COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
DEC 0 8 2004
PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF A STIPULATION AND SETTLEMENT AGREEMENT RESOLVING STATE REGULATORY MATTERS	)	CASE NO. 2004-00420

STAFF'S NOTICE OF HEARING EXHIBITS

On December 7, 2004, a hearing (which was transcribed by video only) was held at the Commission's offices in the above-captioned case. Attached hereto are the originals of the three exhibits that were introduced into the record of this hearing. These exhibits consist of Applicant's Exhibit 1, which was the notice of publication, and Staff's Exhibits 1 and 2.

cc: Parties of Record (without attachments)

Applicant's Exhibit 1

NOTARIZED PROOF OF PUBLICATION

STATE OF KENTUCKY

COUNTY OF Franklin

Before me, a Notary Public, in and for said County and State, this 30th day of November, 2004, came Rachel McCarty personally known to me, who being duly sworn, states as follows:

That she is Advertising Assistant of the Ky Press Service, Inc., and that the following publications: see attached ran the Legal Notice for Kentucky Power Company, Notice to Customers, Proposed changes to the System Sales Tariff.

Rachel McCarty
Signed

Bonnie F. Howard
Notary Public

My commission expires 9-18-08

KENTUCKY PRESS SERVICE

101 Consumer Lane **Frankfort, KY 40601**
(502) 223-8821 **FAX (502) 875-2624**

Rachel McCarty Advertising Dept.

List of newspapers running the Notice to Kentucky Power Company Customers. Attached tearsheets provide proof of publication:

Ashland Daily Independent
Booneville Sentinel
Grayson Journal-Enquirer
Greenup News
Hazard Herald
Hindman Troublesome Creek Times
Hyden Leslie County News
Inez Mountain Citizen
Jackson Times
Louisa Big Sandy News
Manachester Enterprise
Morehead News
Paintsville Herald
Pikeville Appalachian News-Express
Prestonsburg Floyd County TImes
Salyersville Independent
Sandy Hook Elliott County News
Vanceburg Lewis County Herald
West Liberty Licking Valley Courier
Whitesburg Mountain Eagle

Staff Exhibit 1

Exhibit 4-11
(Page 1 of 2)

REGULATED AEP EAST

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016
With Expanded DSM and Additional Resources

		2002 *	2003	2004	2005	2006	2007	2008	2009
DEMAND									
1 Base Peak Internal Demand		19,577	10,950	11,225	11,455	11,631	11,856	12,031	12,263
2 Expanded DSM Programs		-	(1)	(1)	(1)	(2)	(2)	(2)	(2)
3 Adjusted Peak Internal Demand		19,577	10,949	11,224	11,454	11,629	11,854	12,029	12,261
4 Committed Capacity Sales		20	270	250	250	250	250	250	250
5 Total Peak Demand		19,597	11,219	11,474	11,704	11,879	12,104	12,279	12,511
6 Interruptible Load		622	306	306	306	306	306	306	306
7 Total Peak Demand Excluding Interruptible Load		18,975	10,913	11,168	11,398	11,573	11,798	11,973	12,205
GENERATING CAPABILITY (Seasonal)									
8 Capacity Before Changes		23,438	11,179	11,179	11,179	11,179	11,179	11,179	11,179
9 Capacity Changes									
Additions		-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
10 Capacity After Changes		23,438	11,179	11,179	11,179	11,179	11,179	11,179	11,179
11 Unit Power									
Purchases		-	845	845	845	845	845	845	845
Sales		(705)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
12 Net Capacity		22,733	11,774	11,774	11,774	11,774	11,774	11,774	11,774
13 Purchases									
Committed		16	616	616	616	616	166	166	16
Uncommitted		-	-	150	400	600	1,300	1,500	1,900
14 Total Capability		22,749	12,390	12,540	12,790	12,990	13,240	13,440	13,690
RESERVE MARGIN									
Based on Including Interruptible Load									
15 MW	(14)-(5)	3,152	1,171	1,066	1,086	1,111	1,136	1,161	1,179
16 Percent of Demand	[(15)/(5)]x100	16.1	10.4	9.3	9.3	9.4	9.4	9.5	9.4
Based on Excluding Interruptible Load									
17 MW	(14)-(7)	3,774	1,477	1,372	1,392	1,417	1,442	1,467	1,485
18 Percent of Demand	[(17)/(7)]x100	19.9	13.5	12.3	12.2	12.2	12.2	12.3	12.2

* Based on AEP East 5 Company.

Exhibit 4-11
(Page 2 of 2)

REGULATED AEP EAST

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

With Expanded DSM and Additional Resources

		2010	2011	2012	2013	2014	2015	2016
DEMAND								
1 Base Peak Internal Demand		12,450	12,647	12,802	13,049	13,261	13,476	13,651
2 Expanded DSM Programs		(2)	(2)	(2)	(2)	(2)	(2)	(2)
3 Adjusted Peak Internal Demand		12,448	12,645	12,800	13,047	13,259	13,474	13,649
4 Committed Capacity Sales		250	250	250	250	250	250	250
5 Total Peak Demand		12,698	12,895	13,050	13,297	13,509	13,724	13,899
6 Interruptible Load		306	306	306	306	306	306	306
7 Total Peak Demand Excluding Interruptible Load		12,392	12,589	12,744	12,991	13,203	13,418	13,593
GENERATING CAPABILITY (Seasonal)								
8 Capacity Before Changes		11,179	11,179	11,179	11,179	11,179	11,179	11,179
9 Capacity Changes								
Additions		-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-
10 Capacity After Changes		11,179	11,179	11,179	11,179	11,179	11,179	11,179
11 Unit Power								
Purchases		650	650	650	650	650	650	650
Sales		-	-	-	-	-	-	-
12 Net Capacity		11,829	11,829	11,829	11,829	11,829	11,829	11,829
13 Purchases								
Committed		16	16	16	16	16	16	16
Uncommitted		2,050	2,250	2,450	2,700	2,950	3,200	3,400
14 Total Capability		13,895	14,095	14,295	14,545	14,795	15,045	15,245
RESERVE MARGIN								
Based on Including Interruptible Load								
15 MW	(14)-(5)	1,197	1,200	1,245	1,248	1,286	1,321	1,346
16 Percent of Demand	[(15)/(5)]x100	9.4	9.3	9.5	9.4	9.5	9.6	9.7
Based on Excluding Interruptible Load								
17 MW	(14)-(7)	1,503	1,506	1,551	1,554	1,592	1,627	1,652
18 Percent of Demand	[(17)/(7)]x100	12.1	12.0	12.2	12.0	12.1	12.1	12.2

Exhibit 4-12
(Page 1 of 2)

REGULATED AEP EAST

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002/03 - 2016/17

With Expanded DSM and Additional Resources

		2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
DEMAND									
1 Base Peak Internal Demand		11,438	11,721	11,956	12,133	12,367	12,548	12,788	12,982
2 Expanded DSM Programs		(1)	(2)	(3)	(4)	(4)	(4)	(4)	(4)
3 Adjusted Peak Internal Demand		11,437	11,719	11,953	12,129	12,363	12,544	12,784	12,978
4 Committed Capacity Sales		270	250	250	250	250	250	250	250
5 Total Peak Demand		11,707	11,969	12,203	12,379	12,613	12,794	13,034	13,228
6 Interruptible Load		307	307	307	307	307	307	307	307
7 Total Peak Demand Excluding Interruptible Load		11,400	11,662	11,896	12,072	12,306	12,487	12,727	12,921
GENERATING CAPABILITY (Seasonal)									
8 Capacity Before Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326
9 Capacity Changes									
Additions		-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
10 Capacity After Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326
11 Unit Power									
Purchases		845	845	845	845	845	845	845	650
Sales		(250)	(250)	(250)	(250)	(250)	(250)	(250)	-
12 Net Capacity		11,921	11,921	11,921	11,921	11,921	11,921	11,921	11,976
13 Purchases									
Committed		1,024	1,024	1,024	1,024	1,174	174	24	24
Uncommitted		-	150	400	600	700	1,900	2,350	2,500
14 Total Capability		12,945	13,095	13,345	13,545	13,795	13,995	14,295	14,500
RESERVE MARGIN									
Based on Including Interruptible Load									
15 MW	(14)-(5)	1,238	1,126	1,142	1,166	1,182	1,201	1,261	1,272
16 Percent of Demand	[(15)/(5)]x100	10.6	9.4	9.4	9.4	9.4	9.4	9.7	9.6
Based on Excluding Interruptible Load									
17 MW	(14)-(7)	1,545	1,433	1,449	1,473	1,489	1,508	1,568	1,579
18 Percent of Demand	[(17)/(7)]x100	13.6	12.3	12.2	12.2	12.1	12.1	12.3	12.2

Exhibit 4-12
(Page 2 of 2)

REGULATED AEP EAST

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002/03 - 2016/17

With Expanded DSM and Additional Resources

		2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
DEMAND								
1 Base Peak Internal Demand		13,186	13,345	13,602	13,824	14,047	14,230	14,483
2 Expanded DSM Programs		(4)	(4)	(4)	(4)	(4)	(4)	(4)
3 Adjusted Peak Internal Demand		13,182	13,341	13,598	13,820	14,043	14,226	14,479
4 Committed Capacity Sales		250	250	250	250	250	250	250
5 Total Peak Demand		13,432	13,591	13,848	14,070	14,293	14,476	14,729
6 Interruptible Load		307	307	307	307	307	307	307
7 Total Peak Demand Excluding Interruptible Load		13,125	13,284	13,541	13,763	13,986	14,169	14,422
GENERATING CAPABILITY (Seasonal)								
8 Capacity Before Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326
9 Capacity Changes								
Additions		-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-
10 Capacity After Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326
11 Unit Power								
Purchases		650	650	650	650	650	650	650
Sales		-	-	-	-	-	-	-
12 Net Capacity		11,976	11,976	11,976	11,976	11,976	11,976	11,976
13 Purchases								
Committed		24	24	24	24	24	24	24
Uncommitted		2,700	2,900	3,200	3,450	3,700	3,900	4,150
14 Total Capability		14,700	14,900	15,200	15,450	15,700	15,900	16,150
RESERVE MARGIN								
Based on Including Interruptible Load								
15 MW	(14)-(5)	1,268	1,309	1,352	1,380	1,407	1,424	1,421
16 Percent of Demand	[(15)/(5)]x100	9.4	9.6	9.8	9.8	9.8	9.8	9.6
Based on Excluding Interruptible Load								
17 MW	(14)-(7)	1,575	1,616	1,659	1,687	1,714	1,731	1,728
18 Percent of Demand	[(17)/(7)]x100	12.0	12.2	12.3	12.3	12.3	12.2	12.0

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Staff Exhibit 2

AEP/Kentucky
Capacity Costs with 15% of Rockport
versus without 15% of Rockport
For the five years ending 2009

Information for
March 23 2004
Ky PSC Conf.

Ln No	Description	2005	2006	2007	2008	2009	Total
	KPCo with 15% of Rockport						
1	Pool Capacity Settlement costs	$27,023,810	$24,998,607	$27,182,398	$30,683,302	$31,088,768	$140,976,885
2	Unit Power Capacity costs	$37,326,704	$38,277,958	$39,204,784	$40,149,135	$41,115,395	$196,073,976
3	Subtotal	$64,350,514	$63,276,565	$66,387,182	$70,832,437	$72,204,163	$337,050,861
	KPCo without 15% of Rockport						
4	Pool Capacity Settlement costs	$72,977,529	$70,718,706	$74,089,681	$82,170,739	$84,712,774	$384,669,429
5	Unit Power Capacity costs	$0	$0	$0	$0	$0	$0
6	Subtotal	$72,977,529	$70,718,706	$74,089,681	$82,170,739	$84,712,774	$384,669,429
7	Difference (Ln.6 - Ln.3)	$8,627,015	$7,442,141	$7,702,499	$11,338,302	$12,508,611	$47,618,568
8	Unit Power Bill Cost of Common Equity Rockport Unit No. 1						12.16%

Information for
March 23 2004
Ky PSC Conf.

AEP/Kentucky
Rockport Unit Power Agreement
2003 Costs

Ln No	Description	Rockport Unit No. 1 2003 Costs	Rockport Unit No. 2 2003 Costs	Total Rockport Units 2003 Costs
	KPCo's 15% of Rockport			
1	Unit Power Energy costs	$15,629,201	$18,642,214	$34,271,415
2	Unit Power Capacity costs	$13,949,264	$21,665,891	$35,615,155
3	Subtotal	$29,578,465	$40,308,105	$69,886,570
4	KPCo's 15% Generation of Rockport (KWH)	1,237,571,000	1,459,262,000	2,696,833,000
5	KPCo's Cost of Generation from Rockport per KWH	$0.023900	$0.027622	$0.025914
6	KPCo's Rockport Bus Cost per KWH (Ln.1/Ln.4)	$0.012629	$0.012775	$0.012708
7	Combined Cycle Bus Cost per KWH ($0.04277 fuel +$ 0.00077 variable)	$0.043540	$0.043540	$0.043540
8	Rockport KWH Cost is less then Combined Cycle [(Ln.7/Ln.6) - 1]	244.76%	240.82%	242.62%
9	Rockport Unit Capacity Costs	$13,949,264	$21,665,891	$35,615,155
10	Kilowatts of Capacity	195,000	195,000	390,000
11.	Capacity Cost per Kilowatt (Ln.9/10)	$71.53	$111.11	$91.32
12	Combined Cycle Capacity Cost per KW	$112.35	$112.35	$112.35
13	Rockport KW Cost is less then Combined Cycle [(Ln.12/Ln.11) - 1]	57.06%	1.12%	23.03%