EAST KENTUCKY POWER COOPERATIVE

February 6, 2006

HAND DELIVERED

Ms. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

RECEIVED
FEB 0 6 2006
PUBLIC SERVICE COMMISSION

Re: PSC Case No. 2005-00053

Dear Ms. O'Donnell:

Please find enclosed for filing with the Commission in the above-referenced case an original and seven (7) copies of the responses of East Kentucky Power Cooperative, Inc., to the Commission Staff's Second Data Request, dated January 25, 2006.

Very truly yours,

Charles A. Lile

Charles A. Lile
Senior Corporate Counsel

Enclosures

Cc: Service List

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2005-00053
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED
JANUARY 25, 2006
REQUEST NO. 1
RESPONDING PERSON: David Eames

Request 1 (a): Refer to page 3 of the December 22, 2005 Supplemental Prepared Testimony of David G. Eames ("Eames Testimony") and Exhibit 1 to the Eames Testimony. The testimony states,

> The results of that analysis are attached as Exhibit 1 to this testimony. That analysis shows that a delay in Smith [combustion turbine ("CT")] CTs 9-12 is estimated to result in approximately $11.9 million in higher power production and/or power purchase costs, and $10.9 million in additional costs due to construction schedule delay charges, as detailed in the attached letter from General Electric (Exhibit 2), for a total additional cost of $22.8 million.

The exhibit contains the heading "EKPC Monthly Variable System Cost" and appears to include only $11.9 million, which matches the level identified in the testimony as "higher power production and/or power purchase costs."

a. Is it correct that the analysis in Exhibit 1 to the Eames Testimony shows only the $11.9 million in higher power production and/or power purchase costs resulting from a delay in Smith combustion turbine ("CTs") 9-12?

Response 1 (a): Yes. None of the construction schedule delay charges detailed in the GE letter (Exhibit 2) were included in Exhibit 1.

Request 1 (b): Are the delay costs shown in Exhibit 1 strictly variable costs or do they include any fixed costs?

Response 1 (b): The delay costs shown are only variable costs.

EAST KENTUCKY POWER COOPERATIVE, INC.
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REQUEST NO. 2
RESPONDING PERSON: David Eames

Request 2: The analyses contained in Exhibits 1 and 4 to the Eames Testimony are not the type of long-term present value revenue requirements ("PVRR") analyses typically relied upon by the Commission to evaluate a utility's decisions regarding both the construction and the timing thereof of major plant additions. Provide a 30-year PVRR analysis which reflects all of the cost impacts of (1) proceeding with the installation of Smith CTs 9-12 in 2008, as EKPC proposes, recognizing the transmission limitations described in the Eames Testimony, and (2) delaying the installation of these CTs until 2009, recognizing those same limitations. This analysis should include all relevant cost components, including but not limited to (1) construction costs, (2) financing costs, (3) depreciation expense, and (4) variable cost.

Response 2: The requested long term analysis is included in this filing as Attachment 1. The variable costs in the two cases are assumed to be the same from the point when the last unit comes online in the delay case (October 1, 2009) forward. The variable costs include fuel and O&M costs. The difference in variable costs between the cases was taken from EKPC's December 21, 2005 filing in this case. The financing for the project was assumed to be in 2008 for the Base (With Limits) case, but with half of the financing in 2008, and half in 2009, for the Delay case. Since the units reach commercial operation at different times in the cases, there would be some difference in depreciation.

Attachment 1 shows that with a 3% discount rate, there is a savings of approximately $22 million in favor of the Base (With Limits) case. At a 6% discount rate the savings in the Base (With Limits) case is approximately $13 million.

	Attachment 1													
	PSC Case No. 2005-00053 Second Data Request dated 01/25/06	**Question 2**												
	PV year	2006												
	Discount rate 1	1.03												
	Discount rate 2	1.06												
		year-->	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	Base (With Limits) **Case2**: Generation Carrying Charges (GCC), actual year $		0	0	0	0	30,742,169	30,454,423	30,148,530	29,816,715	29,464,161	29,082,574	28,674,285	28,236,186
	Delay Case **Case 3:** GCC, actual year $		0	0	0	0	15,371,084	31,890,927	31,582,009	31,250,293	30,894,156	30,512,262	30,101,279	29,660,917
	PV Base (With Limits) GCC		0	0	0	0	28,977,442	27,870,111	26,786,579	25,720,160	24,675,771	23,646,794	22,635,746	21,640,685
	PV Delay Case GCC		0	0	0	0	14,488,721	29,184,716	28,060,206	26,956,777	25,873,369	24,809,261	23,762,227	22,732,623
	PV Difference Delay Case GCC		0	0	0	0	14,488,721	-1,314,605	-1,273,627	-1,236,617	-1,197,598	-1,162,467	-1,126,482	-1,091,938
@3%	Total all years Difference in GCC PV		-11,238,530											
	(negative amount signifies that delay case is the more expensive)													
	PV Base (With Limits) GCC		0	0	0	0	27,360,421	25,570,120	23,880,460	22,280,784	20,771,071	19,341,573	17,990,601	16,712,955
	PV Delay Case GCC		0	0	0	0	13,680,210	26,776,237	25,015,909	23,352,037	21,779,161	20,292,397	18,885,915	17,556,251
	PV Difference Delay Case GCC		0	0	0	0	13,680,210	-1,206,116	-1,135,449	-1,071,253	-1,008,090	-950,824	-895,313	-843,296
@6%	Total all years Difference in GCC PV		-3,596,123											
	(negative amount signifies that delay case is the more expensive)													
	Variable cost savings: Base (With Limits), actual year $		0	0	0	0	-6,719,272	-5,135,504	0	0	0	0	0	0
	Variable cost savings: Delay Case, actual year $		0	0	0	0	0	0	0	0	0	0	0	0
	Difference in Variable cost savings: no delay minus delay		0	0	0	0	-6,719,272	-5,135,504	0	0	0	0	0	0
@3%	PV Variable cost savings: Base (With Limits)		0	0	0	0	-5,969,986	-4,429,931	0	0	0	0	0	0
	PV Variable cost savings: Delay Case		0	0	0	0	0	0	0	0	0	0	0	0
	PV Difference in Variable cost savings: Base (With Limits) minus Delay		0	0	0	0	-5,969,986	-4,429,931	0	0	0	0	0	0
	PV Difference in Variable cost savings: total of all years		-10,399,917											
@6%	PV Variable cost savings: Base (With Limits)		0	0	0	0	-5,322,293	-3,837,547	0	0	0	0	0	0
	PV Variable cost savings: Delay Case		0	0	0	0	0	0	0	0	0	0	0	0
	PV Difference in Variable cost savings: Base (With Limits) minus Delay		0	0	0	0	-5,322,293	-3,837,547	0	0	0	0	0	0
	PV Difference in Variable cost savings: Total of all years		-9,159,840											
@3%	**PV Total Savings from GCC & Variable Cost**		**-21,638,447**											
@6%	**PV Total Savings from GCC & Variable Cost**		**-12,755,963**											

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
27,765,682	27,260,700	26,718,649	26,136,676	25,512,189	24,841,560	24,121,935	23,349,428	22,520,149	21,629,950	20,674,167	19,648,391	18,547,438	17,365,346	16,096,671	14,734,673	13,272,612	0
29,188,194	28,680,668	28,135,919	27,551,115	26,923,414	26,249,598	25,526,273	24,749,948	23,916,573	23,021,965	22,061,544	21,030,576	19,924,080	18,736,265	17,461,178	16,092,497	14,623,198	7,194,386
20,660,275	19,693,710	18,739,923	17,797,805	16,866,563	15,944,852	15,031,992	14,126,788	13,228,214	12,335,258	11,446,785	10,561,978	9,679,769	8,798,878	7,918,496	7,037,362	6,154,440	0
21,718,758	20,719,525	19,733,967	18,760,968	17,799,549	16,848,618	15,907,129	14,974,126	14,048,466	13,129,105	12,214,942	11,304,971	10,398,228	9,493,511	8,589,742	7,685,866	6,780,700	3,238,834
-1,058,483	-1,025,815	-994,044	-963,164	-932,986	-903,766	-875,137	-847,338	-820,252	-793,847	-768,157	-742,992	-718,459	-694,633	-671,247	-648,504	-626,260	-3,238,834
15,504,212	14,360,597	13,278,350	12,253,894	11,284,066	10,365,515	9,495,510	8,671,147	7,889,794	7,148,980	6,446,303	5,779,680	5,147,009	4,546,200	3,975,532	3,433,159	2,917,453	0
16,298,535	15,108,618	13,982,690	12,917,038	11,908,252	10,953,040	10,048,322	9,191,250	8,379,023	7,609,059	6,878,894	6,186,257	5,529,034	4,905,103	4,312,536	3,749,530	3,214,326	1,491,885
-794,324	-748,021	-704,340	-663,144	-624,186	-587,525	-552,812	-520,103	-489,229	-460,079	-432,591	-406,577	-382,025	-358,903	-337,004	-316,371	-296,872	-1,491,885
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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EAST KENTUCKY POWER COOPERATIVE, INC.
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INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED
JANUARY 25, 2006
REQUEST NO. 3
RESPONDING PERSON: David Eames

Request 3 (a): Exhibit 3 entitled "EKPC Expected CT Operation" of the Eames Testimony dated December 22, 2005 shows that each of the proposed CTs will operate more than 2000 hours per year. Page 9 of Exhibit 4 of the application shows the Economic analysis of the CTs is based on the CTs operation of a maximum of 2000 hours.

a. How many hours per year is the "GE LMS 100" designed to operate?

Response 3 (a): The LMS100 combustion turbine is designed for a range of service from peaking, up to continuous baseload operation of up to 8760 hours per year if desired, and would only have to be shut down for scheduled maintenance. Scheduled maintenance time will be one to four days per year, depending on what maintenance activities are required in a given year.

The LMS100 is designed with very high simple cycle efficiency. It also has good operating flexibility, including ten minute start capability, high efficiency part load operation, frequent cycling without maintenance penalty and excellent hot day performance. Because of these attributes, the LMS100 has the flexibility to be used in a wide variety of applications in the peaking and intermediate markets.

Request 3 (b): Due to the high price of natural gas and the number of hours that the proposed CTs will be operating, has EKPC performed any feasibility study to determine whether combined cycle combustion turbines are more economical than the proposed CTs? If yes, provide the study. If no, explain in detail why it is not necessary.

Response 3 (b): EKPC has not done a formal study to determine whether combined cycle units would be more economical than the proposed CTs. However, a combined cycle project was proposed to EKPC in RFP No. 2004-01, and was not among the lowest cost proposals. A formal study on combined cycle was not done because combined cycle units are designed and best suited for baseload operation, they are not economical for peaking operation, and would not provide a significant benefit for intermediate operation, based on current gas prices. Combined cycle units are at a disadvantage for the type of peaking service EKPC has historically needed.

EKPC has evaluated and selected the GE LMS 100 units for its projected peaking power needs, but believes that these units offer a unique combination of flexible operating characteristics, lower operational costs, and the potential for conversion to combined cycle operation, should EKPC's needs change. The estimate of operating hours for the proposed CTs was based on a specific natural gas and market price forecast. Since natural gas prices are extremely volatile, the relationship between market prices and gas fired generation costs can vary greatly and, consequently, the actual CT operating hours may vary greatly. However, the proposed CTs capture much of the variable cost benefits of combined cycle units without the negative aspects. The units, as proposed, will offer quick start capability and enhanced reliability and the flexibility to operate economically compared to other gas fired options over a wide range of operating hours.

EKPC has discussed with GE the relative costs and performance issues related to the proposed LMS100 CTs and other gas turbine options. The two options, in addition to the current design, that have been discussed with GE are: (1) to add the steam system necessary to operate the CTs as combined cycle units or (2) to add a steam injection system for NOx control.

The combined cycle option would have a capital cost approximately 22 percent higher than the proposed units, due to the addition of the steam system. The steam system would add considerable complexity to the unit and increase the maintenance requirements of the CT. A typical combined cycle unit may take up to two hours or more to reach its full efficiency due to the time required to heat the steam system. The design layout would have to be altered to provide additional space for the steam system. The combined cycle option does have the benefit of an increase in capacity of about 16 percent and an improvement of the unit heat rate by almost 14 percent.

The steam injection option would have a capital cost approximately 14 percent higher due to the added steam injection system. Steam injection requires a less complex steam system that can be accommodated in the planned footprint of the units. This alternative would provide a 10 percent increase in capacity and a heat rate improvement of just over 12 percent. The cost per kW for the additional steam equipment, based on the resulting increase in capacity, is comparable to combined cycle. The steam injection system would also cause a slow down in the startup of the unit, and would have higher water needs, but would be much less complex and maintenance intensive than a combined cycle steam system. Startup times would be slightly less for the steam injection option than combined cycle. Since the steam injection option can be added to the current design and layout at a later date, it is an option EKPC may wish to explore further with GE for one or more of the proposed units, as its projections of intermediate power needs are more fully analyzed.

The LMS100 CT, as proposed, provides much more operating flexibility than the options above, because it can reach full load in as little as ten minutes, if necessary. These units can be cycled on and off frequently and can ramp up and down much faster than combined cycle units. The ability to bring units on quickly contributes to the reliability of the system and is a benefit of the proposed units. Their much more economical operation, compared to conventional CTs, also helps to offset the high cost of using natural gas for peaking generation. EKPC remains convinced that these units are the best choice for EKPC's identified peaking generation needs, and that combined cycle generation would not be a more economical, or more flexible, alternative.