(000 $)	39709.71	8508.43	4325.73	26875.54
	($/MWh)	22.6	37.61	21.52	20.21

3	VIRTUAL PURCH 3				
	(GWh)	2635.2	339.3	301.5	1994.4
	(000 $)	54440.59	11354.81	6000.37	37085.41
	($/MWh)	20.66	33.47	19.9	18.59

2009

Avoided Cost By Period For Total System

Seq	Resource	Period tota	1	2	3
1	VIRTUAL PURCH 1				
	(GWh)	876	114.4	97.5	664.1
	(000 $)	24439.32	4967.64	2873.05	16598.63
	($/MWh)	27.9	43.42	29.47	24.99
2	VIRTUAL PURCH 2				
	(GWh)	1752	228.8	195	1328.2
	(000 $)	46003.56	9354.79	5362.68	31286.08
	($/MWh)	26.26	40.89	27.5	23.56
3	VIRTUAL PURCH 3				
	(GWh)	2628	343.2	292.5	1992.3
	(000 $)	61384.92	12665.27	6740.46	41979.2
	($/MWh)	23.36	36.9	23.04	21.07