Case 2003-00266
Filed 1-10-05

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR , INC.	))))))	CASE NO: 2003-00266

REBUTTAL TESTIMONY OF
DAVID S. SINCLAIR
DIRECTOR -- MARKET ANALYSIS AND VALUATION
LG&E ENERGY SERVICES INC.

Filed: January 10, 2005

Q. Please state your name, business address and position.

A. My name is David S. Sinclair. My business address is 220 West Main Street, Louisville Kentucky 40202. I am Director, Market Analysis and Valuation for LG&E Energy Services Inc. on behalf of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). In my position, I supervise two departments, Market Policy and Economic Analysis, consisting of 19 professionals. A complete statement of my education and work experience is attached to my testimony as Appendix A.

Q. What is the purpose of your testimony?

A. I will rebut the criticisms by Dr. McNamara of the Companies' modeling of its production costs, purchase power expense and off-system sales revenues used to assist in the preparation of Mr. Morey's cost-benefit study.

Background on the Companies' Models and Methods

Q. What are the key issues the Commission should consider when it evaluates the models presented by Dr. McNamara and the Companies?

A. Both the Companies and Dr. McNamara are attempting to forecast the Companies' future production costs, purchase power expense, and off-system sales margin. Because of the nature of forecasting, we cannot know *a priori* which forecast is "right." However, by examining the forecasts closely, it is possible to determine which forecast is more reasonable and, thus, is a better forecast. To evaluate which forecast is better, it is important to look at the models utilized by the forecaster, the quality of the assumptions that went into the models, and the reasonableness of the results produced by the combination of the models and the assumptions. The quality of the last step, reviewing the results of the forecast, is further enhanced by the experience and capabilities of the forecaster. A forecast that is deficient in any of these areas (models, assumptions, results, and experience) may be suspect. Conversely, a forecast that was prepared by experienced analysts using great care in the use of models, choice of assumptions, and review of results will likely be reasonable.

Q. Please describe how the Companies developed the forecasts of production costs, purchase power expense, and off-system sales margins utilized in the MISO cost-benefit study.

A. The Companies have a long history of modeling the production costs, purchase power expense and off-system sales margin for their system. In general, to perform this task, the Companies need information regarding the cost of generation for each unit (fuel, variable O&M, emission costs, etc.), a description of the generation capabilities of each unit (capacity, heat rate curve, commitment parameters, emission rates, availability schedules, etc.), a load forecast, the market price of electricity, and the volumetric ability (transfer capability) to access the market.[1] All of this information about the Companies' system is brought together in a software package called PROSYM. PROSYM is the tool utilized to model the Companies' production costs, purchase power expense and off-system sales margin. This model seeks to minimize the cost of serving native load from either the Companies' own generating units or purchases from the market and maximize the margin from off-system sales for each hour of the forecast period.

One thing PROSYM does not do is forecast market prices of electricity. For this, the Companies utilized the software package MIDAS Gold ("MIDAS"). MIDAS, as employed by the Companies, models the power system in the Eastern Interconnect, including representations of approximately 8,000+ generation units in

[1] For a detailed discussion of the models and assumptions used by the Companies see the material in Appendix B to Martyn Gallus' Supplemental Testimony filed September 29, 2004

140 control areas that are aggregated to 26 Regional Transaction Groups. It seeks to minimize the cost of serving load in each control area in the Eastern Interconnect each hour by dispatching the generation units and allowing "trades" to occur between the 26 Regional Transaction Groups subject to seasonal transmission limits. One of the outputs of MIDAS is an hourly forecast of electricity prices for each Transaction Group in the Eastern Interconnect.

Both MIDAS and PROSYM need information regarding the transfer capabilities between regions. MUST was used to analyze and calculate the appropriate transfer capabilities for both models. MUST is a software tool used to calculate transfer capabilities based on a detailed transmission model of the Eastern Interconnect.

Having good software products and models is only part of the forecasting process. For these models to produce reasonable forecasts they need good input data, otherwise it's garbage-in and garbage out. Therefore, the Companies spend significant amounts of time gathering, reviewing, and analyzing data that goes into both MIDAS and PROSYM. Finally, the outputs of both MIDAS and PROSYM were analyzed and checked for reasonableness. In the case of MIDAS, the price forecasts were compared to forward market prices and recent history while the PROSYM results were checked against historical experience.

Q. Have the Companies utilized this modeling approach for purposes other than assisting in Mr. Morey's cost-benefit study?

A. Yes. The PROSYM model has formed the foundation of the analysis used in proceedings before this Commission involving certificates of convenience and necessity for new generating plants, environmental cost recovery for pollution control equipment, integrated resource planning, and the fuel adjustment clause. Furthermore, the PROSYM model was actually "enhanced" for the cost-benefit study by creating three markets (PJM, MISO, and TVA) for the LGE/KU system to transact against rather than just one as is typically modeled. This enhancement was made to allow for greater model detail of transfer capability and market prices.

Dr. McNamara's Criticisms of the Companies' Models and Methods

Q. What is Dr. McNamara's opinion of the Companies choice of models?

A. In his November 19, 2004 Rebuttal Testimony ("McNamara Rebuttal"), at page 78, line 12 and at page 81, line 5, he states he believes that the Companies' models are "inappropriate" for forecasting the Companies' production costs, purchase power expense, and off-system margins because they do not integrate a dynamic power flow analysis with production costing as does the MISO model built in PROMOD IV. He believes that the lack of a dynamic power flow analysis is so egregious that "no weight" [McNamara Rebuttal p. 81 line 8] should be given to the Companies' analysis. His testimony implies that without the dynamic power flow modeling capabilities of a PROMOD IV, there is simply no reasonable way to forecast the Companies' production costs, purchase power expense, and off-system margins.

Q. Is Dr. McNamara correct that the Companies' approach to forecasting its production costs, purchase power expense, and off-system margin is "inappropriate?"

A. No. While incorporating the dynamic power flow analysis capabilities of PROMOD IV might be able to refine the forecasts of expenses and margins, it alone does not guarantee that such forecasts are reasonable. Similarly, the use of a software product that lacks dynamic power flow analysis capabilities does not mean the Companies' forecasts are unreasonable. If all that was required to reasonably forecast future power prices and production costs was a dynamic power flow model, then the Companies would have used one. However, as I previously stated, the choice of a forecasting model is only one part of the forecasting process. Ultimately, the model must be effectively utilized by the forecaster in order to produce a reasonable forecast. All three models (PROMOD IV, MIDAS, and PROSYM) are essentially doing the same – minimizing the cost of serving load in a region. However, they go about it in different ways. Just because the Companies' approach to forecasting its production costs, purchase power expense, and off-system margins is different from Dr. McNamara's preferred approach does not automatically mean that the results cannot be relied upon by the Commission.

Q. Why did the Companies utilize three models instead of one integrated model such as PROMOD IV?

A. Using a model like PROMOD IV to forecast the Companies' generation costs, purchase power expense, and off-system sales margin is a little like using a steamroller to kill an ant. While it could use PROMOD IV to make such forecasts, the Companies do not think it is cost effective or practical to maintain and run a model of the entire Eastern Interconnect just to analyze Company-specific issues. Therefore, it uses PROSYM to model the details of its own system and allows market prices to represent the interaction of all rest of the generators in the Eastern Interconnect. To calculate those market prices, the Companies used MIDAS which, like PROMOD IV, contains information on generating units and load in the Eastern Interconnect.

As mentioned above, the only material difference in the modeling approaches taken by the Companies and Dr. McNamara is in the representation of the transmission system. Indeed PROMOD IV has a more complex representation of the transmission system than does either PROSYM or MIDAS. However, the "static" transfer capabilities calculated by MUST and input into MIDAS and PROSYM allow the Companies to reasonably analyze and forecast the costs and margins associated with its system. Essentially, PROMOD IV calculates both market prices and

Company-specific outputs in one step whereas the Companies' approach took two steps. Utilizing MIDAS and PROSYM together allows the Companies to utilize the strengths of each model to analyze critical business issues while maintaining the appropriate level of detail within each model, as well as in this case analyze with confidence the primary drivers of the revenues and costs under the "In-MISO" and TORC options.

Response to Dr. McNamara's Critique and a Description of Issues with His Own Modeling of the Companies Options

Q. Does the use of a "static" representation of transfer capability necessarily produce inferior results?

A. No. As shown in Mr. Gallus' September 29, 2004 Supplemental Testimony, the forecasted volumes of off-system purchases and sales produced by PROSYM were in line with the Companies' historical experience. Using a more detailed model of the transmission system is only advantageous if it produces "reasonable" results.

A detailed model requires <u>accurate</u> detailed data, otherwise the additional detail is not adding value to the forecasting process and may, in fact, detract from it. For example, PROMOD IV requires an hourly load forecast for each and every load bus in the entire Eastern Interconnect. Because load forecasts are not produced by utilities at that level of granularity, Dr. McNamara allocated the control area load forecasts across each load bus based on a fixed distribution factor [MISO Response to LG&E/KU Data Request #61 filed December 20, 2004]. This simplifying assumption has the effect of modeling each load bus with the exact same hourly load shape and annual load factor whether that load bus is in a residential neighborhood or serves an aluminum smelter. So while Dr. McNamara may claim that he is "dynamically" modeling load flow, he does so in a very "static" and unrealistic manner. Because of the importance he places on transmission model complexity

[McNamara Rebuttal, page 77 lines 6-13] in justifying his results as compared to the Companies' results, his oversimplification of how load changes hour-to-hour at each bus calls into question the validity of his results given the importance he places on "dynamic" load flows.

Q. How do these simplifying assumptions in the PROMOD IV model impact the forecasting of the Companies' costs and margins?

A. Without passing judgment on who has the better model or assumptions, it is important to note that simplifying assumptions are often required to build any model. The key is to ensure that the simplifying assumptions make sense within the context of the model being used and that they lead to reasonable results. The simplifying assumption on hourly load distribution utilized by Dr. McNamara could lead PROMOD IV, which requires bus-level load information, to produce erroneous results regarding the Companies' costs and margins just as much, if not more so, than the Companies' simplifying assumption regarding "static" transfer capability used in MIDAS and PROSYM which do not require bus-level detail on load. That is why it is important to evaluate the totality of the forecasting process and not just the software utilized to produce the forecast when considering the reasonableness of a forecast.

Q. Please describe the benefits of the Companies' approach to forecasting costs and margins as compared to Dr. McNamara's approach?

A. There are two key benefits to the Companies' approach to modeling its system: detailed focus on key issues and reduced computation time. The key issue facing the Companies in this particular study is how our own generation costs compare to the market. Using PROSYM allowed the Companies to focus on detailed information regarding its generating plants and load and changes to these over time without having to gather and evaluate similar information for the entire Eastern Interconnect.

The behavior of the rest of the Eastern Interconnect was reflected in the market price information calculated in MIDAS where the simplified transmission assumptions allowed the Company to evaluate the impacts of changing load growth, fuel prices, and resource mix over time. By using the strengths of each model, the Companies were able to efficiently and effectively evaluate the impacts on its costs and margins under different RTO constructs and over time.

As previously mentioned, Dr. McNamara relies heavily on the detailed information utilized by PROMOD IV to justify the reasonableness of his results. However, these details do not come without a cost, one of them being computer run time. Dr. McNamara seems to take great pride in the fact that it takes "70 hours of continuous run time to complete each one-year simulation."[2] While this may sound impressive, this lengthy run time likely contributes to the fact that only one year of the model was run whereas, the Companies' models (MIDAS and PROSYM) were able to be run for each and every year of the study period (2005 to 2010). This allowed the Companies to <u>actually</u> evaluate the impacts of changing load, fuel costs, generation mix, etc, on both electricity prices and the Companies' costs and margins over time instead of having to simply <u>assert</u> that changes in key variables over time would not impact the results as Dr. McNamara was forced to do.[3] By modeling only one year, Dr. McNamara, in effect, assumes for the entire Eastern Interconnect from 2005 to 2010 that: i) load growth will be exactly the same at each and every load bus, ii) each and every generating unit and the transmission system grow proportionally to load, and iii) relative fuel prices will not change. All of these simplifying and "static" assumptions would seem to be questionable and could lead to an unreasonable forecast of the Companies' costs and margins, especially over the long time horizon

[2] McNamara Rebuttal, Page 80 lines 25-26.
[3] McNamara Rebuttal Page 71 lines 8-15.

of this study. This is another example of why greater complexity does not *per se* result in a more reasonable forecast.

Q. Does the "static" transmission system assumed in MIDAS result in unreasonable electricity price forecasts?

A. No. MIDAS is essentially doing the same type of calculations (minimizing the cost to serve load) as PROMOD IV except with a simplified approach to transmission. To evaluate the reasonableness of the MIDAS and PROMOD IV electricity price forecast, it is important to compare each forecast to recent history as well as observable forward prices. Since Dr. McNamara only ran PROMOD IV for 2005, I can only compare that particular year. Note that this implies that Dr. McNamara is forecasting that electricity prices will be constant for 2005 through 2010 in his study.

TABLE 1
Comparison of Market Price Forecasts
On-Peak (5x16)

	Into-Cinergy Actual	**Into-Cinergy** MegaWatt Daily Forward Price June 25, 2004(1)	**Into-Cinergy** MegaWatt Daily Forward Price November 19, 2004(2)	**Into MISO** RTO Case MIDAS(3)	**Into-Cinergy Load Zone LMP** PROMOD IV(4)
2000	36.61				
2001	35.19				
2002	27.03				
2003	37.57				
2004	43.47				
2005		46.35	49.50	48.96	26.33

(1) Forward market at the time the MIDAS forecast was prepared.

(2) Forward market at the time Dr. McNamara's rebuttal testimony was filed.

(3) Appendix B - Table 2 - Martyn Gallus Supplemental Testimony, September 29, 2004

(4) Calculated from MISO response to Companies' data request filed December 20, 2004, Average LMP at Cinergy Load Zone.

It is easy to see that Dr. McNamara's price forecast is quite low compared to both recent history and the forward market. While it will not be possible to judge the accuracy of either party's forecast for some time, the available evidence calls into question Dr. McNamara's assertion that, "…it [PROMOD IV] much more closely approximates the operation of the Midwest ISO power markets."[4] I think it would be rather incredible for the Day 2 market to result in a nearly 40 percent decline in wholesale electricity prices from 2004 to 2005 that the forecasts from PROMOD IV imply. In spite of MIDAS' "static" approach to modeling transmission, it appears to produce the more reasonable forecast of electricity prices for 2005.[5]

Q. How does the electricity price forecast impact the results of each party's study?

A. As I stated above, the key issue facing the Companies in this particular study is how our own generation costs compare to the market. The fact that the Companies' forecast of electricity prices appears more reasonable than do those of Dr. McNamara enhances my confidence in the overall results produced by the Companies (particularly since the Company has good information regarding its forecasted fuel costs) and diminishes my confidence in Dr. McNamara's study. Consequently, the fact that the Companies' models have utilized more reasonable price forecasts likely contributes to the forecast of off-system sales and purchases volumes that are consistent with its historical experience.[6]

In some instances, it is possible to de-emphasize the importance of absolute values and instead just focus on the differences between cases. However, that is

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[4] McNamara Rebuttal, Page 80, lines 24-25.

[5] It is interesting to note that Dr. McNamara has used this rather low forecast of electricity prices at FERC as well. In Exhibit RRM-3 of his testimony in dockets ER04-691-000 and EL04-104-000 supporting the EMT, he forecasts 2005 7x24 prices in MISO to be $26.70 / MWH. This compares to a 7x24 price of $21.66 / MWH for the LG&E load zone in the cost-benefit study that MISO filed in this case.

[6] See Tables 5 & 6 at page 9 of the Supplemental Testimony of Martyn Gallus filed September 29, 2004

usually the case when the absolute value is not known with certainty but the forecast is likely to be in the ballpark. Unfortunately for Dr. McNamara, the magnitude of the difference between his forecast of electricity prices and both forward and historical prices make it extremely difficult to make that assertion.

The large divergence shown in Table 1 between the Companies' and Dr. McNamara's forecasts of future electricity prices is an example of the importance of bringing experience and capabilities to bear on evaluating forecast results. It is inconceivable that an entity that has significant experience in the Midwest electricity markets, like the Companies, would utilize such an obviously unreasonable forecast of prices as that developed by Dr. McNamara.

Q. Please describe the capacity and production cost assumptions utilized by the Companies in PROSYM.

A. The capacity and production cost assumptions utilized in PROSYM are shown in Appendix B. The Companies have a total summer capacity of 8,215 MW, including 605 MW of purchases from Ohio Valley Electric Company ("OVEC"), Electric Energy Inc. ("EEI") and Owensboro Municipal Utilities ("OMU"). The assumptions used to develop the production cost for each unit are discussed in Appendix B of Mr. Gallus' Supplemental Testimony. The costs shown in my Appendix B include fuel and variable O&M.

Q. How do the Companies' assumptions regarding its generating plants compare to those used by Dr. McNamara?

A. Dr. McNamara's representation of the Companies' generating fleet is shown in Appendix B.[7] His view of the Companies' Total Owned Generation Plant (7,511 MW) is very similar to our own view (7,610 MW summer rating). He is only missing

[7] The capacity and production cost values shown in Appendix B come from Dr. McNamara's Response to the Companies' Data Request No. 28 filed on December 20, 2004.

98 MW of inlet air cooling capacity on the 11N2 units at Brown. However, his cost-benefit analysis totally excludes 409 MW of low-cost OVEC and EEI purchased capacity while at the same time including 2,357 MW of capacity that do not belong to the Companies. The bulk of this capacity (1,772 MW) is leased by Western Kentucky Energy ("WKE") from Big Rivers Electric Corporation. As the Commission is aware, WKE is an unregulated affiliate of the Companies and does not supply any capacity to them nor do the Companies have any legal right to call upon WKE's capacity. Dr. McNamara's cost-benefit analysis also included Dynegy's Bluegrass project in the Companies' generating fleet as well as two small coal units at Green River that have been retired. As a result of this mischaracterization of the Companies' generating fleet, Dr. McNamara overstates the Companies' summer capacity by 2,039 MW.[8]

Appendix B also compares the fuel and variable O&M cost assumptions for the Companies' generating units utilized in PROSYM and PROMOD IV. While Dr. McNamara's assumptions are slightly higher than the Companies, they are unlikely to be large enough to produce any sizable volume differences. If anything, Dr. McNamara's low forecast of electricity prices combined with generating unit costs that are similar to the Companies should result in lower forecasted off-system margins as compared to the Companies' forecast of those margins.

Q. Are there any implications of Dr. McNamara's misrepresentation of the Companies' generating capacity?

A. Yes. Dr. McNamara states on page 83 lines 1-9 that the problems with the Companies' models are "self-evident" because PROMOD IV forecasts "much higher

[8] Dr. McNamara's inclusion of WKE generation as part of the Companies' generating fleet is puzzling when one considers that the Companies are required by the Network Operating Agreement to annually report to MISO a 10-year forecast of its designated network resources and load. This information was last filed with Mr. Guy Ridgely in Tariff Administration at MISO on April 19, 2004 and does not include the WKE generation.

transaction volumes" for LG&E/KU in both the TORC and MISO cases. As can be seen in Table 2, Dr. McNamara's forecast of both off-system sales and purchase are orders of magnitude different from the Companies' historical experience and forecasts. The explanation offered by Dr. McNamara as to why his forecasts are reasonable is that PROMOD IV "was designed to identify" increased sales and purchase opportunities associated with regional economic dispatch. Unfortunately, the extra volumes found by Dr. McNamara seem to result from his lack of knowledge about the Companies' generating units rather than in PROMOD IV's ability to identify trades or any deficiency in the Companies' modeling capabilities.

Table 2a
LG&E and KU Off-system Sales and Purchases
In-MISO Cases
(GWH)

	History		Mr. Gallus (PROSYM)		Dr. McNamara (PROMOD IV)	
	Sales	*Purchases*	*Sales*	*Purchases*	*Sales*	*Purchases*
2000	5,938	1,059				
2001	6,026	1,005				
2002	3,754	597				
2003	4,381	297				
2004	4,219	98				
2005			6,302	351	14,177	35
2006			4,975	429	14,177	35
2007			4,014	597	14,177	35
2008			4,143	846	14,177	35
2009			4,064	894	14,177	35
2010			4,416	751	14,177	35

The net effect of the inappropriate attribution of the WKE generating units to the Companies and ignoring their share of EEI and OVEC capacity is the overstatement of off-system sales by 8,472 GWH while at the same time understating purchases by 520 GWH in Dr. McNamara's "In MISO" case. Correcting for these errors, off-system sales and purchases are 5,705 GWH and 555 GWH respectively, which are more in-line with the Companies' forecasts shown in Table 2a. Similarly, these errors cause Dr. McNamara to overstate off-system sales by 6,842 GWH and understate purchases by 1,215 GWH in his "TORC" case. Correcting for these errors, off-system sales and purchases are 2,285 GWH and 1,239 GWH respectively, both of which are significantly different from the Companies' experience in the last three years and the Companies' forecast.[9] Since the TORC case is very similar to the current environment, Dr. McNamara's results imply that, absent a Day 2 market, the Companies' off-system sales would be cut in half and that it would immediately see sizable purchase power opportunities, both of which seem implausible. As Table 2b shows, the Companies' forecasted volumes of off-system sales and purchases change very little in the TORC case as compared to the In MISO case. As Mr. Gallus explained in his September 29, 2004 Supplemental Testimony, this result is reasonable given the modeled impacts of the Day 2 market on electricity prices and transfer capability.

Table 2b
LG&E and KU Off-system Sales and Purchases
TORC Cases
(GWH)

	History		Mr. Gallus (PROSYM)		Dr. McNamara (PROMOD IV)	
	Sales	***Purchases***	***Sales***	***Purchases***	***Sales***	***Purchases***
2000	5,938	1,059				
2001	6,026	1,005				
2002	3,754	597				
2003	4,381	297				
2004	4,219	98				
2005			6,240	346	9,127	24

[9] These adjustments were calculated using data from files "In MISO Total Costs.zip" and "Out of MISO Total Costs.zip" filed on December 20, 2004 in response to LG&E/KU's December 7, 2004 Supplemental Data Requests.

2006			4,957	343	9,127	24
2007			3,996	487	9,127	24
2008			4,129	724	9,127	24
2009			4,044	825	9,127	24
2010			4,393	726	9,127	24

It is important to understand that Dr. McNamara's error results, in part, from how he derives off-system sales and purchases. The off-system volumes are not based on moving electricity off of or onto the Companies' transmission system (as in PROSYM), but rather are merely the hourly volumetric difference between the Companies' load and whatever generators he assigned to the Companies. Had Dr. McNamara noted that the WKE units are in the Big Rivers Control area (which is not even in MISO) then the Companies would have needed transmission out of Big Rivers into the Companies' control area. A recent check of Big Rivers' OASIS shows that there is only 339 MW of firm ATC, not the over 1,700 MW that would have been required to utilize the WKE units to serve the Companies' load.

Both of these errors are good examples of what I meant when I said that it is important that an experienced and capable analyst evaluate the forecast results for reasonableness and that a technically sophisticated model, in and of itself, does not guarantee a reasonable forecast.

Conclusions

Q. Do you believe that the Companies' modeling approach produced reasonable forecasts of its production costs, purchase power expense, and off-system sales?

A. Yes. As I have discussed, the Companies had experienced staff employ sophisticated models, utilizing reasonable assumptions that produced reasonable forecasts which were reviewed and evaluated against historical and market information. These are the same models and methods that have long been utilized to evaluate important issues at this Commission. Dr. McNamara pleads that, "...the Commission should give no weight to the results of his [Mr. Gallus] production costing analysis..."[10] The Commission should reject his pleas because:

- The Companies have more experience modeling the LG&E/KU system than does Dr. McNamara,
- The Companies' model produced a forecast of electricity prices that is more consistent with market forward prices and historical prices than did Dr. McNamara's model,
- The Companies' model produced forecasts of off-system sales and purchase volumes for LG&E/KU that are more consistent with history than did Dr. McNamara's model, and
- The Companies have the only forecast of LG&E/KU system production costs, purchase power expense, and off-system sales margins which correctly identified the generating units actually owned or controlled by the Companies.

Q. Does this conclude your testimony?

A. Yes, it does.

[10] McNamara Rebuttal, Page 81, lines 8-9.

Appendix A

David S. Sinclair

Director – Market Analysis and Valuation
LG&E Energy Service Inc.
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40202
(502) 627-4653

Education

Arizona State University, MBA - 1991
Arizona State University, MS in Economics - 1984
University of Missouri, Kansas City, BA in Economics - 1982

Previous Positions

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax, Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Appendix B

Generating Capacity of LG&E and KU

	PROSYM Net Capacity (MW)		PROMOD IV (MW)	2005 Fuel and Variable O&M ($/MWH)	
Plant Name	**Winter**	**Summer**		**PROSYM[1]**	**PROMOD IV[2]**
Brown 1	102	101	101	19.18	17.95
Brown 2	169	167	169	17.34	16.93
Brown 3	433	429	429	18.42	17.10
Inlet Air Cooling on 11N2		98			
Brown 5	143	117	117	73.84	84.64
Brown 6-7	336	308	308	67.19	73.33
Brown 8-11	560	424	424	74.21	81.59
Cane Run 4	155	155	155	16.32	13.43
Cane Run 5	168	168	168	16.38	12.61
Cane Run 6	240	240	240	16.12	12.58
Dix Dam 1-3	24	24	2		
Ghent 1	468	475	475	13.62	14.49
Ghent 2	466	484	477	18.67	14.36
Ghent 3	495	493	487	20.04	15.60
Ghent 4	495	493	489	20.02	15.48
Green River 3	71	68	70	17.52	16.73
Green River 4	102	95	99	16.16	15.50
Haefling 1-3	42	36	36	99.52	130.35
Mill Creek 1	303	303	303	13.57	12.75
Mill Creek 2	299	301	301	13.99	13.22
Mill Creek 3	397	391	397	14.06	12.90
Mill Creek 4	492	477	482	14.04	12.77
Ohio Falls 1-8 [1]	32	48	48		
Paddys Run 13	175	158	175	63.41	69.38
Trimble County 1 [2]	386	383	386	13.83	11.28
Trimble County 5-10	1,080	960	960	72.20	73.61
Tyrone 1	30	27	27	83.88	104.52
Tyrone 2	33	31	31	83.87	104.52
Tyrone 3	73	71	72	27.09	21.89
Cane Run 11	14	14	12	83.99	115.57
Paddy's Run 11	13	12	12	79.42	104.63
Paddy's Run 12	28	23	23	88.42	110.62
Waterside 7-8	26	22	22	96.37	124.27
Zorn 1	16	14	14	109.28	121.40
Total Owned Generation Plant	**7,866**	**7,610**	**7,511**		

Purchases

OMU	196	196	386*
EEI	200	200	0
OVEC	209	209	0
Total Purchases	**605**	**605**	**386**

Non LG&E / KU Generation			
Western Kentucky Energy Generation			1,772
Dynegy Bluegrass Generation			546
Retired KU Units (Green River 1&2)			39
Total Non LG&E / KU Generation			**2,357**
Total Generation	**8,471**	**8,215**	**10,254**

1 - MISO response to Data Request #28 filed December 20, 2004.
2 - Input data used by LG&E/KU in the PROSYM model.
* PROMOD IV included OMU load in the KU load zone so this represents the total OMU capacity, not just KU's share.

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is the Director of Market Analysis and Valuation for LG&E Energy Services Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

DAVID S. SINCLAIR

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of January 2005.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	) CASE NO. 2003-00266

SUPPLEMENTAL REBUTTAL TESTIMONY OF
MATHEW J. MOREY

ON BEHALF OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY

Filed: January 10, 2005

Name *and Qualifications*

Q. Please state your name, current position and business address.

A. My name is Mathew J. Morey. I am Senior Consultant with Laurits R. Christensen Associates, Inc. My business address is 409 Cambridge Road, Alexandria, Virginia. Laurits R. Christensen Associates, Inc.'s principal business address is 4610 University Avenue, Suite 700 Madison, Wisconsin.

Q. Have you previously testified on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU" or "Companies") in this proceeding?

A. Yes, I prepared direct supplemental testimony in this proceeding on the Companies' behalf that was filed on September 29, 2004.

I also prepared and submitted direct and rebuttal testimony to the Kentucky Public Service Commission ("KPSC" or "Commission") on behalf of the Companies in 2003 and 2004 in this same case, Case No. 2003-00266.

Q. Were the supplemental rebuttal testimony and the exhibits prepared by you or under your supervision?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony responds to the testimony submitted by Dr. McNamara that reports on MISO's independent supplemental investigation into the question of the size of the net benefits to LG&E/KU and its retail customers of continued membership in MISO ("In MISO option") relative to the option of LG&E/KU operating as a standalone transmission system operator ("TORC option").

Summary and Conclusions

Q. Please summarize your rebuttal testimony and conclusions.

A. Dr. McNamara asserts on page 2, lines 11-12 of his testimony that his supplemental rebuttal testimony confirms that there are net "economic and reliability benefits to Kentucky if the utilities remain within the RTO." Similarly, he asserts that the supplemental cost-benefit study conducted by MISO, confirms the conclusions reached in the direct testimony submitted to the Commission in December 2003 that there are "substantial economic and reliability benefits that will accrue to LG&E/KU from their continued membership in the Midwest ISO," on page 2, lines 17-18 of his testimony.

My rebuttal testimony addresses Dr. McNamara's first point, that there are <u>substantial</u> economic benefits that "will accrue to LG&E/KU from their continued membership in the Midwest ISO." In particular, my testimony addresses the quantitative short-term cost-benefit analysis conducted by the Midwest ISO upon which Dr. McNamara rests a good portion of his case regarding these claims of "substantial" economic benefits.

The response to his second point concerning the impact on reliability regarding the Companies' continued membership in MISO or withdrawal from MISO is contained in the rebuttal testimony of Mr. Mark Johnson filed today on behalf of the Companies. Other points that Dr. McNamara makes in his testimony are simply irrelevant to this proceeding because they do not really answer the principal question of concern to the Commission: Do the incremental benefits of the Companies' continued membership in MISO outweigh the incremental costs?

Dr. McNamara's claims at page 4, lines 15 through 28, that the Companies (and their customers) stand to gain $43.9 million per year by remaining members of MISO in the Day Two Market compared to exiting to operate as a TORC. However, my examination of the work papers and other information that MISO supplied in response to the Companies' data requests reveals that MISO's cost-benefit study suffers from several errors that totally invalidate the results of the study and Dr. McNamara's testimony which relies upon such results. The errors in the study include the following:

1. the inappropriate attribution to LG&E/KU of revenues and costs associated with output from generating units which the Companies do not own, control or operate,
2. the failure to attribute to LG&E/KU revenues and costs associated with output from generating units which the Companies do, ,
3. a mistake in the computation of congestion costs, and
4. an inappropriate use and manipulation of a portfolio of Financial Transmission Rights ("FTRs") developed for a totally unrelated MISO exercise conducted in early 2004. Thus, there is a logical inconsistency between the portfolio of generating units used to estimate the FTR values in current simulation and the fleet of units that LG&E/KU was given financial rights to in the simulation).

The distortions these errors create in the outcomes of the MISO cost-benefit study provide unstable foundation upon which Dr. McNamara builds his claims that the In MISO option is preferred to the TORC option. The foundation collapses when adjustments are made for these errors. By making several conservative adjustments to correct for these errors, adjustments based entirely upon MISO's own study numbers, the $43.9 million benefit is reduced to $4.9 million.

The full impacts of these errors on the MISO study, in particular those pertaining to generation units, have not been traced out fully because of time limitations. Therefore, I cannot conclude that the $4.9 million represents a final estimate of the net recurring (i.e., annual) benefit of the MISO option. Rather, this value should be viewed as an illustration of the systemic problems permeating this study that render its original results completely unreliable.

With the adjustments that I and the Companies staff have made based on MISO's own numbers, the MISO analysis comes much closer to agreeing with the Companies' study. Taking the $4.9 million benefit figure that I obtained by adjusting for the errors in the MISO study together with an annual average of the Companies' own estimates of the net recurring cost of the In MISO option under the TORC High-transfer Scenario, the net benefit of the MISO option ranges from a negative $13.3 million per year (i.e., a loss to Kentucky retail customers) to a positive $4.9 million per year. Given the tremendous uncertainty surrounding the estimates of off-system sales revenues, FTR revenues, congestion costs, and uplift costs, a range of recurring net benefits of the MISO option that is predominantly negative is not an encouraging sign that positive benefits can be expected to be forthcoming from MISO membership during the study period. Thus, from this corrected analysis I conclude that the short-term quantifiable costs of the Companies' continued membership in MISO outweigh the short-term quantifiable benefits. The TORC option remains economically superior to the In MISO option.

Overview of the Errors Made in the MISO Study Regarding Generation

Q. What errors has MISO made with respect to generation in conducting its cost-benefit study and how do those errors affect the results?

A. In my estimation, the first two errors that I will discuss, in the set of errors that MISO made completely invalidates its cost-benefit study. Specifically, the first is that MISO incorrectly included in the list of generators attributed to LG&E/KU, at least with respect to the revenues from sales to native load or off-system sales, fourteen generating units totaling 2,329 MW of capacity. The consistency of the results on off-system sales MWh and revenues across all the scenarios considered by MISO in its study, including various sensitivity cases, suggests that, in every case, the revenues attached to the output from at least a significant proportion of this mistakenly included capacity were attributed to the Companies. The second error is that MISO incorrectly excluded about 400 MW of capacity owned by EEI and OVEC to which the Companies have a contractual right. I will subsequently discuss these two errors in more detail.

As a consequence of these two mistakes, the analysis MISO conducted significantly overestimates the MWh attributed to off-system sales and hence the revenues from those sales and underestimates the MWh of purchased power and the costs of that power. I will discuss the numerical impacts in a moment.

Since the mistakes are made in all the scenarios and sensitivity studies MISO examined, one might imagine that the impact would be proportional and would thus "wash out" when considering the difference between the In MISO option and the TORC option to derive the net recurring cost of the MISO option. However, there are significant differences in the relative impacts of these mistakes on the results obtained for the In MISO and TORC cases. Consequently, the biases that the mistakes introduce into the results for the two options are not of the same magnitude, and do not just balance out when looking at differences between the two cases.

Without an excruciatingly detailed and lengthy examination of the PROMOD IV analysis that might require a complete rerun of the simulations, I cannot determine all the reasons why the results are not of the same magnitude. It is also difficult to understand how such an error could have occurred when MISO had been given the results of the Companies' own study long before it filed its own supplemental cost-benefit analysis. The Companies' study could easily have been used as a benchmark. In addition, in preparing for the Day Two Market, the Companies have supplied MISO with sufficient information and there is sufficient information that is publicly available, that such a mistake could have been easily avoided.

For both the In MISO and TORC option scenarios in the MISO study, these grave mistakes in effect incorrectly awarded the Companies rights to the revenues associated with the MWh dispatched from at least 1,499 MW of capacity that either LG&E/KU do not own, control or operate or which is retired from operation. And correspondingly, MISO failed to award the Companies the rights to revenues associated with MWh generated from 409 MW of capacity owned by LG&E/KU under contract. For example, for the In MISO base case, generating units that MISO mistakenly gave the Companies financial rights to (i.e., Coleman, Green, Reid and Wilson units) were responsible for generating 9,826,302 MWh. I will discuss these units and others in more detail later in my testimony. The sales from these MWh resulted in revenues of $157,186,343, which MISO ascribed incorrectly to LG&E/KU.

MISO makes other errors in various calculations it has made, but the error of including at least 1,499 MW of non-LG&E/KU generation in the Companies' generation portfolio and excluding 409 MW from the portfolio is so grave as to make all other errors pale in comparison.[1] The error nullifies all of the quantitative results of the MISO cost-benefit study that depend on the assumptions about what generating units within the simulated regional dispatch the Companies have rights to revenues from, what generation costs the Companies are responsible for, and what locational prices are set within the control area or in adjacent control areas that determine congestion costs and values of financial transmission rights. All of the

[1] The value 1,499 MW represents the sum of the capacities of the Coleman, Green, Reid, and Wilson units and the Green River units which are reported below in Table 1. These were the units reported on Exhibit RRM-

results in the MISO cost-benefit study are derived from or linked in some fashion to the simulated dispatch of whatever generation fleet MISO assumes is rightfully LG&E/KU's. I offer a list of those principal elements of the cost-benefit study that I believe are affected:

- Total MWh, total generation revenue, and generation costs,
- Off-system Sales MWh, revenues, costs and margins,
- Chronological hourly congestion costs, and therefore total congestion costs,
- Total costs of generation MWh to serve native load,
- Off-system purchase MWh, costs, and
- FTR revenues.

Other elements of the study may also be affected but this list contains what I believe are the most critical elements. These elements are critical to the estimation of the benefits that Dr. McNamara claims have been revealed by MISO's cost-benefit study. Because of the mistaken inclusion of the non-LG&E/KU generating units, the estimates of these elements are severely biased. The biases appear to favor the In MISO option in all the cases considered in the study.

Q. What specific generating units are involved in the errors that MISO made in its simulation?

A. Table 1 summarizes the information on the generating units that have been mistakenly "assigned" to LG&E/KU from a financial perspective, as well as those

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Table 5 Unit 2005 Capacity Factor and thus were the only units that could be definitively identified as having been credited to LG&E/KU for revenue and cost purposes.

units that were mistakenly omitted from the Companies' generation portfolio to which the Companies have contractual rights as well as the units that are owned by LG&E/KU but now retired from operation.

Table 1 also summarizes additional information about these units including their fuel type, capacity as reported in the spreadsheet that accompanies MISO's response to the Companies' Data Request No. 28 ("Response 28"), capacity factors as reported in "Exhibit RRM-Table 5 Unit 2005 Capacity Factor" ("Table 5"), the MWh generated from those units as implied by the reported capacity factors (i.e., obtained by multiplying the MW capacity by the capacity factor and multiplying that product by 8,760 hours), and the actual MWh as determined by an examination of the spreadsheets that report each unit's MWh output by hour as provided by MISO on December 20, 2004 in response to the Companies' follow-up to its Data Request No. 54 ("Response 54 Follow-up ").

Table 1
Summary of Generating Unit Errors
In the MISO Cost-Benefit Study

Unit Name	Unit Type	Capacity (MW)	Reported Capacity Factor	MWh Implied by CF	Actual MWh from MISO Study
Units Erroneously Attributed to LG&E/KU Generation Fleet					
Coleman 1	Coal	150	82%	1,077,480	3,008,503
Coleman 2	Coal	150	71%	932,940	
Coleman 3	Coal	155	74%	972,360	
Green 1	Coal	231	86%	1,740,262	3,428,383
Green 2	Coal	223	86%	1,679,993	
Reid 1	Coal	65	46%	261,924	262,630
Reid 2	Combustion Turbine	65	0%	0	

Wilson 1	Coal	420.21	83%	3,055,263	3,126,786
Dynegy 1, 2, 3	Combustion Turbines	546 total	Not reported	NA	3,627
Paris (PCU)	Diesel	11.08	Not reported	NA	1,065
Henderson II 1, 2	Coal	159, 154	Not reported	NA	1,976,324
Totals		**2,329**		**9,458,560**	**11,807,318**
Units Erroneously Omitted from LG&E/KU Generation Fleet					
EEI	Coal	200 contract	Not reported	NA	1,542,216
OVEC	Coal	209 contract	Not reported	NA	1,337,563
Totals		**409**		**NA**	**2,879,779**
Retired Units Erroneously Included in LG&E/KU Generation Fleet					
Green River 1,2	Coal	19.8, 19.73	Not reported	NA	111,431
Totals		**39.53**			**111,431**

The Coleman, Green, Reid and Wilson units are all owned by Big Rivers Electric Corporation ("BREC") and leased to Western Kentucky Energy ("WKE"), an affiliate of LG&E/KU. However, LG&E/KU has no rights to the output or revenues from sales made from those units. In addition, BREC is a separate control area that would not be part of the MISO regional dispatch footprint. The three Dynegy units were not included in Exhibit RRM-Table 5, but they were labeled as LG&E/KU units within the spreadsheets supplied with Response 54 Follow-up and were listed as part of the LG&E/KU supply curve in Response 28. The Dynegy units would likely fall within the MISO regional dispatch footprint. The Paris (PCU) unit are diesel units owned by the city of Paris, which is a full requirements customer of KU, and would fall within the LG&E/KU control area and the MISO footprint under the Day Two Market. The Henderson II units are jointly owned by the city of Henderson and BREC, and fall within the BREC control area, and therefore, would not be a part of the MISO dispatch footprint. The most egregious of the mistaken inclusions are those units that reside within the BREC control area, totaling 1,772 MW of capacity and accounting for 11,802,625 MWh which are included as part of the Day Two Market security constrained regional dispatch within the LG&E/KU control area.

Even though it is well known that LG&E/KU have contracts with Ohio Valley Electric Company ("OVEC") and Electric Energy Inc. ("EEI"), LG&E/KU were not credited for the revenues from the 2,879,779 MWh generated from the 409 MW of capacity under contract with those entities. The Green River 1 and Green River 2 units have been retired and therefore should not show any MWh in production, even though they are owned by KU.

Q. What are the general conclusions you reach when these errors in the MISO analysis are accounted for?

A. Because the errors MISO made permeate every aspect of the analysis, it is difficult to sort out and adjust all of the results that stem from these mistakes that MISO made in conducting its study. However, one can make adjustments to the major categories of revenues and MWh, especially for off-system sales to account for these errors. These adjustments at least demonstrate that had the MISO study been free of these errors, the MISO study and the Companies' cost-benefit analysis would be in much closer agreement and that the TORC option was the preferred path for the Companies to take. I will turn to a more detailed discussion of the adjustments in a moment.

Overview of the Differences Between MISO's Cost-Benefit Analysis and the Companies' Cost-Benefit Analysis That Result from MISO's Errors Regarding Generation

Q. Before discussing how the two cost-benefit studies differ as a result of the major errors MISO has made, are there any places where the results of the two studies are in general agreement?

A. Yes, several cost categories are in definite agreement when considering the In MISO option. First of all, the studies are in general agreement regarding MISO's annual administrative fees, assuming no sharp upward trend in MISO's administrative costs. Each cost-benefit study estimates that the average annual cost burden for MISO administration to lie between $14 and $15 million. The two studies also are in general agreement concerning Transmission System Operations costs that fall somewhere between $1.3 and $1.4 million per year under the In MISO option. And, finally, the two studies are in general agreement about uplift costs under the In MISO option, each estimating those to average about $1.4 million per annum.[2] Consequently, there appears to be general agreement between the two studies regarding certain recurring costs that in total range between $16.7 million and $17.8 million per annum. With this agreement on what I perceive as the minimum level of costs that the Companies and Kentucky retail customers would face annually under the In MISO option, the question becomes whether the benefits, such as off-system sales margins and FTR revenues or cost savings in production from centralized

[2] I note that these estimates in both cost-benefit studies are subject to a great deal of uncertainty because they are based on very limited amounts of information regarding the Day Two Market. The estimates are believed to

dispatch are large enough to offset these costs. As I have indicated, the errors that have been made by MISO in conducting its cost-benefit study invalidate results of its analysis. The Companies' cost-benefit study, which stands as the only truly reliable study presented in this proceeding, leads unavoidably to the conclusion that the TORC option is the economically preferable course to follow.

Q. **Please elaborate on the major differences between MISO's analysis and that of the Companies'.**

A. A significant difference between MISO's and the Companies' quantitative estimates of the recurring costs and revenues of the In MISO option compared to the TORC option arise principally from the major errors that MISO made of incorrectly giving the Companies financial rights to the revenues of at least 1,772 MW of generating capacity that should not be included in the Companies generation fleet and failing to accord the Companies with financial rights to 409 MW of generation that the Companies have under contract. As I stated, this mistake affects all of the major elements of the cost-benefit study that feed into the estimates of the benefits MISO finds for the In MISO option. I will return to this topic later in my testimony.

Table 2A compares the differences in one-time costs, which consist entirely of the exit fee. The MISO and LG&E/KU analyses show that the exit fee will be \$40.2 million and \$28.4 million, respectively; so, for this cost category, these figures represent the relative net benefits of remaining within MISO. The positive \$11.8

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be conservative and designed to provide, in the cost-benefit study, a placeholder for what is known to be a category of cost. The estimate in the Companies' study is believed to be a lower bound on these costs.

million difference shows that the MISO analysis finds a greater benefit to the Companies' remaining in MISO than the Companies find. The difference in the estimates stems from differences in assumptions about the billing determinants that are the basis for calculating the Companies' share of the unamortized capital costs under Schedules 10, 16 and 17. Even if I were to accept MISO's estimate of the exit fee, the conclusion from the Companies' cost-benefit study would be unchanged; the TORC option is still preferred.

Table 2A.
Relative One-Time Benefits of MISO Membership per the MISO and LG&E/KU Cost-Benefit Studies (millions of dollars)

Category	MISO Analysis	LG&E/KU Analysis	Difference
Exit Fee	40.2	28.4	11.8

As I indicated above, a major difference between the Companies' analysis and MISO's analysis stems from MISO's errors regarding the generating units that are, in effect, counted, at least financially, among the Companies' fleet. Table 2B compares the recurring operational costs and revenues for MISO's In MISO base case scenario, which is based on the PROMOD IV 2005 year simulation MISO conducted, and an average of results of the In MISO base case analysis estimated by the Companies for the period 2005 to 2010. MISO simulated only 2005 in its analysis and assumed that the results for 2005 would hold for all other years in the study period, 2006 to 2010. Consequently, I felt that a reasonable comparison for purposes of demonstrating the differences between the two studies could be based on computing a simple arithmetic average over the six years for each cost and revenue category estimated in the Companies' analysis.

The problems with MISO's analysis become readily apparent from the comparison to the LG&E/KU analysis in Table 2B. For example, MISO's estimate for In MISO base case of the total generation costs to serve native load customers is $661.25 million, whereas the average of the Companies' estimates is $834.16 million (refer to row 6 in Table 2.B). MISO's mistake is evident.

I am not sure how much of the total output from the generation units that are listed in Table 1 actually was credited to LG&E/KU in the MISO study, although I am confident that at least some of the output from the BREC units leased to WKE were mistakenly credited to the Companies. The only logical explanation that I can deduce to explain the difference in total generation costs is that the mistakenly included low-cost WKE-leased BREC generation is displacing some of LG&E/KU's more expensive units in the dispatch and is being given credit as actually serving native load.

By the same token, MISO's estimate of the costs to make off-system sales (OSS) – $203.96 million – are higher than the six-year average of the Companies' estimates – $108.86 million – for at least one reason, (refer to row 7 in Table 1B). That reason is that with the mistakenly included WKE-leased BREC generation producing over 9.8 million MWh to the Companies' financial credit, the Companies in MISO's analysis the Companies are able to make almost that much more in off-system sales, which naturally increases the total cost of making OSS.[3]

With respect to the estimated congestion costs, (refer to row 11 of Table 2B), MISO estimates them at $35.2 million. Notwithstanding the fact that the $35.2 million congestion cost estimate was also incorrectly calculated, a mistake I will explain later, the estimate of congestion costs depends on the difference between the locational marginal prices at the load and the generation nodes. The LMPs at the generation nodes are determined by the marginal costs of the generation fleet included in the hourly dispatch. In MISO's analysis, this includes at least 1,772 MW of generation that the Companies' do not have financial rights to, all of which is not within MISO's regional dispatch footprint under any Day Two Market scenario. This mistake on the generation side means that congestion costs attributed to LG&E/KU in the MISO study are based on an incorrect set of generation node LMPs. Thus, the congestion cost estimate is biased. I cannot say whether it is biased up or down, just that it is not an accurate estimator of congestion costs.

Table 2B Recurring Revenues and Costs for the In MISO Option per the MISO and LG&E/KU Cost-Benefit Studies (millions of dollars)

	MISO Analysis	LG&E/KU Analysis	
Category	In MISO (2005)	In MISO (Avg. 2005-2010)	MISO minus LG&E/KU
Costs			
Administrative Costs	14.15	15.08	(0.93)
Generation Costs			
A&G Costs Associated with RTO Membership Status	1.31	1.40	(0.09)
Costs to Serve Native Load	661.25	834.16	(172.91)

[3] If one accounts for all of the generation that I believe should not be included as part of the LG&E/KU control area and accounts for the generation that was not included (i.e., the EEI and OVEC contract capacity), the net MWh generated is 9,038,970 MWh

Costs to Make Off-system Sales	203.96	108.86	95.10
Transmission System Operation Costs			
A&G Costs Associated with RTO Membership	1.31	1.40	(0.09)
Transmission Payments	Reflected in OSS Revenues which are presented net of transmission payments	5.43	(5.43)
Transmission Congestion Payments	35.2	17.72	17.48
Uplift Charges	1.371	1.37	-
Legal, Regulatory & Transaction Costs	Not considered	0.85	(0.85)
Total Costs	918.55	986.27	(67.72)
Revenues			
Transmission Revenues (MISO considers Sch. 1, 7,8 & 14)	25.67	10.43	15.24
Off-system Sales Revenue (MISO nets out Transmission Payments)	265.5	160.80	104.70
FTR Revenues (as offset to congestion payments)	56.04	16.84	39.20
Share of Net Revenue from FTR Auction	2	2	-
Total Revenues	349.21	190.07	159.14
Net Recurring Cost	569.34	796.20	(226.86)

Off-system sales revenue has been estimated by MISO at $265.5 million (see row 17 of Table 2B), over $100 million higher than the average of the Companies' estimates of OSS. As I have stated, the erroneous attribution of financial rights to at least 1,772 MW of generation output enables something in the neighborhood of 9 million MWh of additional off-system sales to be made in MISO's analysis. It is therefore not surprising to see such a large difference. However, the difference would appear to exist only because of the mistake MISO made in its study.

The Companies submitted their cost-benefit study on September 29, 2004. MISO's cost-benefit study was not filed until November 19, 2004, nearly two months later. I am surprised that such vast differences between the estimates as are seen here would not have become apparent to Dr. McNamara and, at the very least, caused him to inquire of his staff or with the Companies as to whether the assumptions for MISO's analysis were accurate. There is no evidence that I am aware of that MISO attempted to contact LG&E/KU to clear up the significant discrepancies between their results and that of the Companies' prior to MISO filing its study with the Commission on November 19, 2004.

A correction can be made, at least in part, to establish a lower bound on the bias in the MISO study estimates. Mr. Sinclair discusses this correction in his rebuttal testimony. When that correction is made for this mistake using MISO's own numbers supplied in its Response 54 Followup, MISO's own numbers suggest that the Companies' OSS would be around 5.7 million MWh rather than the 14.2 million MWh reported by Dr. McNamara. The correction reduces MISO's estimate of the Companies' revenues from OSS for the In MISO option from $265.5 million to $105.9 million, a value that is consistent with the Companies' estimate of $109 million (refer to Table 2B). By the same token, under the correction, power purchases increase from $1.1 million to $13.9 million. In addition, under the correction, consistent with the reduction in OSS, the variable cost of generation to serve both native load and make OSS is reduced from $669.8 million to $561.1 million.

The difference between MISO's estimate of the recurring cost under the In MISO option and the average of the Companies' estimate of recurring cost is $226.9 million. Much of this difference can be explained by the mistake of giving financial rights to LG&E/KU to the revenues tied to the output of at least 1,772 MW of non-LG&E/KU generation capacity. The remaining estimate in Table 2B that warrants additional explanation is the FTR revenue figure that MISO estimates to be $56 million (not counting the $2 million assumed to be derived from the residual FTR auctions.). I will discuss the problems with this $56 million estimate later in my testimony.

Further evidence of the MISO mistake can be seen in a comparison of the two studies' estimates of the costs and revenues under the TORC option. These are summarized for the MISO and LG&E/KU cost-benefit studies in Table 2C. Once again, the generation costs to serve native load and to make off-system sales estimated by MISO significantly underestimate and overestimate the six-year averages of the Companies' estimates, due as I have stated in discussing the In MISO case differences seen in Table 2B, to the errors regarding the financial rights to generation output. Thus, the difference between MISO's estimate of the total costs of the TORC option and the average of the Companies' estimates appear to be explainable almost entirely by this one mistake.

On the revenue side, MISO's estimate of transmission revenue (see row 13 in Table 2C) is based on off-system sales, and off-system sales are in MISO's analysis are driven by the mistakes with the generation units as previously described. So, again the difference between MISO's total revenues under the TORC option and the average of the Companies' revenue estimates should be explainable by MISO's unfortunate errors.

Table 2C Recurring Revenues and Costs for the TORC Option per the MISO and LG&E/KU Cost-Benefit Studies (millions of dollars)

	MISO Analysis	LG&E/KU Analysis	
Category	**TORC (2005)**	**TORC (Avg. 2005-2010)**	**MISO minus LG&E/KU**
Operations Costs			
Generation Costs			
A&G Costs Associated with RTO Membership Status		0.95	(0.95)
Costs to Serve Native Load	665.24	833.40	(168.16)
Costs to make Off-system Sales	130.45	99.82	30.63
Transmission System Operation Costs	1.84	0.82	1.02
Transmission Usage Costs	-	2.20	(2.20)
Legal, Regulatory & Transaction Costs		0.43	(0.43)
Total Costs	797.53	937.62	(140.09)
Revenues			
Transmission Revenues from OSS	19.58	4.18	15.40
Off-system Sales Revenue (MISO nets out Transmission Payments)	164.6	144.71	19.89
Total Revenues	184.18	148.89	35.29
Net Recurring Cost	613.35	788.73	(175.38)

As I discussed previously for the In MISO option, a correction, using MISO's own numbers, can be made to the MISO analysis to remove at least some of the impact of the erroneously included generation and to establish a lower bound on the extent of the bias in the TORC option as estimated by MISO. Mr. Sinclair also discusses these adjustments in his testimony. They involve removing the MWh and revenues for the WKE-leased BREC units from the LG&E/KU totals in the spreadsheets that MISO provided in the Response 54 Followup and adding back the MWh and revenues for the EEI and OVEC contractual capacity. However, when this was done, it became apparent that the relative impacts of the mistaken inclusion of this generation are not the same in the In MISO option and the TORC option. For example, OSS sales revenues drop from $164.6 million to $44.5 million, corresponding to 2.3 million MWh of OSS, which is no way consistent with the experience of the Companies' that historically is very much akin to a TORC scenario.

The adjustment made to the MISO analysis, using MISO's numbers, also increases power purchases in the TORC option from $0.9 million to $25.2 million and variable generation costs decrease from $599.7 million to $502.9 million. Whereas for the In MISO option, the adjustments that were made with MISO's own numbers brought the estimates much more in line with the Companies' estimates and historical experience, the attempt to correct for the impact of MISO's errors on the TORC option does not produce results that are at all consistent with what the Companies found in their own study and that would be consistent with historical experience. In fact, as MISO has already demonstrated in its own study, it had to make significant adjustments to the "conservative" hurdle rates in order to get the results of its simulated dispatch to match the Companies' historical experience. This is a sure sign that there are problems with the study, even if one did not know what the source of the errors were.

Q. Have the adjustments the Companies made with MISO's own numbers to the results of the MISO analysis managed to account for benefits that Dr. McNamara claims are due to the In MISO option?

A. Yes, in part, adjustments to both the In MISO and the TORC options that MISO simulated reduce the difference between the two options that MISO found initially and that contributes to the illusion that the In MISO option is to be preferred. Table 3 illustrates what happens to the dollar estimates for the In MISO and TORC options in three major categories – off-system sales, purchases and variable generation costs – when the erroneous units are eliminated and the contractual rights to the EEI and OVEC units are reinstated. Table 3 shows that under MISO's study, Off-system Sales, Purchases and Variable Generation Costs collectively make a contribution of $63.6 million to the recurring cost of the TORC option (refer to row 5 of Table 3). When the adjustments that I have described are made for errors in generation, as best as can be made under the circumstances, the collective contribution of these three categories drops to $47.5 million, a reduction of $16.1 million, which represents about 37% of the $43.9 million in net recurring cost of the TORC option that Dr. McNamara claims has been found in the MISO cost-benefit study. This reduction only illustrates the problems with the study. As I stated, the adjustments under the TORC option simply do not accord with historical experience, so that it is very likely that the adjustments that the Companies were able to make for the generation errors do not completely account for all of the problems these errors have caused in the analysis. The $16.1 million should be viewed as the lower bound.

Table 3 Effect of Adjustments for Erroneous Generation on MISO's Simulation of the In MISO and TORC Options ($ thousands)

	In MISO	TORC	Difference	In MISO Adjusted	TORC Adjusted	Difference	Effect of Adjustment
Off-System Sales Revenues	(265,464)	(164,572)	(159,548)	(105,916)	(44,475)	(120,097)	
Purchases Costs	1,047	883	12,809	13,856	25,170	24,287	
Variable Generation Costs	669,779	599,726	108,700	561,079	502,868	96,858	
Contribution to Net Recurring Cost of TORC Option			63,657			47,526	16,131

Q. How might the mistaken inclusion of this generation affect the LMPs used to calculate congestion costs?

A. The mistake of giving LG&E/KU financial rights to the output of at least 1,772 MW of generation, as I mentioned before, also affects the assignment of congestion costs to LG&E/KU. This is because the energy bids from those mistakenly included units will contribute to the hourly aggregate generation LMPs that are used to calculate congestions costs.

The energy bid curve corresponding to the "expected July 2005 supply curve" is significantly different when the erroneous generating units are eliminated. This is illustrated in Figure 1, which is based on the information provided by MISO in Response 28. The higher of the two bid curves represents the bid curve after eliminating the energy bids of the mistakenly included generating units. This shows how biases can arise in the LMPs for purposes of computing congestion costs in the In MISO option as well as for computing FTR revenues. I have not been able to assess the direction or the extent of these biases, however , I believe the impacts stemming from the generation errors I believe invalidates both estimates.

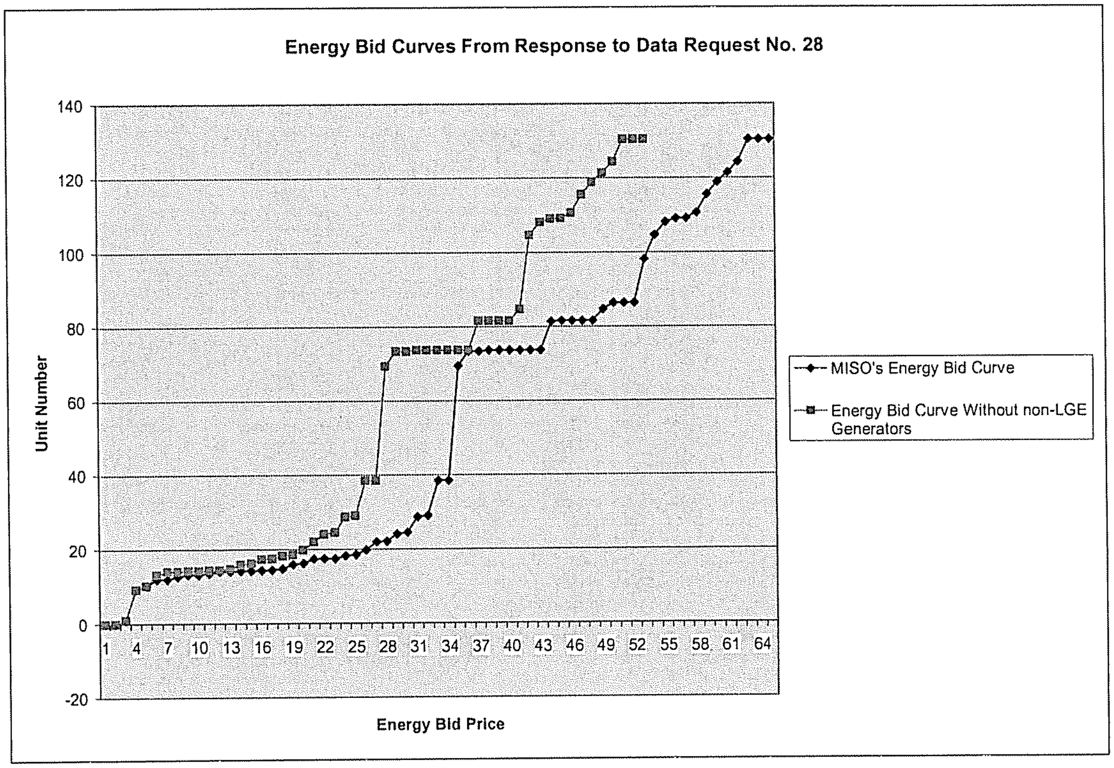


Figure 1 Energy Bid Curves for LG&E/KU With and Without Erroneous Units -- Based on Information Provided by MISO in Response 28

MISO's Cost-Benefit Study Suffers from Other Errors As Well

Q. Are there other errors that have been made in MISO's estimation of the costs and benefits of MISO membership?

A. Yes, I will mention one other error that I found in one of the spreadsheets that MISO provided as a work paper to support Dr. McNamara's testimony that is indicative of the many other errors in the study which has already been shown in my testimony to suffer at least two fatal flaws. The error bears on MISO's estimate of the congestion costs paid by retail customers. Dr. McNamara indicates on page 58, lines 20-21, that in the MISO's In MISO base case analysis, congestion costs totaled $35.2 million per year. However, the calculations in the spreadsheet intended to compute congestion costs mistakenly used figures that represented the dollar cost of off-system purchases when MWh of off-system purchases should have been used. Consequently, the congestion cost figure Dr. McNamara quotes in his testimony is incorrect. The actual figure is just over $37 million. I point this out merely to highlight the fact that the MISO cost-benefit study has many problems that tend to invalidate the results. The correction I have made should in no way be interpreted as an acceptance on my part of the corrected figure as providing any basis for estimating congestion costs for purposes of determining the costs and benefits of the In MISO option; as I stated earlier, there are simply too many critical deficiencies in the MISO's analysis.

FTR Values Are Unrealistically High and Based On a Logical Inconsistency

Q. How does Dr. McNamara arrive at the conclusion that the Companies could benefit from FTRs to the tune of $21 million per year.

A. The significant revenues that Dr. McNamara claims derive from FTRs allocated to the Companies' generating units appears to result from MISO's choice of the most valuable FTRs on the basis of the initial results of the simulation. To sift assets to keep those FTRs perceived as valuable and discard those FTRs that are liabilities would seem a realistic exercise, except for the fact that it is done in the MISO cost-benefit study from the vantage point of the end of the simulation, a use of "20-20" hindsight, and it ignores the initial objectives the Companies will be trying to achieve when they nominate FTRs in the EMT's four-tier process.

For the cost-benefit study, MISO cleverly chose only those FTRs allocated to generation units that produce positive FTR revenues for the Companies, and ignored a large percentage of those FTRs that produced negative revenues or, in other words, the FTRs that would have resulted in the Companies making payments to MISO. Had the full portfolio of FTRs been allotted and positive and negative revenues (i.e., payments to MISO) counted, the work papers that accompany MISO's cost-benefit study (refer to the spreadsheet Confidential-In-MISO_Total_Costs.xls) reveal that the Companies' FTR revenues would have only amounted to $11.3 million in the 2005 simulation. This would have resulted in leaving unhedged $24 million of the $35.2 million per year in congestion costs estimated by MISO.

The only way MISO knew what FTRs to ignore was the knowledge that certain FTRs created negative revenues within the simulation. The Companies will not be in a position to know ahead of time the actual financial impact of all of the FTRs nominated in the actual Day Two Market. While I believe the Companies' staff is quite capable of identifying the most valuable portfolio of FTRs to nominate, I believe that it is unrealistic to assume for purposes of evaluating the costs and benefits of a Day Two Market, that the Companies would be able to do better, even in the long run, than to manage to hedge a high percentage of the congestion costs.

I caution that this discussion of the FTR values should in no way be taken as an acceptance of or agreement with any of the values obtained by MISO in its study, since the congestion costs and the FTR values depend on the LMPs, which in turn depend on what units are dispatched and attributed to LG&E/KU for purposes of computing congestion costs. With over 1,700 MW of erroneous generating capacity dispatched within the MISO footprint and attributed to LG&E/KU when it should not be, it is anybody's guess at this point as to what the congestion costs and the FTR values should be for a correctly identified generation portfolio. The best estimates provided in this proceeding are those supplied by the Companies in their study.

Q. How was this portfolio of FTRs assigned to generating units arrived at initially?

A. The portfolio of FTRs that MISO used in the cost-benefit study was derived from a portfolio of FTRs that were initially proposed by the Companies to MISO for use in an illustrative example that MISO prepared at the request of the Federal Energy Regulatory Commission ("FERC") in early 2004. The FERC, in an order issued February 24, 2004, in Docket No. EL03-35-000, requested that MISO prepare an illustrative example of the FTR allocation process, and that an information filing be made at least 60 days prior to MISO's filing of the final market rules. MISO complied with this order by making an informational filing of illustrative FTR allocations on April 28, 2004.

The portfolio proposed by LG&E/KU, in an effort to cooperate with MISO in the construction of this illustrative example, was never intended for use in the context of a cost-benefit study. Because this was part of an illustrative example, the FTRs chosen were not developed as if the actual FTR nomination and allocation process that today has become a part of the EMT and the Day Two Market was in place. As MISO later admitted in filings to the FERC, the results of the illustrative example are not likely to be indicative of the results of the Day Two Markets because this illustrative example was based on the Companies' summer peak, did not account for differences in peak and off-peak usage, and there was no restoration process developed at the time of the illustrative example. I am certain that had the Companies known that this portfolio of FTRs was to be used in a cost-benefit study to demonstrate the benefits of MISO membership, they would have worked through an allocation that would reflect the realities of the nomination and allocation process.

MISO itself conditioned the results it submitted to the FERC by stating that they served only as a illustrative example of how the nomination and allocation method would work, not as a prediction of the resulting FTR allocations:

> ...as an illustration of the workings of the nomination and allocation methodology developed by the Midwest ISO and its stakeholders; however, the Midwest ISO emphasizes that the Illustrative FTRs are not intended to provide an indication of what will ultimately be the first year allocation of FTRs, for the reasons further explained in Section III.1 below. The Illustrative FTRs provide the [FERC]Commission and stakeholders with additional insight into the initial FTR distribution procedures. Because they did not arise from choices made by market participants, they do not have commercial or financial significance.[emphasis added]

These are strong cautionary words from MISO and I believe they should be heeded by the Kentucky Commission as it reviews the MISO cost-benefit study and the claims of Dr. McNamara based upon it.

Q. Could there be significant differences between the FTRs and FTR revenues obtained by MISO in the cost-benefit study and those obtained in the actual Day

Two Market?

A. Yes, there could be significant differences between both FTRs and FTR revenues obtained in the MISO study and what will happen when the Day Two Market opens. In other words, the FTR allocations made by MISO to LG&E/KU, which were made a part of the illustrative example filed at FERC and which were subsequently incorporated into the MISO's most recent cost-benefit study, may bear little or no resemblance to what might actually result from the FTR process now unfolding in preparation for the opening of the Day Two Market. In preparing the illustrative example, MISO did receive input on candidate FTR nominations from LG&E/KU. The Companies nominated 100% of the peak load or 6,667.2 MW of FTRs. In the illustration, the Companies received 6,126.3 MW of FTRs, about 92% of peak load. Mr Gallus, in his supplemental rebuttal testimony, discusses the Companies actual experience so far with the FTR allocation process.

Q. Are there other more fundamental problems with the FTRs in the MISO study?

A. Yes. Putting aside the fact that the FTRs were derived from an exercise totally unrelated to the cost-benefit study MISO conducted, there is a more fundamental problem with the FTR portfolio that MISO used, which is the logical inconsistency between the portfolio, which is based on generation units LG&E/KU do have financial rights to, and the generation units that have been credited with serving native load and making off-system sales, at least 1,700 MW of which LG&E/KU do not own or have financial rights to. The two sets of generators, as I have already discussed *ad nauseum*, do not match up.

When one considers how the Companies would go about nominating FTRs associated with generation that serves native load or that makes off-system sales, it would seem natural that they would consider all of the units that they had financial rights to or had rights to nominate FTRs for. This means that for the FTR portfolio to make logical sense in the context of the MISO cost-benefit study, either the FTR portfolio should be based on the units that MISO assumed LG&E/KU had financial rights to, or the units dispatched in the simulation to which LG&E/KU is given financial rights has to match those units that make up the FTR portfolio. MISO cannot mix and match from the two options. The results when one mixes and matches are uninterpretable. MISO has done precisely this, consequently one cannot make heads or tails of the outcomes of its analysis.

The best one can do in light of this unfortunate mistake is to assume that the congestion costs, whatever value those costs might take on, are completely hedged by the FTRs, even though it really is not possible to say with absolute certainty that that would be the outcome if the study had been conducted to ensure that it was logically consistent. This also illustrates why a study such as this one should be conducted with great care and has to be constructed in a thorough and logical manner.

MISO's Estimated Market Clearing Prices Are Unrealistically Low

Q. Do the market prices estimated in MISO's cost benefit study strike you as reasonable in light of the prices that can be observed in wholesale markets nationwide?

A. Absolutely not. MISO's estimate of market clearing prices for the LG&E/KU generation in the control area lie between $15 and $19 per MWh (refer to Exhibit RRM- Table 4) on average across the 2005 simulation year, depending on assumptions underlying the particular scenario. These estimates of market clearing prices are unrealistically low. David Sinclair discusses this in more detail in his rebuttal testimony.

Much of Dr. McNamara's Rebuttal Testimony Makes Generic Statements That Do Not Address the Key Question of Interest to the Commission

Q. What is the key question of interest to the Commission?

A. The key question that this Commission needs to determine the answer to is succinctly stated as: What are the *net* benefits of the Companies remaining within MISO relative to the *net* benefits of the Companies leaving MISO? It is not enough to look at *gross* benefits of either course of action without also looking at the costs of that course of action.

Q. Provide some examples of how Dr. McNamara's rebuttal testimony fails to address both the costs and benefits to Kentucky.

A. One example appears at page 3, lines 7-10, where Dr. McNamara makes a broad statement about the benefits that purportedly accrue to the entire region from regional coordination and dispatch. This overall statement about regional impacts ignores the fact that different market participants share differently in these benefits. Moreover, this conclusory statement about gross benefits provides no information about net benefits: namely whether regional security-constrained economic dispatch provides benefits to LG&E/KU that are large enough to offset the expected costs of participation in the Day Two Market.

Another example appears at page 3, lines 19-22, where Dr. McNamara says the question is whether MISO membership benefits Kentucky. But in fact the real question is whether the *net* benefit to Kentucky is positive, that is, the benefit after taking account of all expected costs. Dr. McNamara then states that to address the question he posed, one must examine whether the current practices of the Companies in dealing with real-time power flows through local dispatch is as reliable, precise, and efficient as it could be. Again, the proper way to address the question is to examine whether the costs of obtaining the incremental benefit of increased reliability through regional dispatch are larger than the benefit. The answer based on the Companies' well-supported analysis is yes, while MISO's flawed answer is no.

At page 7, lines 15-24. Dr. McNamara states that the Companies could not achieve the same reliability and regional coordination benefits under different arrangements such as a TORC option with reliability authority functions performed by another entity such as SPP or TVA. Again, even if this were the case, and Mr. Johnson's testimony states that it is not, the important issue is not merely whether MISO provides benefits, but whether the incremental benefits (if any) exceed the incremental costs. The Companies should attempt to achieve the necessary reliability and regional coordination benefits at the lowest possible cost. The Companies' system has up to this point been, and I have assumed it will continue to be, operated reliably and in accordance with all NERC standards. I agree that the Day Two

Market's centralized dispatch may enable operators to stay within operating security limits in a more economically efficient manner, but there is no justification for paying more for those efficiencies than they are worth.

Conclusions and Recommendations

Q. What conclusion have you reached about the MISO cost-benefit study?

A. My conclusion is that the MISO cost-benefit study suffers from significant errors that completely invalidate its results and the claims made by Dr. McNamara that are based on the study.

I have attempted to reconcile the results of the MISO study with the Companies' analysis, adjusting as much as possible for major errors made in the MISO study. According to Dr. McNamara, the net recurring cost of the TORC option is $43.9 million per year. However, adjustments can be made using MISO's own numbers to account for most of this amount. Table 5 summarizes this exercise.

Table 5 Summary of Adjustments to MISO's Estimate of the Net Recurring Cost of the TORC Option

	Net Recurring Cost of TORC Option – MISO Study	Net Recurring Cost of TORC Option After Adjustment
Original MISO Estimate	$43.9 million	
Adjustments		
Generation Errors	($16.1 million)	$27.8 million
Congestion Cost Error	($1.9 million)	$25.9 million
FTR Overstatement	($21 million)	$4.9 million

With just these three conservative adjustments to MISO's unrealistic estimate of the Net Recurring Cost of the TORC option, the $43.9 million is reduced to $4.9

million. Further explorations of the intimate details of the study would most likely reveal this $4.9 million is also illusory. Thus, the MISO results cannot be relied on in this proceeding. The direction that the adjustments has taken the MISO study leads it in the direction of the same conclusion that has been reached consistently by the Companies in all of its studies conducted in this proceeding, namely that the Companies and their customers will benefit more from moving to a TORC option than from continuing as MISO members subject to the costs and risks associated with the EMT and the Day Two Market.

At page 37, lines 9-20, Dr. McNamara states that the Companies' use of static models explains why the Companies' studies underestimate the benefit from a regional dispatch. He states that "the models used by the Companies are not capable of modeling how the network functions." Mr. Sinclair's testimony rebuts this point. Unfortunately, Dr. McNamara's models are not capable of correctly modeling the Companies' system so long as the inputs to the programs suffer from the kinds of errors that I have discussed.

Q. What is your recommendation to the Commission with regard to the MISO cost-benefit study?

A. I recommend that the Commission dismiss both the MISO cost-benefit study and the claims made by Dr. McNamara based on that study concerning the benefits of MISO membership.

Q. Does that conclude your testimony?

A. Yes.

VERIFICATION

STATE OF VIRGINIA)
) **SS:**
CITY OF ALEXANDRIA)

The undersigned, **Mathew J. Morey,** being duly sworn, deposes and says he is Senior Consultant, Laurits R. Christensen Associates, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

MATHEW J. MOREY

Subscribed and sworn to before me, a Notary Public in and before said State and City, this 06[TH] day of January 2005.

(SEAL)

Notary Public

OFFICIAL SEAL
EARL A. REID
Notary Public
COMMONWEALTH OF VIRGINIA
My Commission Expires
OCTOBER 31, 2008

My Commission Expires:

OCT 31, 2008

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP	)	
OF LOUISVILLE GAS AND ELECTRIC	)	
COMPANY AND KENTUCKY UTILITIES	)	CASE NO. 2003-00266
COMPANY IN THE MIDWEST INDEPENDENT	)	
TRANSMISSION SYSTEM OPERATOR, INC.	)	

SUPPLEMENTAL REBUTTAL TESTIMONY OF
SUSAN F. TIERNEY

ON BEHALF OF

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Filed: January 10, 2005

Q. Please state your name, position and business address.

A. My name is Susan F. Tierney. I am Managing Principal at The Analysis Group Inc. My business address is 111 Huntington Avenue, Boston, Massachusetts 02199. A statement of my qualifications was attached to my previously filed testimony in this case.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I have filed supplemental testimony before the Commission in this proceeding. That testimony was filed on behalf of Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU").

Q. What is the purpose of your supplemental rebuttal testimony?

A. My testimony rebuts some of the points made by Dr. Ronald McNamara in his Rebuttal Testimony, dated November 19, 2004, concerning regulatory policy issues.

Q. In his rebuttal testimony, Dr. McNamara asserts that "the authority of the Kentucky PSC to set rates for end-use customers is not in any way diminished" by LG&E/KU's participation in the Day 2 MISO Markets (page 2), and "the EMT does nothing to undermine how Kentucky (or any other state) sets retail rates or the terms and conditions of retail service" (page 6). Do you agree with Dr. McNamara on these points, as well as his statement that the "EMT will not cause the Kentucky PSC to lose regulatory control over any aspect of retail rates or retail service" (page 47)?

A. No. Based on my experience as a state rate regulator who set retail rates for companies that transacted in wholesale markets, it is clear to me that Dr. McNamara either is unaware of or misunderstands federal preemption, and its implications for the discretion of state regulators with regard to transactions covered by the Day 2 tariffs of MISO which are regulated by the Federal Energy Regulatory Commission ("FERC"). While I am not a lawyer and am not attempting to express a legal opinion on these matters, my direct regulatory experience leads me to disagree with Dr. McNamara on the cited statements he makes on pages 2, 6 and 47.

Of course, I agree literally with Dr. McNamara's point that under the Federal Power Act, FERC has jurisdiction over rates for electricity sold in interstate commerce and that this fact has not been changed by the establishment of the Day Two markets administered by the MISO. Where I disagree with Dr. McNamara is with regard to his assertion that the participation of a company like LG&E or KU in those Day Two Markets does not diminish or undermine "*in any way*" the ability of a state regulatory commission to set rates for retail service of such a company. My experience with regulatory retail rates in the context of federal preemption leads me to a different understanding – that is, that a state commission has no discretion as to whether to allow, as a reasonable operating expense, costs incurred as a result of paying a FERC-determined wholesale price. In my opinion, this fact, in combination with the way that transactions that will take place under the MISO Day 2 tariff, will lead to reduced scope of jurisdiction and discretion of the Kentucky PSC over certain matters currently under its rate-making authority.

Take, for example, a vertically integrated company with generation assets owned and used on behalf of its own retail customers. Let's assume that prior to participating in MISO Day Two markets, that electric utility used those same generating resources to supply its own load (i.e., self-supply), without a wholesale transaction involved. In this simple example, because there is no FERC-regulated sale of electricity, the state utility regulator would determine the terms and conditions under which those generating resources' costs were recoverable and recovered in retail rates. If, for example, the utility met an unexpectedly high level of retail demand in a particular hour through dispatching of its own resources, then that incremental generation for retail load would be under state rate regulation, since there was no wholesale sale of electricity involved. If, however, under the terms and conditions of participating in MISO Day Two markets, that electric company's higher-than-expected load beyond what was scheduled, were met with purchases from MISO's energy market, those wholesale purchases from the energy market would be undertaken pursuant to the FERC-approved MISO tariff, even if that load literally were met by MISO dispatching of that utility company's own generating resources.. In this latter case, it would be FERC and not the state regulatory commission that regulates the rates relating to the output of those power plants to meet the company's retail load.

Based on my experience, once electricity is bought and sold pursuant to a FERC-approved tariff, the state commission may not find those purchases to be unreasonable. The time the state can exercise discretion is the point at which a state authorizes a regulated company to participate in or decides not to allow the regulated utility to participate in the wholesale transaction. Once the state acts to allow participation in wholesale purchases, then the state must allow as reasonable the FERC-approved rate for such transactions. This is a material change in a state agency's discretion and authority when a situation where a utility's ability to supply its own load from its own generation (i.e., self-supply) that was once under state rate supervision becomes a FERC-regulated activity by virtue of the new wholesale purchase-and-sale of electricity transaction that arises.

Q. Do you agree with Dr. McNamara's assertions that one benefit of MISO participation is that the Kentucky Commission might have a meaningful role in development of future resource adequacy mechanisms, regional planning, and the allocation of regional expansion costs through the Organization of Midwest ISO States ("OMS"), given that FERC "...has made it clear that it is prepared to give deference to regional state committees (like OMS) on how best to design resource adequacy mechanisms" (pages 49-50) and further that "the Kentucky PSC will gain a forum – the Organization of Midwest ISO States – and a voice in the resolution of regional planning, reliability and grid expansion issues that it would not have but for the Midwest ISO" (page 7)?

A. No. In my opinion, Dr. McNamara overstates the incremental influence that Kentucky regulators will be able to wield over matters that are under the authority of the FERC. In my experience as a regulator in a region (New England) which has a history of relatively strong inter-state coordination and cooperation among state utility regulators, I cannot say that I have observed many clear examples where FERC, in practice, has given deference to the views of state commissions. And this is in a region with strong traditional interstate relationships specifically with regard to the activities of a FERC-regulated regional electric organization. Based on this experience, it makes me strongly question his assertion that Kentucky regulators, as one of many governmental and industry participants in regional resource adequacy or transmission planning discussions, could have a more meaningful role over the activities of MISO than Kentucky regulators have now in shaping the resource adequacy requirements of Kentucky utilities.

What I have observed as a regulator, a policy advisor and a consultant in many regions of the U.S. is that unless there is a high degree of consensus among state regulators on a matter affecting a regional grid operator, an Independent System Operator ("ISO") or a Regional Transmission Organization ("RTO") involving those states' electric utilities, state regulators' views come before the FERC like the views of any interested party, with no greater or lesser deference. I have observed further that even when there is high consensus among such state regulators, where these states disagree strongly with the positions of other key affected stakeholder groups, the FERC rarely gives deference to the states. From my experience, the instances – that is, the places – where a state has in practice had a "meaningful role" on the policies and activities of a FERC-regulated system operator have been in situations where there was a single-state ISO or RTO.

Q. On page 14, Dr. McNamara states "[t]he Kentucky PSC cannot know, and cannot get the information to determine, whether its utilities' local dispatches are truly least cost or whether they miss opportunities to purchase power from others at lower cost and miss opportunities to economic off-system sales to others." Do you agree with Dr. McNamara?

A. No. Based on my experience as a regulator and as a consultant, I believe that Dr. McNamara underestimates the ability of a state public utility commission to investigate matters under its jurisdiction, and in particular, matters relating to utility practices and rates under the jurisdiction of that agency. I do not mean to suggest that I have specific knowledge of the statutory provisions that would enable Kentucky regulators to carry out a particular investigation. But I do not interpret Dr. McNamara's point to be focused on Kentucky-specific statutory authorities. Rather, I believe his point is a more general one – that no state regulatory commission can adequately explore the details of interactions of a utility with wholesale markets in the absence of an RTO administering central markets. Based on my experience as a regulator and consultant, I believe that Dr. McNamara is either unaware of or understates the ability of a state regulatory commission to investigate, obtain information about and understand the practices of utilities under its jurisdiction.

Q. On page 68, Dr. McNamara states that the Companies have presented an overly simplified and "generation centric perspective" in this proceeding, and that for the "purposes of determining whether it makes sense for LG&E/KU to continue to have its transmission system managed by the Midwest ISO, it is necessary to see the Companies' position in the grid from a transmission operations perspective." He makes this statement in response to a question that suggests that your testimony "focuses on LG&E/KU being a low-cost utility." Do you agree with Dr. McNamara's characterization about what the focus of the Kentucky PSC should be on in this proceeding?

A. No. First of all, it is unclear what Dr. McNamara means by the phrase "generation centric." Second, if by that he means that Kentucky regulators should focus on transmission issues and ignore whether the retail consumers of LG&E/KU get the benefit of the low-cost generation supplies of LG&E/KU, then I disagree with his position. Certainly from the point of view of an RTO administering *wholesale* markets under

FERC regulation, it is understandable that Dr. McNamara would urge the Commission to focus its attention on transmission issues. But from the point of view of a state regulator, seeking to evaluate whether there are net benefits for the consumers of a state-jurisdictional utility of participating in a particular set of wholesale transactions, it is entirely appropriate to focus on all costs and benefits, including those relating to generation resources and retail consumer impacts, as well as reliability questions and transmission issues. This latter approach is not a matter of being "generation centric," but rather tailoring the object of attention to the state-jurisdictional interests at stake in this proceeding.

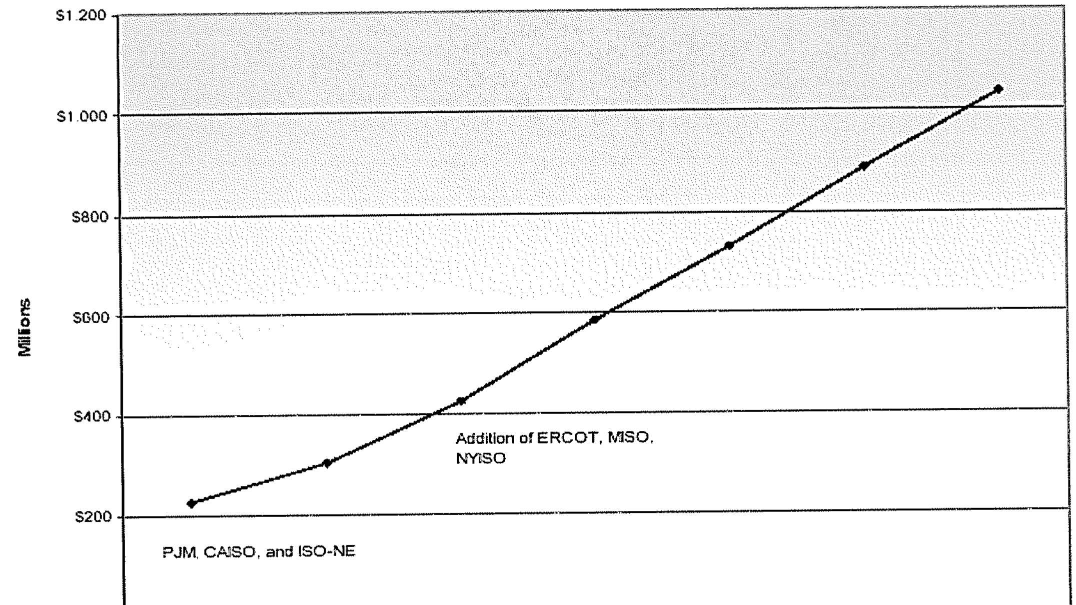
Q. In his rebuttal testimony, Dr. McNamara asserts that there are net benefits to the consumers of LG&E/KU of continued participation in MISO (see, e.g., pages 2 and 8-10). Without specifically addressing the merits of his benefit/cost analysis (which is the subject of other witnesses' supplemental rebuttal testimonies), are you aware of any studies of relevant trends in the RTO expenses for administering Day One and Day Two functions?

A. Yes. I am aware of a study prepared in August 2004 by Margot Lutzenhiser of the Public Power Council, in which she collected and tracked administrative costs and other data over time for various RTOs. The trends in these data show significant increases in administrative costs over time for all of the RTOs in her study, which includes data for Day One operations as well as well as for planning for and (in some cases) implementation of Day Two markets. I have included the key summary charts from this study in SFT Rebuttal Exhibit 1 to this supplemental rebuttal testimony.

Q. Does this conclude your testimony?

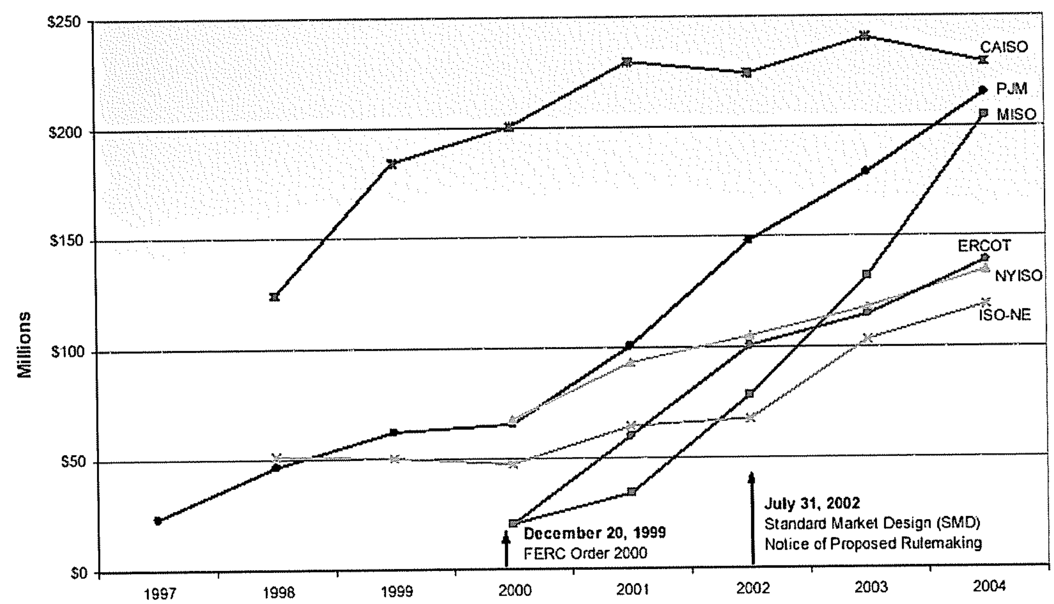
A. Yes, it does.

Annual U.S. RTO/ISO Operating Costs (2003 dollars)



	1998	1999	2000	2001	2002	2003	2004
RTO Expenses	$226,771,863	$302,836,246	$424,926,009	$584,279,480	$730,160,074	$885,701,442	$1.035.338.562

ISO/RTO Annual Operating Costs (Including Amortization, Depreciation and Interest Expenses in 2003 dollars)



Margot Lutzenhiser, "Comparative Analysis of RTO/ISO Operating Costs," Public Power Council, August 17, 2004, margotl@ppcpdx.org, page 4, http://www.ppcpdx.org/ComparativeAnalysisTWO.FINAL.pdf

VERIFICATION

STATE OF CALIFORNIA)
) SS:
COUNTY OF SAN BERNARDINO)

The undersigned, **Susan F. Tierney, Ph.D.**, being duly sworn, personally appeared before me, and says she is Managing Principal of the Analysis Group, that she has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and that the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Susan F. Tierney

SUSAN F. TIERNEY, Ph.D.

Subscribed and sworn to before me, a Notary Public in and before said State and County, this 4 day of January, 2005.

Theresa R. Alexandris (SEAL)

Notary Public

My commission expires:

Feb 7, 2007

THERESA R. ALEXANDRIS
Commission # 1398867
Notary Public - California
San Bernardino County
My Comm. Expires Feb 7, 2007

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	)))))	**CASE NO. 2003-00266**

SUPPLEMENTAL REBUTTAL TESTIMONY OF
MICHAEL S. BEER
VICE PRESIDENT, FEDERAL REGULATION AND POLICY
LG&E ENERGY LLC

Filed: January 10, 2005

Q. Please state your name, position and business address.

A. My name is Michael S. Beer. I am Vice President, Federal Regulation and Policy for LG&E Energy LLC, the parent company of Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU" or "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications was attached to my previously filed testimony in this case.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission in this proceeding and filed direct, rebuttal and supplemental testimony. I testified most recently before this Commission in the Companies' retail rate cases, Case Nos. 2003-00433 and 2003-00434. I have also testified before this Commission concerning regulatory policies in Case No. 2001-104, *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance With E.ON AG's Planned Acquisition of Powergen plc*, as well as in environmental surcharge proceedings on behalf of the Companies.

Q. What is the purpose of your testimony?

A. My testimony rebuts the assertions Dr. McNamara made in his Rebuttal Testimony of November 19, 2004, concerning rate and regulatory issues.

Q. Dr. McNamara states on page 48 line 19 of his rebuttal testimony that the Commission does not lose authority over retail rates under the EMT. Is this correct?

A. Yes, but this statement is misleading. On page 48, lines 22-24, Dr. McNamara states that if utilities "rarely use the spot market and rely primarily on their own resources to serve their own load, there could be little if any effect on retail rates." Yet Dr. McNamara does not state that there will be no effect on retail rates. Indeed, there will be an impact on the costs the Companies incur to serve native load customers, whether or not the Companies rely on the spot markets. There will be costs associated with the administration of the MISO markets. There will be uplift costs associated with activities that take place well beyond the Companies' footprint and activities. There will be costs and revenues associated with congestion and losses whether or not the Companies rely on their own resources to serve load. There will be the costs of any energy imbalance between Day Ahead schedules and real time uses of the system that will be settled automatically at real time spot market prices. All of these costs will invariably impact retail rates and, therefore, warrant inclusion in any cost of service study.

Q. On page 47 of his rebuttal testimony, Dr. McNamara asserts that the "EMT will not cause the Kentucky PSC to lose regulatory control over any aspect of retail rates or retail service." Do you agree?

A. No. The EMT effectively erodes the Commission's authority on several levels. First, it transforms aspects of what is presently retail service into wholesale transactions.[1] At present, the Companies generate power to serve native load customers. Such provision of power is effectively a retail transaction[2] which undoubtedly falls within the

[1] I discuss in greater detail below how MISO's Day 2 markets convert what are today retail transactions into wholesale transactions.

[2] The only transactions that do not fit perfectly the retail model are those subject to the PSSA between LG&E and KU.

Commission's jurisdiction. In Day 2, however, the Companies will offer[3] and sell their generation into the Midwest Independent Transmission System Operator, Inc.'s ("MISO") markets and, through completely unrelated transactions, the Companies will also purchase energy from MISO to serve their native load customers. Any connection between the Companies' generation fleet and their native load customers will exist only on the Companies' ledgers; MISO has stipulated that in the Day 2 market there simply will be no physical connection between the Companies' generation resources and their native load.[4] Thus, the Companies' method for meeting their obligation to provide highly reliable and cost-effective service to their native load customers will, therefore, change fundamentally when the Companies' currently retail transactions are essentially transformed into wholesale transactions in the Day 2 markets. It is this conversion from retail to wholesale that will deprive the Commission of some of its ability to regulate what used to be retail sales because it is the Federal Energy Regulatory Commission ("FERC"), not the Kentucky Commission, that has the authority to regulate the rates and conditions of wholesale energy transactions under the Federal Power Act.

What heightens our concern is that this erosion of the Commission's ability to regulate the components of what are currently retail rates comes with a potentially significant price tag as compared to the *status quo*. Although the transmission of power to serve native load is currently subject to the service terms and conditions of the MISO OATT, it is excluded from the transmission charges under the MISO OATT (other than a MISO Schedule 10 administrative charge), and additionally, the transactions are not subject to an energy, transmission congestion, or losses charge from MISO. In the Day 2

[3] "Offer" in this instance includes self-scheduled price taking offers, which as described in the stipulation are simply offers to sell power to the market at the market clearing price, as opposed to an offer to sell at a set price.
[4] Stipulation of the Companies and MISO ¶ 12.

market, these same transactions will be subject to MISO's scheme of locational marginal prices ("LMPs"), which include marginal energy, transmission congestion costs, and marginal losses components, as well as MISO charges for market administration.

The Companies recently filed an application with the Commission to seek recovery of these additional MISO-imposed costs. Although it is not certain what form the recovery will take, it is certain that these federally-approved charges will have some impact on retail rates. The Commission has not had, and will not have, the ability to prevent the Companies from incurring the increased costs that will be allocated or charged by MISO to the Companies for these additional market charges and energy, congestion and marginal losses charges, as well as uplift charges. Consequently, the impact on customer rates exemplifies yet another aspect of the Commission's loss of oversight should the Companies remain MISO members in the Day 2 market, notwithstanding Dr. McNamara's assertions to the contrary.

Furthermore, the Commission's present authority over the Companies' provision of service to their native load customers is impacted in additional ways. The Commission currently exercises broad authority over numerous aspects of the planning, operations and business of regulated utilities in the Commonwealth, including the authority to ensure the health, safety and welfare of the Companies' Kentucky native load customers who depend on the Companies for the generation and transmission of their electric energy. And the Commission's authority will be diminished by the Companies' continued participation in MISO's Day 2 markets by reason of the Independent Market Monitor's ("IMM") role in overseeing control or balancing area operations, which Mr. Gallus discusses in his testimony.

Q. Dr. McNamara states on page 48 line 15 of his rebuttal testimony that ". . . how utilities respond to the needs identified in the RTO planning exercise remains subject to state control." Do you agree?

A. Dr. McNamara's statement is misleading in that it implies that the *status quo* will continue. MISO's plan to offer a regional transmission ("RTO") planning process in which all parties must participate, as Dr. McNamara implies on page 48 lines 13-14, causes the Companies concern that there will be a significant change to the planning process. Specifically, as explained below, the Companies believe that the result of MISO's proposed regional planning process will be the imposition of costs determined thorough MISO's own resource plan onto Kentucky's planning process. Moreover, MISO's planning process will make determinations of cost based upon an *energy-centric* approach, without consideration of generation capacity concerns.

MISO's most recent proposal with regard to purely economic transmission upgrades would position MISO as the sole arbiter of when a transmission project offers the best market response to high LMP congestion costs. MISO also proposes to identify the beneficiaries of such a project and allocate project costs to those identified beneficiaries. Under this proposal, the market participants' roles would be reduced to negotiating and arbitrating any differences of opinion over the costs MISO has allocated among the identified beneficiaries.

Such economic transmission upgrades impact energy supply and are a major component of the state planning process. MISO's proposal would inject MISO into this process with the effect that MISO would have approval authority over the particular economic transmission resource(s) that would be integrated into the Companies' plan.

Moreover, because MISO plans to use energy prices,(*i.e.*, LMP differentials), as the basis for identifying economic upgrades, any transmission solution adds only throughput or enhanced access to energy supply, and does not by itself add supply capacity to the Companies' generation portfolio. Thus, these aspects of Day 2 demonstrate how MISO will effectively interpose its own resource plan into Kentucky's planning process based on its LMP energy model approach without regard to concerns about ensuring sufficient generation capacity in Kentucky.

Q. **With respect to the regional planning process, Dr. McNamara states on page 7, lines 3-4, that the Commission "will gain a forum – the Organization of MISO States ["OMS"] – and a voice in the resolution of regional planning, reliability, and grid expansion issues that it would not have but for" the MISO. Is this an accurate characterization?**

A Once again, Dr. McNamara's statement is misleading. Although the Commission has access to the OMS forum by virtue of the Companies' MISO membership, the Commission's role in the OMS is of relatively little value as compared to the Commission's current role as the sole regulatory voice and vote on planning, reliability, and grid expansion issues within the Commonwealth. Little, if any, benefit can be gained by diluting that full authority and providing the Commission a "voice" in the OMS – a voice that can be diluted by the collective voices of high-cost or retail choice states. Moreover, the Commission's "voice" in the OMS does not give the Commission a <u>vote</u> in regional planning: such authority is MISO's alone. Regional planning is a difficult challenge, and coordinating state efforts across the region through groups like the OMS can be useful; however, I do not agree that access to a multi-state venue such as the OMS should be characterized as a benefit available to the Commission that can be achieved only by virtue of the Companies' membership in MISO.

Moreover, the "voice" that the Commission gains through the OMS -- however effective or ineffective -- is not comparable to the Commission's own regulation of planning, reliability and grid expansion issues here in the Commonwealth. The Commission should be aware that it will indeed relinquish certain authority to MISO, OMS and FERC, at least over transmission planning, should it elect to order the Companies to remain in MISO.

Q. Dr. McNamara states on page 55, lines 3-14, of his rebuttal testimony that the MISO studies indicate that the Companies planned generation investment at Trimble County would in fact be more cost effective if located elsewhere on the LG&E/KU system. Do you agree?

A. Absolutely not. The MISO studies to which Dr. McNamara refers are based on optimization of projected LMPs. Importantly, Dr. McNamara ignores the fact that many factors should be considered when determining where to site new generation, rather than simply focusing forecasted LMPs. The additional variables that should be evaluated include the suitability of the land, proximity to fuel sources, availability of water, access to existing infrastructure and labor, interconnection and transmission costs, and feasibility of obtaining the necessary air permits, just to name a few.

Moreover, because the Companies determine where to build new generating units by analyzing the least-cost alternative to serve native load retail customers, the projected wholesale value of energy at proposed generator sites or at the Companies' aggregate load points has little if any effect on the economics of the project(s). The Companies' goal is to assure their native load retail customers of reliable, low-cost energy first, and only after that goal is achieved do the Companies consider how to maximize the customers' share of benefits that may be realized through off-system sales.

Dr. McNamara's LMP-based value maximization methodology is an entirely different approach that would dramatically change the Commission's and the Companies' current approach to generation siting. The Companies' current system of analyzing a proposed plant's revenue requirements would be replaced with an attempt to predict future LMPs. Future LMP value prediction is a very elusive exercise because LMP value is dependant on outside parties who will add factors such as transmission, generation, load growth or load management to the equation in a largely unpredictable fashion. Such an approach to generation siting, which essentially would involve siting new generators where they might be anticipated to lower LMPs in one area or capture high prices in another, is an exercise in market speculation. As state-regulated public utilities, the Companies' primary responsibility is to ensure reliable, low-cost capacity and energy are available for their native load retail customers, then to further optimize the value of LG&E/KU-owned assets for which their customers have paid on a cost basis. It seems counter to the Companies' traditional obligations to ensure adequate and reliable service to now redefine the cost to ratepayers of utility owned assets by continually assessing and re-assessing market value.

Q. Dr. McNamara states on page 49, line 6, of his rebuttal testimony that the EMT does not convert retail sales to wholesale transactions and thus make them subject to FERC authority. Is this correct?

A. No, it is not correctly stated. If the EMT did not convert retail transactions to wholesale transactions, thus making them subject to FERC jurisdiction, then the Companies' former retail activity – the provision of energy from its own units to its own load – would not be impacted in any way by the FERC-approved implementation of MISO's EMT. But because the EMT fundamentally changes the way the Companies provide service to their retail customers, it is incorrect to state that the EMT does not convert retail transactions to wholesale transactions.

Today, the Companies serve their native load by meeting demand with the Companies' generation. There is no middleman: the Companies sell their energy directly to their native load customers in unambiguously retail sales. In the "tomorrow" of the Day 2 market, however, a direct retail relationship will not exist between the Companies and their native load customers. Rather, MISO will purchase energy from generation scattered across the entire MISO footprint, both in the day-ahead and real-time markets, then sell energy to all loads across the entire MISO footprint.. The Companies will meet their obligation to serve native load under the Day 2 market regime, then, by purchasing adequate energy from MISO and selling it at retail to native load customers. The Companies will also sell their generation into the MISO markets, but through separate transactions.[5] In the Day 2 market, the Companies' generation will correspond with native load only on a ledger sheet.

[5] An analogy may be useful to help understand why the Companies' sales to, and purchases from, MISO will be wholesale transactions. If the Companies sold a certain amount of energy to Cinergy, there is no doubt that such a transaction would be a wholesale sale. If the Companies bought a certain amount of energy from Cinergy, there is no doubt that it would be a wholesale transaction. The question that MISO's Day 2 markets raise, as applied to this analogy, is whether the Companies can simultaneously transact wholesale sales and purchases with Cinergy, given that those sales and purchases are independent transactions that have their own terms and conditions. The unambiguous answer, the Companies submit, is yes, the Companies can simultaneously transact a wholesale sale and a wholesale purchase with the same counterparty.

Further, self-scheduling will not enable the Companies to maintain today's *status quo*. As explained in the Stipulation between the Companies and MISO, self-scheduling will not provide the Companies with a mechanism whereby the Companies may direct their generation to their native load.[6] Because there is no physical connection between self-scheduled supply and fixed demand -- only financial schedules connect the two – the EMT converts the Companies' retail transactions to serve native load into wholesale sales and purchases, and, as noted previously, this process will likely compromise the Commission's jurisdiction over at least some components of retail rates.

Q. Do you believe MISO's implementation of an LMP system with its attendant real-time price transparency will enhance the Commission's ability to guard against the situation Dr. McNamara describes at pages 9 and 14 of his rebuttal testimony, in which the Companies dispatch uneconomically in order to benefit a marketing affiliate?

A. No. Today the Commission has the authority to review utility dispatch and investigate any allegation of affiliate abuse. Transparent LMP prices will, at most, provide the Commission with a forensic benefit when it undertakes such an investigation, as the Commission is unlikely to be monitoring the Companies' and their affiliates' trading activities on a five-minute basis. In addition, the two alternatives to MISO membership identified by Mr. Morey as more cost effective, the Transmission Operator with Reliability Coordination ("TORC") and Southwest Power Pool ("SPP") options, each provide for similar price transparency. For example, in the case of the TORC option, the cost of the Companies' marginal unit could be compared with the MISO proxy price, and in the SPP case, SPP would be calculating and posting real-time prices.

[6] Stipulation of the Companies and MISO ¶ 12.

Moreover, as the Commission is well aware, the Companies engage in very few affiliate transactions, and the Commission has excellent oversight of the Companies' few affiliate transactions through the Companies' fuel clause proceedings before the Commission.

Q. On page 21 in footnote 15, Dr. McNamara references your supplemental testimony, in which you suggest that "[i]f MISO sought only to continue to supply reliability-enhancing services, the MISO's objectives and the Commission's policy would align . . .." Dr. McNamara goes on to state that MISO "has steadfastly adhered to this reliability/transmission emphasis" and then states reason why he believes this is so. Do you agree that MISO has adhered to its original mission?

A. No, and I believe there is increasing concern among all MISO stakeholders over both the MISO scope- and the process by which that scope is continually altered. On December 9, 2004, the MISO stakeholders, across all market sectors, rejected a slate of three candidates for the MISO Board. I believe this is a significant indication that MISO's change in emphasis has caused a loss of membership support.

Another indication that MISO has strayed from its "reliability/transmission emphasis" is set out at length in Mark Johnson's rebuttal testimony filed today; namely, that MISO is pursuing supposed economic efficiencies above all else, with no real regard for whether these efficiencies can, or will, have any measurable impact on the reliability of the grid.

Q. Dr. McNamara states on page 48 line 5 that the EMT does not undermine the Commission's authority over generation siting approvals. Is this correct?

A. Yet again, Dr. McNamara's statement is misleading. It is misleading because, although Kentucky retains the right to site generation pursuant to KRS 278.700, et seq., the MISO regional planning process establishes planning criteria that differ from those applicable to the Companies as established in state law. MISO must review and approve all new interconnections to the transmission system MISO operates, including the Companies' transmission system. MISO also establishes the allocation of costs between all the interconnecting generators that are studied and planned at a given time. Thus, MISO will wield significant influence over the Companies' siting plans for new generation because MISO's authority to allocate the costs of interconnections will affect the costs of siting a unit at one location versus another. Although this does not diminish the Commission's or the Siting Board's authority outright, it requires the Companies' plans to meet separate criteria for separate approving entities, which potentially makes it even more difficult for the Companies to site and construct generation needed to meet their obligation to serve.

Moreover, the public interest of Kentucky customers may not be well-served by MISO's de facto authority over new generation siting that results from its de jure authority over interconnection cost allocations under the EMT. Part of MISO's new de facto authority derives from LMP itself -- as Dr. McNamara demonstrated in his supplemental rebuttal testimony at page 55, MISO has already provided unsolicited advice to the Commission on where to site new generation based on how that generation and the required associated transmission will affect regional flows via LMP prices. The notion that the Commission should approve and site new generation based solely on how such generation will affect future regional power flows and prices is not only unrealistic, but is also antithetical to the Commission's role as guardian of the public interest of the

Companies' Kentucky customers. Although MISO will not be able legally to stymie the Commission's and Siting Board's actions, in the Day 2 market they will have the power to impose significant costs upon the Commission's and Siting Board's exercise of their rightful authority should the Commission and Siting Board choose to put Kentucky's needs above requirements of MISO's optimal regional power flow scheme.

Q. Do the Companies share Dr. McNamara's concern that SPP is a "nascent RTO" that offers in comparison to MISO only limited functionality?

A. No. The fact that FERC only recently recognized SPP as an RTO does not detract from SPP's long history as an efficient, well-run power pool.[7] Furthermore, the Companies' staff members have had opportunities to work together with SPP's staff members and have found them to be highly competent.

The Companies also take issue with Dr. McNamara's characterization of SPP as having "limited functionality" as compared to MISO. As Mr. Johnson has testified, SPP is a NERC-certified reliability coordinator, and its long history as a power pool and its competent staff give the Companies every reason to believe that SPP would be just as capable and competent as MISO at providing Day 1 functionality, which is the Companies' primary objective in seeking membership in an RTO. Far from seeing SPP's "limited functionality" (i.e., lack of Day 2-type markets with LMP and FTRs) as a detriment, the Companies see such "limited functionality" as a benefit of any potential SPP membership. That positive evaluation is reflected in the generally favorable cost-benefit ratio of SPP relative to MISO, as shown in Mr. Morey's testimony.

[7] The Companies assume that Dr. McNamara did not mean to suggest that SPP is a "nascent" RTO with respect to establishing Day 2-like markets, given that MISO has yet to achieve its own full market start-up.

Q. Do the Companies share Dr. McNamara's concern that SPP is a non-contiguous to the LG&E/KU system and thus there is no logical reason for LG&E/KU to be in SPP?

A. Mr. Johnson discusses the insignificance of any impacts that arise from the absence of physical interconnections between SPP and the Companies. I would like to discuss this same issue from a regulatory point of view.

Those states that comprise the SPP footprint are nearly all non-retail-access states, the small non-ERCOT portion of Texas being the exception. Transmission-owning members of SPP are all vertically integrated utilities subject to state regulatory regimes, nearly all of which have far more in common with Kentucky than the MISO states of Ohio, Michigan and Illinois. The Companies believe that much of the stakeholder discontent with MISO, as most recently demonstrated by stakeholders' rejection of MISO's slate of board candidates, can be traced to MISO's need to accommodate both retail-access and non-retail-access regimes, as well as high and low electricity cost states. From a regulatory perspective, therefore, SPP is far more "contiguous" with the Companies and Kentucky than is MISO.

Given the development of the Joint Operating Agreement between MISO and SPP, which establishes a seamless real-time energy marketplace among the RTOs, and given Mr. Johnson's testimony, in my view it is reasonable to rely on Mr. Morey's cost benefit analysis, which quite logically concludes that SPP is the superior alternative should FERC lawfully mandate RTO membership.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Michael S. Beer**, being duly sworn, deposes and says he is Vice President, Federal Regulation and Policy for LG&E Energy Services Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

MICHAEL S. BEER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of January 2005.

Tammy J. Elzy
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006