REQUEST:

38. At page 50, Dr. McNamara states that the Companies could not achieve the benefits of an RTO through an alternative described by the Companies. One of the alternatives the Companies considered -- in accordance with the Commission's Order – is the PJM RTO.

   a. Please provide a side-by-side list of the RTO services, as defined by Order Nos. 888, 889 and 2000, that PJM provides and MISO will provide as of March 1, 2005.

   b. With regard to any functions PJM is providing that MISO will not be providing as of March 1, 2005, please provide an estimate of the MISO's expected costs associated with providing those functions.

OBJECTION:

The Midwest ISO objects to Data Request 38(a) in that it calls for analyses or studies that have not been performed and requests a list of RTO services as defined in Order Nos. 888 and 889, which predate FERC precedent regarding RTO services.

RESPONSE:

b. There are no estimates of costs associated with services the Midwest ISO will not be providing as of March 1, 2005 (*i.e.,* the expected cost associated with a service the Midwest ISO is not providing would be zero).

Witness: Ronald McNamara

REQUEST:

39. At page 52, line 12-17, Dr. McNamara states that "There is no apparent logic for a Kentucky utility to be considering joining an RTO so far distant from its own transmission system and no apparent reason to believe that this arrangement could benefit Kentucky in any way."

a. Is MISO planning to negotiate a joint operating agreement that would address coordination of SPP's proposed real-time imbalance market with MISO's Day 2 real-time market?

b. Will MISO coordinate the operation of its real-time market with SPP's proposed real-time market?

RESPONSE:

a. Yes. Please see the executed SPP-Midwest ISO Joint Operating Agreement, and Congestion Management Plan, which were filed on December 2, 2004, by SPP in FERC Docket No. ER04-1096-002.

b. Please see the Midwest ISO's response to Data Request No. 39(a) above.

Witness: Ronald McNamara

REQUEST:

40. At page 53, line 14, Dr. McNamara states that he is using an expanded modeling analysis. Please identify the data used that resulted in each and every change between the expanded analysis and the initial modeling analysis (which is referenced at lines 8-9 on page 53), the reason for each change and please quantify the impact of each change.

OBJECTION:

This request is unduly burdensome, in that a separate quantification of the impact of each update and change would require a large number of additional model runs selectively changing individual inputs. Moreover, the model runs presented in Dr. McNamara's rebuttal testimony are based on a 2005 power flow case that was not available at the time his initial testimony was filed approximately one year ago. As a result, it would be very difficult to develop meaningful single element comparisons. Without waiving its objection, the Midwest ISO responds as follows.

RESPONSE:

For identification of the individual changes, please see the rebuttal testimony of Dr. McNamara at pp. 69-70. The reasons for making these changes were to reflect the approval of and FERC ordered changes in the implementation of the Midwest ISO Energy Markets Tariff, update the study to reflect more recent information that was unavailable at the time of the original study, and expand the analysis to incorporate a broad range of sensitivity analyses.

Witness: Ronald McNamara

REQUEST:

41. At page 55, lines 6-10, Dr. McNamara states that MISO's "modeling suggests operating additional generating capacity at the Trimble County site may in some circumstances further constrain transmission, limit regional power flows, and be more costly than locating generation in other portions of the LG&E/KU system." Please describe the basis and provide all data, methodology and supporting analyses used for this assertion.

RESPONSE:

See the rebuttal testimony of Dr. McNamara at p. 55 and Appendix B, as well as the spreadsheet "Locational Value.xls" provided in the workpapers supporting that testimony (on a CD-ROM sent December 15, 2004).

Witness: Ronald McNamara

REQUEST:

42. Please reference page 55, lines 6 *et seq*. Were any transmission upgrades identified and approved by MISO for Trimble County 2 included in the modeling conducted for the cost-benefit study?

RESPONSE:

Upgrades to the transmission capacity from the Trimble County bus to Middletown and the Middletown bus to Buckner were included in the modeling for the benefit-cost analysis.

Witness: Ronald McNamara

REQUEST:

43. (Page 55, Line 23-25) Please provide all data, quantifications and a description of the methodology used to support the assertion that there will be "significant negative reliability impacts on LGE/KU customers" if LG&E/KU were to withdraw from the MISO.

RESPONSE:

Please see the direct testimony of Mr. Harszy, Dr. Falk, and Dr. McNamara in this proceeding; the rebuttal testimony of Dr. McNamara at pp. 37 – 40 and 55; and Dr. McNamara's affidavit, which was filed in FERC Docket Nos. ER04-691-000 and EL04-104-000, which is available at the FERC website at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10176978

Witness: Ronald McNamara

REQUEST:

44. With reference to page 57, lines 14 *et seq.*, please provide any quantifiable data in electronic format (e.g., Excel spreadsheets) other than the cost-benefit study performed by MISO to support the assertion that "the presence of a large, efficient regional market adjacent to LG&E/KU will tend to depress prices for LG&E/KU generation in comparison to both current prices and the prices available to LG&E/KU as members of the Midwest ISO."

RESPONSE:

For a comparison of forecasted hourly prices, given the current approach to transmission operations under the TORC option and remaining in the Midwest ISO, see the workpapers and data filed in support of Dr. McNamara's testimony, particularly the following Excel spreadsheets on the CD-ROM sent on December 15, 2004:

- Day 1 Total Costs.xls
- Day 1 High Fuel Cost.xls
- Day 1 Low Fuel Costs.xls
- Out of MISO Total Costs.xls
- Out of MISO High Fuel Cost.xls
- Out of MISO Low Fuel Costs.xls
- In MISO Total Costs.xls
- In MISO High Fuel Costs.xls
- In MISO Low Fuel Costs.xls

Witness: Ronald McNamara

REQUEST:

45. With reference to page 58, lines 6 *et seq.*, please provide any data in electronic format (e.g., Excel spreadsheets) to support the assertion that LG&E/KU transmission revenues will not decrease in light of the elimination of the regional through-and-out rate in MISO and PJM and the likely reduction in use of PTP transmission within the MISO upon the start of the Day 2 market.

RESPONSE:

See the rebuttal testimony of Dr. McNamara at p. 58, footnote 30, and the spreadsheet entitled "Transmission Revenue.xls," which was included in the workpapers provided in support of this testimony on a CD-ROM sent December 15, 2004. Given the presence of both factors that might tend to decrease and other factors that will tend to increase distributions of transmission revenue to LG&E/KU, actual distribution over the last 12 months represents a reasonable and the best available indicator of future transmission revenue distributions to LG&E/KU.

Witness: Ronald McNamara

REQUEST:

46. At page 66, lines 7-17, Dr. McNamara states that he identified a "frequently occurring pattern in the location specific prices for the LG&E/KU system" that showed "prices at the Trimble County facility were often lower than LG&E/KU generating sites downstream ..." Please describe the basis and provide all data, methodologies and supporting analyses used for the assertion that a savings of nearly $1 million per year could be achieved if the combustion turbines were placed at the Ghent plant site rather than at Trimble County.

RESPONSE:

See the Midwest ISO response to Request No. 41. See also the workpapers related to individual model runs provided, on a CD-ROM sent December 15, 2004, in support of Dr. McNamara's testimony.

Witness: Ronald McNamara

REQUEST:

47. With reference to page 70, lines 1-3, please provide data in electronic format (e.g., Excel spreadsheets) on the four tier illustrative FTR allocation results, including without limitation, the percent of peak load FTR that was nominated by each MISO market participant.

    a. Did all market participants provide input in the mock allocation?

    b. What assumptions were made for market participants that did not provide input in the mock allocation?

RESPONSE:

See the Midwest ISO's information filing, submitted to the FERC on April 28, 2004, in Docket Nos. ER04-691-000 and EL04-104-000. This filing is available at the FERC web site, at http://elibrary.ferc.gov/idmws/File_list.asp?document_id=4199437.

Witness: Ronald McNamara

REQUEST:

48. At page 71, lines 13-15, Dr. McNamara states that "There is no reason to believe that the difference between the cost to serve load under the TORC option and in the Midwest ISO will change materially over the period 2005-2010." Please provide all data, methodologies and supporting analyses used for this assertion.

RESPONSE:

Dr. McNamara's conclusion is supported by the following:

1. The difference in the cost to serve load under the TORC and Midwest ISO options described in his testimony was based on a conservative set of parameters designed to understate the costs of LG&E/KU leaving the Midwest ISO. Given that the initial analysis was specified in a conservative manner, year-to-year changes in individual inputs would have to accumulate in a consistently unfavorable direction over a period of time before they would impact the direction of the study's conclusion that leaving the Midwest ISO would significantly increase the cost to serve LG&E/KU native load. See Dr. McNamara's rebuttal testimony.

2. The study included extensive sensitivity analyses, which indicated that the cost to serve load under the TORC option would be significantly higher than the costs associated with Midwest ISO membership under a wide range of assumed futures. Thus, even if subsequent years introduced factors that were unfavorable to Midwest ISO membership, the sensitivity analysis suggests that such factors are unlikely to change the overall conclusion that the TORC option significantly increases the cost to serve LG&E/KU native load. See Dr. McNamara's rebuttal testimony.

3. The benefits of Midwest ISO membership quantified in the modeling analysis include only near-term benefits of centralized dispatch and improved access to regional markets. The intermediate and longer-term benefits of Midwest ISO

Witness: Ronald McNamara

membership could be much larger than the near-term benefits, which have been modeled for 2005. The statement that "there is no reason to believe the difference in the cost to serve load under the TORC option and in the Midwest ISO will change materially…" is, in part, a conservative conclusion that regardless of how the modeled effects may change over as time goes on, intermediate and longer-term benefits of price transparency, improved incentives, and enhanced regulatory oversight are large and will become increasingly important over time. See Direct Testimony of Dr. McNamara at Exhibit RRM-1, pp. 14-16, and Dr. McNamara's rebuttal testimony.

4. Other studies that have quantified savings for the ECAR region associated with the implementation of regional wholesale markets and regional security-constrained economic unit commitment and dispatch have identified modest increases in the levels of projected regional cost savings through at least 2010. See U. S. Department of Energy, *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (April 30, 2003) and ICF Consulting, *Economic Assessment of RTO Policy* (February 26, 2002). Although these studies are not specific to LG&E/KU and the Midwest ISO Energy Markets Tariff, they are consistent with the conclusion that the benefits of RTO membership are unlikely to materially decline over the period 2005–2010. These studies are voluminous. They are provided on the accompanying CD-ROM as three PDF files:
    - Attach_48 - ICF Consulting Report.pdf
    - Attach_48 - DOE Report.pdf
    - Attach_48 - DOE Report Appdxs.pdf

5. The PROMOD analysis of the cost differential between the TORC option and continuing Midwest ISO membership in Dr. McNamara's testimony was based on the best available economic forecasts. These forecasts are believed to be

representative of what can be expected to occur in near to intermediate time horizons.

6. It is the Midwest ISO's understanding based on the LG&E/KU 2002 Integrated Resource Plan that the Companies do not intend to add base load generating capacity before 2010. See Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company. Thus, the mix of generators operating during most hours of the year is unlikely to change materially prior to 2010.

Witness: Ronald McNamara

REQUEST:

48. At page 71, lines 13-15, Dr. McNamara states that "There is no reason to believe that the difference between the cost to serve load under the TORC option and in the Midwest ISO will change materially over the period 2005-2010." Please provide all data, methodologies and supporting analyses used for this assertion.

RESPONSE:

Dr. McNamara's statement is supported by the following:

1. The difference in the cost to serve load under the TORC and Midwest ISO options described in his testimony was based on a conservative set of parameters that may understate the costs of LG&E/KU leaving the Midwest ISO. Given that the initial analysis was specified in a conservative manner, year-to-year changes in individual inputs would have to accumulate in a consistently unfavorable direction over a period of time before they would impact the direction of the study's conclusion that leaving the Midwest ISO would significantly increase the cost to serve LG&E/KU native load. See Dr. McNamara's rebuttal testimony.

2. The study included extensive sensitivity analyses, which indicated that the cost to serve load under the TORC option would be significantly higher than the costs associated with Midwest ISO membership under a wide range of assumed futures. Thus, even if subsequent years introduced factors that were unfavorable to Midwest ISO membership, the sensitivity analysis suggests that such factors are unlikely to change the overall conclusion that the TORC option significantly increases the cost to serve LG&E/KU native load. See Dr. McNamara's rebuttal testimony.

3. The benefits of Midwest ISO membership quantified in the modeling analysis include only near-term benefits of centralized dispatch and improved access to regional markets. The intermediate and longer-term benefits of Midwest ISO

membership could be much larger than the near-term benefits, which have been modeled for 2005. The statement that "there is no reason to believe the difference in the cost to serve load under the TORC option and in the Midwest ISO will change materially…" is, in part, a conservative conclusion that regardless of how the modeled effects may change over as time goes on, intermediate and longer-term benefits of price transparency, improved incentives, and enhanced regulatory oversight are large and will become increasingly important over time. See Direct Testimony of Dr. McNamara at Exhibit RRM-1, pp. 14-16, and Dr. McNamara's rebuttal testimony.

4. Other studies quantifying savings for the ECAR region associated with the implementation of regional wholesale markets and regional security-constrained economic unit commitment and dispatch have identified increases in the levels of projected regional cost savings through at least 2010. See U. S. Department of Energy, *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (April 30, 2003) and ICF Consulting, *Economic Assessment of RTO Policy* (February 26, 2002). Although these studies are not specific to LG&E/KU and the Midwest ISO Energy Markets Tariff, they are consistent with the conclusion that the benefits of RTO membership are unlikely to materially decline over the period 2005–2010. These studies are voluminous. They are provided on the accompanying CD-ROM as three PDF files:

   - Attach_48 - ICF Consulting Report.pdf
   - Attach_48 - DOE Report.pdf
   - Attach_48 - DOE Report Appdxs.pdf

5. The PROMOD analysis of the cost differential between the TORC option and continuing Midwest ISO membership in Dr. McNamara's testimony was based on the best available economic forecasts. These forecasts are believed to be

representative of what can be expected to occur in both near and intermediate time horizons.

6. It is the Midwest ISO's understanding based on the LG&E/KU 2002 Integrated Resource Plan that the Companies do not intend to add base load generating capacity before 2010. See Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company. Thus, the mix of LG&E/KU generators operating during most hours of the year is unlikely to change materially prior to 2010.

Witness: Ronald McNamara

REQUEST:

49. At page 73, line 12 *et seq.*, Dr. McNamara describes how he developed the hurdle rates used in his analyses. Please provide a table that summarizes the hurdle rate assumptions and values for all cases in his analyses.

RESPONSE:

See the Excel spreadsheet entitled "Pools and Hurdle Rates.xls," which was provided in the workpapers supporting Dr. McNamara's rebuttal testimony, on the CD-ROM sent on December 15, 2004.

Witness: Ronald McNamara

REQUEST:

50. With reference to page 73, lines 1-2, please provide the data in electronic format (e.g., Excel spreadsheets) to support the 9% reduction in LG&E/KU flowgate capacities.

RESPONSE:

See the Excel spreadsheet entitled "TLR Analysis & FG Utilization.xls," which was provided in the workpapers supporting Dr. McNamara's rebuttal testimony, on a CD-ROM sent December 15, 2004.

Witness: Ronald McNamara

REQUEST:

51. At page 84, lines 16-20, Dr. McNamara states that "Mr. Gallus' assumption that he is identifying all cost effective transactions is simply wrong."

a. Please provide all empirical data in MISO's possession that supports MISO's claim that Mr. Gallus' assumption is wrong.

b. Please provide all empirical data in MISO's possession that supports MISO's claim that the Companies could be making twice the volume of cost effective off-system sales that they have been making in recent years.

OBJECTION:

This request is overly broad and unduly burdensome to the extent it requests potentially voluminous information, extends to third-party propriety information about scheduled transactions, requests details about specific schedules, could cover detailed data about actual power flows, and potentially includes all data in the Midwest ISO's possession whether or not it was directly involved in forming the basis Dr. McNamara's conclusions. Without waiving its objections, the Midwest ISO responds as follows.

RESPONSE:

Dr. McNamara's statement is supported by the following:

1. In the absence of regional security-constrained economic unit commitment and dispatch, there are opportunities to make cost-effective transactions that LG&E/KU is never in a position to observe. Why LG&E/KU cannot observe economic opportunities is described in greater detail in Dr. McNamara's direct testimony at pp. 8-18 and in his rebuttal testimony at pp.71-77 and 83-84. One factor is that in the absence of real-time security constrained economic dispatch, LG&E/KU has to rely on inherently imprecise posted forecasts of Available Flowgate Capacity (AFC) to reserve and schedule transmission service. Despite improvements that had been made

in the methodology for determining AFC, there have been instances in which actual flows did not match flows forecasted for purposes of posted AFCs resulting in unused flowgate capacity during hours in which forecasts posted to the OASIS system showed no additional transmission capacity was available. The attached spreadsheet, "Actual AFC by Flowgate.xls," summarizes the findings of an after-the-fact analysis based on actual power flows (and post-contingency flows calculated from actual flow data) of the capacity available on a subset of LG&E/KU flowgates during hours in September, October, and November 2003 when posted AFCs were zero.

2. When transmission capacity is constrained, in the absence of regional security-constrained economic dispatch, congestion is managed through an imprecise and inefficient TLR mechanism. As a result, transmission capacity is underutilized during periods of high demand. An analysis of all Midwest ISO TLR events occurring in 2003 for which data was available is presented in the spreadsheet "TLR Analysis & FG Utilization.xls" in the workpapers supporting Dr. McNamara's rebuttal testimony, on a CD-ROM sent December 15, 2004.

3. No individual utility or third-party broker is able to observe in close to real time a full regional set of bids and power flows so as to be able to optimize the dispatch of generation in light of power flows and transmission constraints. This is reflected in part in the economic inefficiency of relying on TLRs to manage congestion. Analyses of the inefficiencies of relying on TLRs and on transmission contracts that are not fully integrated with regional economic dispatch are discussed in the June 2004 affidavits of Dr. Ronald McNamara and Dr. David Patton in FERC Docket No. EL04-104-000.

4. In the absence of real-time regional economic dispatch, LG&E/KU are limited (with potential exceptions for purchases and sales within their control area and any dynamic schedules) to scheduling purchases and sales of energy in one-hour or longer strips.

Witness: Ronald McNamara

By contrast, security-constrained economic dispatch under the Energy Markets Tariff will identify and implement cost-effective power transfers at least once every five minutes.

These factors explain a significant portion, but not all of LG&E/KU's inability to identify all cost-effective transactions. Dr. McNamara is familiar with real world constraints on identifying bilateral trading opportunities. See Dr. McNamara's rebuttal testimony at Appendix C, pp. 4-5.

Furthermore, the conservative modeling analysis presented in Dr. McNamara's testimony identified a significantly higher volume of off-system sales opportunities than what LG&E/KU has historically achieved. See the workpapers supporting Dr. McNamara's rebuttal testimony, on a CD-ROM sent December 15, 2004.

Witness: Ronald McNamara

Average Actual ATC for LG&E Flowgates

NERC ID	Type	OASIS Pathcode	Average Actual ATC MW	Average Flow Magnitude MW*	Average MW Limit	# Hours Analyzed	# Intervals Anayzed	% of Capacity Available during Zero AFC Hours
2196	PTDF	BLUXFM__PTDF	65.87	179.20	245.06	179	15,327	26.88%
2198	OTDF	BLUXFMBAKBRO	56.91	188.82	245.73	511	46,102	23.16%
2201	PTDF	BRNFWK__PTDF	71.46	120.69	192.15	116	10,484	37.19%
2210	OTDF	KNBPNDBAKBRO	103.69	120.91	224.61	280	23,409	46.17%
2267	OTDF	KENWEDSPUMAY	164.94	19.84	184.79	285	25,422	89.26%
2279	OTDF	PDWPDRCR6___	118.38	251.62	370.00	122	10,580	31.99%
2484	OTDF	CLFNSICLFTRM	104.89	47.31	152.20	35	3,033	68.91%
2488	OTDF	BLUBULGHEWLX	50.76	188.24	239.00	243	22,436	21.24%

Notes: * The average flow magnitude MW is calculated from the Actual MW for PTDF flowgates and Contingency MW for OTDF flowgates.

The average values for a given hour and flowgate were calculated as a straight average of the available interval values within that hour for that flowgate. Any hour with fewer than 12 interval observations for the flowgate was excluded.

This analysis includes only those hours with zero AFC for the given flowgate.

Any hour for a given flowgate with an average flow magnitude MW greater than the average MW limit was excluded from the analysis.

12/9/03

REQUEST:

52. With reference to page 85, lines 10-15, if LG&E/KU remained a MISO member, would LG&E/KU no longer experience loop flows from Big Rivers, EKPC, or TVA for which LG&E/KU receive no compensation?

RESPONSE:

The referenced passage of Dr. McNamara's testimony addresses the fact that Midwest ISO membership will expand the number of transactions for which LG&E will receive transmission revenues. Within the Midwest ISO, LG&E will benefit from the distribution transmission revenues from point-to-point transmission service using any Midwest ISO operated transmission facilities. Under the TORC option, transmission customers will have the ability to select a contract path for point-to-point service and no incentive to include LG&E/KU on that path, such that expected LG&E/KU transmission revenue largely would be limited to revenues associated with power sales sourcing the LG&E/KU transmission system. Thus, if LG&E/KU remain in the Midwest ISO, there would be fewer circumstances in which LG&E/KU would experience loop flows without receiving compensation as a result transactions involving Big Rivers, EKPC, or TVA.

Witness: Ronald McNamara

REQUEST:

53. Please refer to Section VII, pages 53-89 of Dr. McNamara's testimony. Please provide all data, work papers and any other supporting documents that were used by Dr. McNamara or by any persons that Dr. McNamara supervised in the preparation of the cost-benefit study for which Dr. McNamara provides testimony in this proceeding. Please provide all electronic files, such as Excel Spreadsheets, Access Databases, CSV files (i.e., test files) and files that are the product of any computer software programs that were used in the conduct of the study about which Dr. McNamara testifies.

OBJECTION:

This request is unduly burdensome in that, in addition to the more than 65MB of electronic files included in the workpapers supporting Dr. McNamara's rebuttal testimony that already have been provided to the Commission and parties in this proceeding (in a CD-ROM sent December 15, 2004), it seeks a voluminous amount of data and other documents. The Midwest ISO estimates that if all original source data is considered this request could conceivably cover over a million data points. Moreover, some of the requested information is confidential and proprietary. Without waiving its objections, the Midwest ISO responds as follows:

RESPONSE:

In subsequent communications, counsel for LG&E/KU has identified data of particular interest to the Companies as indicated below. The Companies have indicated a specific interest in:

1. Files associated with two options — the base case (LG&E/KU in the Midwest ISO) and "TORC" (LG&E/KU out of the Midwest ISO) options — that contain the following information generated by the PROMOD IV analysis:
   - Hourly generation (in MW) by generation unit (by named unit);

- Hourly LMP ($ per MWh) by generation unit (i.e., bus);
- Marginal Congestion Cost ($ per MWh) by generation unit (i.e., bus); and
- Marginal Loss Costs ($ per MWh) by generation unit (i.e., bus).

2. Information used in the PROMOD IV aspects of the Midwest ISO's supplemental cost/benefit analysis:
   - The ".xml" PowerBase scenarios;
   - A copy of the "Event" files used in PROMOD IV;
   - Specific Generator Names/Buses used to calculate Generation Cost/Revenues; and
   - Model Diagnostic Reports specific to LGE/KU generation reflecting totals that tie to Midwest ISO results.

Where such data is available, and the Midwest ISO has authority to provide this information, it will do so as follows:

The information that the Midwest ISO has related to the first request for hourly generation, hourly LMP, and hourly LMP component data by unit or bus is contained in our files for each of the model runs that make up the study filed in Dr. McNamara's rebuttal testimony. These files were generated by turning on the reporting of designated outputs for selected buses and generating units prior to initiating each model run. Following the completion of any model run, such data was captured by the program and is available for only those generating units and buses for which reporting was turned on prior to initiating the run. Comparable data for other buses and generating units in addition to those selected prior to the initiation of each run is not available. Each of the files in question is quite large. These files are not available in either Excel or Access formats; the size of each of the files actually exceeds the size limitations of the Excel program. The data is available and will only be provided in a comma-delimited text format. The files provided, for the In MISO Total Costs and Out of MISO Total Costs model runs, are included on the accompanying CD-ROM; the component files for each of these model runs are condensed together into a .zip file.

With respect to the third item of the second request, a file with the Generator Names used in the analysis, "Unit Names.xls", is provided on the accompanying CD-ROM.

PROMOD IV produces Model Diagnostic Reports when specific diagnostic reporting functions are turned on prior to the initiation of a PROMOD model run. Reports that are not selected and reports for periods that are not designated prior to the initiation of a model run are not available. PROMOD Model Diagnostic Reports can add significantly to model run times and in running models of this size are used on a selective basis often for selected hours. Based on a review of the Model Diagnostic Reports available on the modeling runs for which results are presented in Dr. McNamara's rebuttal testimony, there are no available PROMOD Model Diagnostic Reports that are specific to LG&E/KU generation and reflect either the monthly or annual generation totals that tie to the results presented in that testimony.

Any ".xml" PowerBase scenarios or event files, as well as PROMOD Model Diagnostic Reports are or contain software products and data that are proprietary to New Energy Associates. The Midwest ISO does not have authority to provide to others such proprietary commercial software and data that is the intellectual property of New Energy Associates. LG&E/KU and other parties are free to license such products from New Energy Associates. It is the Midwest ISO's understanding that LG&E/KU have signed a license agreement with New Energy Associates for PROMOD and PowerBase, and that this agreement includes a unilateral cancellation clause that expires on December 31, 2004. Until the expiration of the unilateral cancellation period, the Midwest ISO understands that the existing agreement between LG&E/KU and New Energy Associates does not entitle LG&E/KU to obtain this information. Thus, the Midwest ISO cannot provide the requested ".xml PowerBase scenarios" or event files at this time.

Witness: Ronald McNamara

REQUEST:

54. Please provide on disk all Microsoft Excel files, Microsoft Access files or other formats associated with or that form the basis for the tables attached to Dr. McNamara's testimony.

RESPONSE:

See the workpapers provided in support of Dr. McNamara's rebuttal testimony, sent December 15, 2004, on a CD-ROM.

Witness: Ronald McNamara

REQUEST:

55. During the period in which it conducted its cost benefit analysis, did MISO consult directly with the Companies regarding the data inputs, assumptions or other aspects of modeling that were included in the MISO cost benefit analysis that pertained directly to the LG&E/KU system (generation facilities or transmission assets)? If yes, please provide the dates of those consultations, the persons contacted and a list of the information or copies of the information for which MISO sought consultation on.

OBJECTION:

This request is unduly burdensome to the extent it requires the Midwest ISO to identify contacts that were made and data that it sought and obtained for initial purposes other than directly to support benefit-cost studies in this proceeding. On a continuing basis, the Midwest ISO obtains information from its members, including LG&E/KU, on subjects related to transmission system operations, transmission service reservations and scheduling, settlements, transmission planning, market readiness, FTR nominations, and other subjects. Some of this information may have been included in the Midwest ISO data sets used for purposes of the benefit-cost analysis. It would be unduly burdensome to require the Midwest ISO to identify all such contacts with LG&E/KU personnel and to in effect construct an audit trail to communications with specific LG&E/KU personnel for each of the numerous data elements that might have been affected by such communications. Without waiving its objections, the Midwest ISO responds as follows.

RESPONSE:

Yes. The Midwest ISO contacted LG&E through its counsel on and after October 30, 2003, seeking a wide variety of information related to the LG&E/KU system that has been reflected in the benefit-cost study. See generally, prior Midwest ISO discovery requests.

Witness: Ronald McNamara

REQUEST:

56. What is the estimate of the MISO Schedule 10 rates if the 15 cents per MWh cap were not imposed? In other words, if there were no cap on the Schedule 10 rate and the MISO were to recover the costs it has allocated to Schedule 10 in the same way as it is currently allocating and recovering costs to Schedules 16 and 17 (from an accounting and cost recovery perspective), what would the rate be?

RESPONSE:

For purposes of this response, it is assumed that the cap remained in place through December 31, 2004, and then was eliminated. The estimated Schedule 10 rate per MWh for the period 2005 through 2010 under this assumption is as follows:

Schedule 10 ($/MWh)			
Year	Demand	Energy	Total
2005	0.117	0.038	0.155
2006	0.115	0.037	0.152
2007	0.114	0.037	0.151
2008	0.111	0.036	0.146
2009	0.100	0.032	0.132
2010	0.097	0.031	0.128

Note -- the demand rate above is applied to the demand-based billing determinants and the energy rate above is applied to the energy-based billing determinants.

Witness: Michael P. Holstein

REQUEST:

57. In the market simulation conducted by MISO with Promod IV, specifically state whether the bilateral market or the existence of forward contracts was included in the model. If not please state whether the simulation results would be any different if you had considered the bilateral market or the existence of forward contracts and explain any such differences.

RESPONSE:

The Midwest ISO's PROMOD IV modeling analysis specifically reflected the existence of a bilateral power market. In cases in which LG&E/KU was not operating under the Midwest ISO Energy Markets Tariff, all LG&E/KU off-system power purchases and sales were modeled as occurring in and subject to the limitations of a bilateral market. In cases in which LG&E/KU operated under the Midwest ISO Energy Markets Tariff, off-system power purchases and sales were modeled based on reasonable utility management's adjusting any bilateral transactions to take advantage of the opportunities for cost reduction and increased sales created by allowing regional economic unit commitment and dispatch to modify the operation of the companies' marginal units. With respect to forward transmission service contracts, the effects of LG&E/KU grandfathered transmission agreements were specifically modeled in the GFA Carve Out Sensitivity Analysis. See Table 8 attached to Dr. McNamara's rebuttal testimony.

Witness: Ronald McNamara

REQUEST:

58. In the market simulation conducted by MISO with Promod IV, specifically state whether self-commitment or self-scheduling was included in the model. If so, please list the units that were assumed to be self-committed or self-scheduled and explain the criteria for making these assumptions. If not, how would the inclusion of self-commitment or self-scheduling of units change the simulation results?

RESPONSE:

In modeling runs in which LG&E/KU were not operating under the Midwest ISO Energy Markets Tariff, all LG&E/KU generation was modeled as being committed and scheduled by LG&E/KU. In cases in which LG&E/KU operated under the Midwest ISO Energy Markets Tariff, the commitment and scheduling of LG&E/KU generation was modeled based on reasonable utility management of the commitment and scheduling of generation to take advantage of the opportunities for cost reduction and increased sales created by allowing regional economic unit commitment and dispatch to modify the operation of the LG&E/KU marginal generating units.

Witness: Ronald McNamara

REQUEST:

59. In reference to Exhibit RRM, Table 4, "Off System Sales Comparison", in the row labeled "Ave. Hourly LGE Gen Price ($/MWh)" for the column labeled "MISO Day 1 Operations" shows a value of $17.67 and for the next column labeled "Day 2 LGE in MISO" shows a value of $18.94.

a. Please provide a detailed explanation of the table headers/labels.

b. Is the value of $17.67 ($/MWh) for the "MISO Day 1 Operations" an estimate of the average price that LG&E/KU receives for its off-system sales in the current Day 1 market?

c. Is the figure of 10,283,998 MWh in the row labeled "LGE Off-System Sales MWH" an estimate of the LG&E/KU off-system sales in the current Day 1 market?

d. Please provide a table summarizing the average monthly day-ahead and real-time market clearing prices in PJM, NY ISO and ISO NE over the past 3 years or provide Web addresses to the sites or documents at these three RTOs where such information can be found.

RESPONSE:

a. Each of the column headings refers to a forecast of anticipated outcomes for 2005 under a specific scenario. The scenarios modeled were as follows:

Column Heading	Description
MISO Day 1 Operations	Reflects continuation of the current approach to transmission operations assuming the Midwest ISO continues Day 1 type operation of the transmission system, LG&E/KU remain in the Midwest ISO, and conservative hurdle rates.
Day 2 LGE in MISO	Reflects anticipated results given that LG&E/KU remain in the Midwest ISO and the Energy Markets Tariff is implemented.

Witness: Ronald McNamara

Day 2 LGE Out of MISO with Conservative Hurdle Rates	Refers to the TORC option (or other alternatives in which LG&E/KU are not fully integrated into a regional LMP market) and reflects conservative hurdle rates that overstate the off-system sales LG&E/KU can be expected to enjoy under the TORC option.
Day 2 LGE Out of MISO with Model Benchmarked to Historical Sales Levels	Refers to the TORC option (or other alternatives in which LG&E/KU are not fully integrated into a regional LMP market) and uses hurdle rates that were required to limit modeled LG&E/KU off-system sales for 2003 to more closely match historical sales levels.

The row labels refer to LG&E/KU forecasted off-system sales volumes, generation hub prices, or off-system sales revenues for 2005 in the above listed scenarios. The three price points provided refer to:

- *Ave. Hourly LGE Gen Price:* A simple average of hourly generation prices with equal weight given to each hour;
- *Volume Weighted Ave. LGE Gen Price:* An average generation price weighted by LG&E/KU generation in each hour; and
- *Vol. Weighted Ave. LGE Off-System Sale Price*: An average generation price weighted by LG&E/KU off-system sales in each hour.

b. The $17.67 ($/MWh) is a forecast value of LG&E/KU generation at the location of LG&E/KU generating facilities. See the Midwest ISO's response to Request No. 59(a) for a description of the scenario.

c. The 10,283,998 MWh is a forecast value of LG&E/KU off-system sales for the identified scenario. See the Midwest ISO's response to Request No. 59(a) for a description of the scenario.

Witness: Ronald McNamara

d. The website addresses of the above-referenced RTOs are: www.pjm.com; www.nyiso.com; and www.iso-ne.com.

Witness: Ronald McNamara

REQUEST:

60. With regard to MISO's cost-benefit analysis, does it include any costs that MISO is currently deferring related to market start up or market design? If so, please identify those costs. If not, please provide a detailed accounting of all such costs that MISO is incurring or has incurred related to Day 2 markets that it is not currently recovering. If possible, please provide this data by FERC account if available by FERC account.

RESPONSE:

Yes, the Midwest ISO is deferring its market start-up and market design costs. The attached schedule reflects the Midwest ISO's projected deferred regulatory assets by category, including the market deferral, through December 31, 2004, as set out under FTR Pre-Operating Costs and Energy Market Pre-Operating Costs. The schedule also reflects the 2005 Annual Amortization Expenses that are expected to be recovered in 2005.

Witness: Michael P. Holstein

Deferred Regulatory Assets	Projected Balance December 31, 2004
Sch 10 Pre-Operating Costs	30,720,000
FTR Pre-Operating Costs	19,714,000
Energy Market Pre-Operating Costs	61,069,000
Grid America Deferred Payment	27,814,000
Illinois Power Payment	8,966,000
Settlement	25,000,000
Sch 10 Deferred due to rate cap	3,014,000
Balance	176,297,000

Annual Amortization 2005 Expense	YTD December 31, 2005	
Sch 10 Pre-Operating Costs	9,819,000	7 year amortization - ends 2008
FTR Pre-Operating Costs	2,701,000	7 year amortization - ends 2012
Energy Market Pre-Operating Costs	8,208,000	7 year amortization - ends 2012
Grid America Deferred Payment	3,125,000	10 year amortization - ends 2013
Illinois Power Payment	912,000	10 year amortization - ends 2014
2005 Expense	24,765,000	

REQUEST:

61. In the Promod IV model simulations conducted for the MISO's cost-benefit study, how are the loads distributed across all the nodes in the model? Does this distribution of loads change during the 8760 hour simulation?

RESPONSE:

The hourly area loads are distributed over the nodes for that area in proportion to the load at each bus in the powerflow data. Powerflow load at a bus is considered to be the sum of the real load at the bus and the shunt capacity at the bus. The proportionality factors for allocating the load to the nodes do not change from hour to hour.

Witness: Ronald McNamara

REQUEST:

62. Is Dr. McNamara contend that joining a centrally administered market with (arguendo) net benefits for the entire market, that there are also net efficiency gains for each and every joining party? Is Dr. McNamara's position that there cannot under any circumstances be cost shifting such that there may be a net loss for some at the gain of others? Please provide the net savings for each and every MISO member that result from the EMT, consistent with that provided for LG&E/KU.

OBJECTION:

The request is overly broad in that it requests information not relevant to this proceeding and unduly burdensome to the extent it would require the Midwest ISO to undertake benefit-cost studies for each other Midwest ISO member. Without waiving this objection, the Midwest ISO responds as follows.

RESPONSE:

Dr. McNamara's position is that implementation of the Midwest ISO EMT will provide significant benefits to Midwest ISO members and that those benefits are broadly distributed among member organizations. In those cases in which the Midwest ISO has conducted analyses of benefits and costs to specific member companies (LG&E/KU and Wisconsin utilities), participation in the Midwest ISO EMT has been shown to provide significant net benefits to member companies. A copy of "The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets: Initial Results (March 26, 2004)" is attached.

Witness: Ronald McNamara

Miso

The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets

Initial Results

March 26, 2004

Prepared with the Support of:
Science Applications International Corporation
New Energy Associates

Table of Contents

Executive Summary

In December 2004, the Midwest Independent System Operator (MISO) will begin providing security-constrained, economic dispatch services and operating a Real-Time Market for wholesale energy. MISO also will create a Day-Ahead Market and Financial Transmission Rights (FTRs) to permit participants to hedge market risks.

Based on initial results after taking into account market related costs, participation of Wisconsin MISO member utilities in the MISO Energy Markets can be expected to produce near-term savings of $51 million per year. The projected savings are primarily the result of approximately $60 million per year in reduced generation and purchased power costs paid by Wisconsin utilities and more efficient use of the existing transmission system.

MISO has undertaken this study to address questions regarding the economic impacts of Wisconsin utility participation in the market. Some stakeholders in Wisconsin had expressed concern that, given current levels of transmission congestion and the state's reliance on power imports, participation in a regional energy market might increase costs. To avoid these impacts, it had been suggested that Wisconsin utilities defer their participation and operate under current rules during the completion of planned transmission improvements. However, the initial results of the study indicate that market participation in 2005 is likely to produce net benefits for Wisconsin.

Detailed production costing and power flow modeling has been undertaken to evaluate proposed FTR allocations and the overall impact of market participation on Wisconsin consumers.

This report presents results from the initial model runs completed in the analysis. A subsequent report will include results from additional model runs covering alternative scenarios and sensitivity analysis.

MISO's energy market tariff will change current operations in three major areas:

- Real-time, regional, security-constrained, economic dispatch will replace the current system for managing the congestion that occurs when the transmission system cannot accommodate all transmission service requests. Currently congestion is managed through reservations of estimated Available Flowgate Capacity (AFC) and the North American Electric Reliability Council's (NERC's) Transmission Loading Relief (TLR) procedures.

- Real-Time and Day-Ahead energy markets will provide a transparent and liquid wholesale spot market that reveals the value of power at each commercially significant location in the transmission system. The development of a transparent regional spot market will expand trading opportunities and help utilities optimize power purchases and sales.

- Financial Transmission Rights will replace the current system of "physical rights." "Physical rights" are classifications and priorities that determine the order in which transmission service will be curtailed when the system cannot accommodate all requests. In the current system, no compensation is paid when transmission service is curtailed. A FTR compensates its holder for any difference between the price of power for a designated load zone and at a specified source, placing the holder in a financial position comparable to having completed a power transfer from the designated source to that load location. MISO will allocate FTRs to cover a high percentage of current transmission service reservations. An allocation of FTRs equal to less than 100% of current transmission reservations or which fails to compensate for all congestion costs does not necessarily increase costs to consumers. Under the current system when transmission is fully utilized "physical rights" are curtailed and consumers pay the resulting congestion costs.

The proposed changes occur in the wholesale energy market. Wisconsin is a cost-of-service jurisdiction. Retail rates will continue to be regulated on a cost basis by the Wisconsin Public Service Commission. Wisconsin utilities will continue to use their lowest cost resources to serve their Wisconsin retail customers.

The results being released in this report quantify the impacts in 2005 for Wisconsin utilities for the following cases:

- Case 1: Wisconsin MISO members (Madison Gas & Electric, Northern States Power, WE-Energies, Wisconsin Public Power, Wisconsin Public Service, and Wisconsin Power & Light) participate with other MISO companies in the Midwest Energy Market (and Dairyland Power Cooperative which is not a MISO member does not participate) with the March 16, 2004 partial allocation of FTRs; and

- Case 2: Continuation of Current Operations throughout the MISO footprint without the Midwest Energy Market.

For each scenario, we have calculated the cost to serve the native load customers of Wisconsin utilities.

This analysis compares the costs of Wisconsin utility participation in MISO energy markets to a subset of near-term benefits. The Wisconsin share of costs of developing and operating the FTR system and the Real-Time and Day-Ahead energy markets, as reflected in MISO Schedule 16 and 17 charges, have been taken into account in this analysis.

These initial results are based on the outcome of MISO's March 16, 2004 partial Tier 1 and Tier 2 (of four tiers) allocation of FTRs, representing approximately half of the FTRs Wisconsin utilities would be eligible to request. The March 16th allocation is a partial summer peak period allocation. MISO will allow market participants to nominate different sets of FTRs for peak and off-peak periods in summer, fall, winter and spring seasons. To provide a conservative representation of the value of FTRs, we did not consider additional FTRs Wisconsin utilities could receive in the Tier 3 and 4 allocations and assumed that the companies would be required to take their full allocation in each season and period. Allowing companies to nominate for each season and period only those FTRs that were cost-effective for that season and period could have increased the net savings from market participation.[1]

In these cases, we have considered near-term benefits that arise from two sources: reduced reliance on imprecise and inefficient Transmission Loading Relief procedures for congestion management and economic efficiency gains from moving to centralized dispatch.

In this analysis, no attempt has been made to quantify other longer-term benefits that could be realized from the introduction of transparent, liquid wholesale markets for electricity in Wisconsin. If Wisconsin is inside the MISO energy market, Wisconsin utilities and the Wisconsin Public Service Commission would be able to:

- Use location-specific prices to help identify where it may be most cost-effective to build new generation and transmission capacity;

[1] Under current proposals, market participants will be able to nominate, for each season and for peak or off-peak periods, FTRs that are expected to pass a break-even test for that season and period. Filtering the March allocations on that basis, would increase the net savings in this analysis to Wisconsin for market participation from $51 million to $64.7 million per year.

- Take advantage of a larger and more liquid market should it decide to shift from ratepayers to investors some or all of the capital investment risks associated with the development of new capacity;

- Benchmark utility fuel and operating costs against location-specific spot prices;

- Use price signals to improve management of maintenance and outage scheduling;

- Design variable pricing products based on efficient price signals that price responsive consumers can trust to reflect the actual real-time or day-ahead cost of power; and

- Foster the development of differentiated consumer energy products designed to better match consumer risk preferences.

At the request of Wisconsin stakeholders, benefits and costs are presented for the state as a whole and not for individual utilities. Based on the request of Wisconsin stakeholders, the results include the cost to serve customers of Wisconsin utilities located in the Upper Peninsula of Michigan and exclude costs to serve the non-Wisconsin service territories of Alliant, Dairyland Power Cooperative (DPC), and Northern States Power (NSP). Jurisdictional separation factors developed in consultation with the respective companies will be applied to DPC and NSP costs. Separate pools were modeled for Alliant's Wisconsin and non-Wisconsin operating companies.

The results for our initial cases are presented below in Table 1. They show that total generation and purchased power costs will decline by $60.4 million per year if Wisconsin utilities participate in the Midwest Energy Market. This amount more than offsets the expected $12.9 million per year that Wisconsin utilities would pay in MISO Schedule 16 and 17 costs and the approximately $41.4 million in congestion costs incorporated in the market price of Wisconsin generation purchased by Wisconsin companies. The extent of the net benefits from participation in the market depends in part on the allocation of FTRs to Wisconsin utilities. If Wisconsin utilities were to receive only their March 2004 Tier 1 and Tier 2 allocations, net savings to Wisconsin from market participation are expected to be $51.2 million per year. The March 16th partial allocation has an estimated annual value to Wisconsin utilities of $ 44.9 million per year.

Table 1: Net Savings and Breakdown of Savings in Cost to Serve Load from Wisconsin Participating in Midwest Energy Market[2]

Net Savings to Wisconsin from Participating in the Energy Market	
Case 1: Wisconsin MISO Members in Energy Market	$1,630,080,002
Case 2: MISO Current Operations	$1,681,258,328
Net Savings from Market Participation	**$51,178,325**
Breakdown of Net Savings by Category	
Reduced Generation & Purchased Power Costs	$60,433,958
Increased Revenues from Off-System Sales Outside WI	$187,259
Less: Schedule 16 & 17 Costs	($12,984,606)
Less: Net Wisconsin Congestion Costs	($41,405,082)
FTR Revenues	$44,946,864
Total Net Benefit	**$51,178,393**

[2] Cost to Serve Load, as report, includes only incremental generation and transmission costs.

1. Introduction

To quantify the economic benefits and costs of Wisconsin utilities participating in MISO energy markets, this initial release of results focuses on a sub-set of near-term economic benefits of Wisconsin participating in the Midwest Energy Market. These initial results address two scenarios: participation of Wisconsin MISO member utilities in the Midwest Energy Market and a continuation of current operations without a coordinated energy market. The economic impact of different scenarios is being analyzed using PROMOD IV™, a chronological production costing and detailed power flow model of MISO and adjacent regions. The near-term economic impacts that are quantified in these initial results include:

- More efficient real-time congestion management under MISO economic dispatch than is possible using TLR procedures;

- Opportunities for Wisconsin utilities to improve off-system purchases and sales if they participate in the MISO market;

- Payment of congestion costs associated with the implementation of Locational Marginal Pricing (LMP);

- The receipt of revenues through alternative allocations of Financial Transmission Rights; and

- Schedule 16 and 17 charges for MISO administration of FTRs and energy markets.

Each scenario was modeled for the 2005 calendar year.

The near-term benefits and costs addressed in these initial results are only part of the picture. This analysis does not incorporate costs of current reliance on conservative and inherently imprecise estimates of Available Flowgate Capacity to reserve and schedule transmission service. Additionally, participation in the market will immediately provide MISO reliability coordinators greater real-time control over power flows improving system reliability. Moreover, the development of transparent and efficient spot markets will change economic incentives and produce significant intermediate and long-term efficiency benefits.

The remainder of this report is divided into three sections addressing: effects of market participation, cases, and results. Appendix A to this report describes the modeling methodology and responds to specific Wisconsin stakeholder questions.

2. Effects of Market Participation: Near-term Congestion Management and Power Purchase and Sale Benefits

The transmission system in Wisconsin and most of the United States cannot accommodate all requests for transmission service. Although there are cost-effective improvements that should be made, it would be uneconomic to build transmission capacity to accommodate all requests. In many instances, managing congestion by efficiently re-dispatching resources should be more cost-effective than building new transmission capacity.

Currently MISO, in its role as reliability authority, does not coordinate the dispatch of generation. The existing approach used to avoid and manage congestion in the transmission system relies on estimating Available Flowgate Capacity (AFC) for purposes of reserving and scheduling available capacity and curtailments of transmission service under Transmission Loading Relief (TLR) procedures – physically rationing transmission capacity based on priorities related to firmness and length of service. Like all physical rationing mechanisms, this is a mechanism that contains inherent inefficiencies, distorts market outcomes, and reduces consumer benefits when compared to a market based system.

More specifically, the current system of physical rights and TLRs is inefficient as a result of:

1. Imprecise TLR procedures that result in underutilization of transmission capacity when the demand for transmission capacity is high;

2. Inherently conservative and imprecise estimates of AFC often prevent market participants from reserving and scheduling the full capacity of the transmission system;

3. The lack of a transparent spot market which increases transaction costs (including: search, contracting, scheduling, settlement, managing counter-party risk, and dispute resolution costs) and imposes opportunity costs from parties over committing their own generation and being unable to identify and complete through sequential bilateral transactions the most economic set of short-term purchases and sales;

4. To ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions and avoid more frequent schedule curtailments, in a physical rights system operators do not schedule against a portion of transfer capacity, known as a Transmission Reliability Margin (TRM);

5. Uneconomic curtailments under TLR procedures that do not take into consideration at that time the value of the transactions being curtailed; and

6. The inability of reliability coordinators to redispatch generation in real-time which limits the precision and speed of responses to events and could compromise system reliability.

The initial results presented in this report address only the first (TLR) and third (Transaction and Opportunity Cost) impacts.

A. TLRs and Capacity Underutilization

Reliance on TLRs for congestion management inherently leaves transmission capacity under utilized because TLRs rely on imprecise estimates and cannot accurately reflect system interactions.

Under NERC TLR procedures, the impact of control area to control area transactions and local generation on constrained facilities is estimated using power flow distribution factors. The estimated distribution factors reflect reported control area to control area interchange schedules and reported transmission facility outages. However, power flows estimated using NERC procedures and data do not consistently correspond to actual power flows.

Moreover, TLRs are issued to curtail specific transmission transactions. When a transaction is curtailed the control areas affected redispatch generation, curtail load, or reconfigure their systems to comply. Each of these actions takes time and occurs within constantly changing patterns of load, generation, and power flows. Because each change in dispatch, load levels, or system configuration will have power flow impacts and the parties' responses to the curtailment are not coordinated, the simultaneous impact on the constrained flowgate of the responses to a TLR cannot be precisely predicted.

As a result, it is not possible for reliability coordinators to use TLRs to maintain power flows at post-contingency limits on a sustained basis. Consistent with the responsibility of reliability coordinators to avoid operating security limit violations, some amount of transfer capability goes unutilized during TLR events.

We have analyzed MISO's experience during 198 TLR level 3 – 5 events for Alliant, Dairyland Power Cooperative, Madison Gas & Electric, Northern States Power, Wisconsin Electric, Wisconsin Public Power, and Wisconsin Public Service flowgates from June through November 2003. These events comprise the TLRs for which MISO had recorded power flows over the constrained flowgate during the sample period. We determined the amount of unused capacity on these flowgates during TLRs based on the actual and post-contingency power flows recorded at 30 second intervals in MISO's flowgate monitoring tool. This unused capacity was then averaged over the total time period during the TLR for which data was available. We found that on average 11.407% of the (post-contingency) flowgate capacity was unused during these TLR events. When modeling TLR based congestion management, flowgate capacities on the transmission systems of the Wisconsin utilities included in our TLR analysis were reduced by 11.407% to reflect the average amount of capacity that is unused during TLR events.

We have completed a comparable analysis for a sample of 28 TLR events from a less constrained area outside of Wisconsin. The results for this smaller sample, in which 7.78% of capacity was unused during TLR events, was applied to model TLR based congestion management on non-Wisconsin MISO and MAPP flowgates, providing a conservative representation of the impact TLR congestion management on capacity utilization.

The flowgate capacities applied in the two cases in this initial release have been reduced for TLR impacts in accordance with the following classifications specified in Table 2 below. AFC impacts are not included in the initial results being reported today.

Table 2: Effective Physical Limits on Flowgate Capacity

Category / Case*	**Case 1: Wisconsin MISO Members in Midwest Energy Market**	**Case 2: Current Operations**
Category 1: Involves PJM OR Outside MISO	0%	0%
Category 2: MISO outside NSP, DPC & ATC OR MISO at the boundary with any Non-MISO pool except PJM	0%	7.78%
Category 3: MISO at the boundary with DPC, NSP or ATC; OR within NSP, OR NSP at the boundary with ATC, DPC, or a Non-MISO pool	0%	11.407%
Category 4: ATC; OR ATC at the boundary with DPC; OR ATC at the boundary with Non-MISO other than PJM	0%	11.407%
Category 5: DPC OR DPC at the boundary with Non-MISO pool	11.407%	11.407%
Category 6: Within or between other Non-MISO MAPP areas	7.78%	7.78%

* For purposes of this analysis LES and MHEB are treated as outside MISO because they will be outside the MISO Energy Market in 2005.

B. *Transaction and Opportunity Costs*

In the absence of coordinated regional dispatch and the transparent real-time market that such dispatch will create, individual utilities must engage in a sequence of bilateral transactions in an attempt to improve the economic utilization of their facilities.

Reliance on bilateral trading involves inherent inefficiencies:

- Current practices reflect an appropriately conservative bias given the lack of a liquid spot market towards commitment of the utility's own generation to serve its native load.

- Existing scheduling procedures limit market participants to whole hour or longer transactions. By contrast, MISO energy markets will be able to optimize the operation of generation across member utilities on at least a five-minute basis.

- Finding a cost-effective mix of purchases and sales requires bilateral negotiations with multiple other market participants. Such negotiations and the resulting transactions impose transaction costs related to the search for cost-effective transactions, contracting, scheduling, settlement, managing counter-party risk, and dispute resolution. These transaction costs are a direct cost to market participants.

- In such negotiations, each participant has an incentive to limit its disclosure to counter parties to capture as large a portion of the benefits from the transactions as possible. Given imperfect information and a non-transparent market, identifying a cost-effective mix of transactions takes time and not all economic transactions will be discovered.

- Given a lack of transparency, price spreads will occur that do not reflect genuine differences in marginal costs. These spreads create misleading operating incentives that may fail to mitigate and in some cases exacerbate transmission congestion.

- Power markets are highly dynamic. Given the transaction costs and the time involved in completing bilateral transactions, the utilities' generation, purchases and sales are rarely optimized. This failure to optimize the operation of generation across entities imposes an opportunity cost on each utility and can significantly increase total generation costs.

Regional security-constrained economic dispatch under the proposed MISO tariff will optimize resource utilization without market participants having to engage in serial short-term bilateral transactions. A liquid LMP market assures a load serving entity (or supplier) located inside that market that it can consistently purchase (or sell) real-time or day-ahead energy at the best competitive price bid (or offered) with respect to the location of its load (or generation). This is not true for the load serving entity (or generator) outside the boundary of the LMP market. For such a buyer (or seller), purchasing (or selling) at the boundary of the LMP market is only one of numerous alternatives for which it must forecast results and that it must evaluate in comparison to other potential bilateral deals. Thus, the load serving entity (or supplier) outside the boundaries of the LMP market still faces transaction costs and substantial opportunity costs associated with maintaining a sub-optimal mix of generation, purchases, and sales.

To take into account these market inefficiencies and prevent the model from relentlessly over optimizing transactions in comparison to actual bilateral market experience, hurdle rates were applied to transactions between dispatch pools. These hurdle rates may include two components:

- The incremental transmission charge associated with purchasing power from another area to serve load within the dispatch pool; and

- A transaction and opportunity cost component to reflect the inherent inefficiencies of relying on a bilateral market.

The incremental tariff charge for transactions within MISO was set to zero to reflect the ability of Load Serving Entities to use network integration service. Similarly, the tariff component was set to zero for transactions between MISO and PJM, reflecting an elimination of through and out rates between the two RTOs. Applicable hourly non-firm point-to-point transmission charges were applied to transfers between other entities.

The transaction and opportunity cost portion of the hurdle rate was generally set at $3/MWH for transactions between pools that were not in (the same) energy market.[3] It was applied in the dispatch of generation. A separate hurdle rate was not applied to unit commitment, although the model does commit generation, in part, based on anticipated sales given the dispatch hurdle rate.

Setting the hurdle rate at the applicable tariff charge plus $3 for transaction and opportunity cost inefficiencies provides a conservative estimate of the inherent barriers to transactions in a bilateral market. Comparable studies have used higher hurdle rates to reflect such inefficiencies, see: Table 3.

Table 3: Comparison of Hurdle Rates Applied to Transactions Not Within an RTO Market

Study	**Unit Commitment Hurdle Rate**	**Dispatch Hurdle Rate**
U. S. Dept. of Energy, *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (April 30, 2003)	Between Control Areas: $10/MWH	Between Control Areas: $5/MWH + Tariff Charge
CRA, *The Benefits and Costs of Dominion Virginia Power Joining PJM,* (June 25, 2003)	Between Control Areas: $10/MWH	$7/MWH for single control area to control area sale + $4/MWH for each additional control area to control area transfer
CRA, *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast* (November 6, 2002)	Between Control Areas: $10/MWH	$5/MWH + Tariff Charge
MISO, *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets* (March 2004)	**None**	**$3/MWH + Tariff Charge**

3. Cases Modeled for Initial Phase 1 Results

For this initial analysis, we are focusing on a subset of near-term benefits and costs. For each scenario, we calculated the cost to serve the retail customers of Wisconsin utilities. Following the input of Wisconsin stakeholders, costs were calculated for the state as a whole and are not being reported for individual utilities. Based on stakeholder input, Wisconsin costs include the cost to

[3] To recognize the impact of ATC redispatch procedures that affect some but not all TLR events, the hurdle rate within ATC was reduced to $2.50 / MWH in Case 2.

serve We-Energies and Wisconsin Public Service customers located in the Upper Peninsula of Michigan. And, the cost to serve the non-Wisconsin service territories of Alliant, Northern States Power, and Dairyland Power Cooperative have been excluded from the Wisconsin total based on modeling Alliant West as a separate pool and jurisdictional separation factors provided by Northern States and Dairyland.

This initial release of information covers the two scenarios described below.

A. Wisconsin MISO Members in Midwest Energy Market

In this case, Wisconsin MISO member utilities are assumed to participate in MISO energy markets. MISO MAPP members including Alliant West, Minnesota Power, Ottertail Power, and Montana Dakota Utilities are also modeled as being in the MISO energy market. In this model run, Dairyland Power Cooperative was not included in the market or in MISO.

The calculation of the cost to serve load begins with the total cost of generation (fuel, variable O&M, emission allowance and credit, start-up, and fixed O&M costs) and the cost of power purchased from outside Wisconsin (calculated at load LMPs). The calculation also reflects the operation of the LMP market. This is reflected in a comparison between congestion costs associated with generation purchases from Wisconsin and FTR revenues. Net congestion costs are estimated based on load LMP payments, less the sum of generation LMP revenues paid to Wisconsin generators and the redistribution to Wisconsin utilities of excess loss revenues collected by MISO in the marginal loss component of LMP. In these initial model runs, we used MISO's March 16th Tier 1 and Tier 2 allocation of FTRs. MISO has developed a tiered allocation methodology designed to provide an equitable allocation of FTRs to Wisconsin and other congested areas of the grid. To date, only two of four tiers of this allocation have been released. Finally, Schedule 16 and 17 MISO tariff charges for administration of the FTRs and energy markets are built into the calculation to reflect the cost of Wisconsin utilities participating in the Energy Market.

B. Continuation of Current Operations without Midwest Energy Market

This case reflects MISO operations continuing as they do today. No change in MISO membership and no market development were assumed.

Operating outside the market, the cost to serve Wisconsin load is calculated as total generation costs, plus the cost of power purchases from outside Wisconsin (including power purchased by other Wisconsin utilities from NSP and DPC and attributable to NSP's and DPC's non-Wisconsin jurisdictions), less revenues from off-system sales outside Wisconsin.

4. Initial Results

The cost to serve load has been calculated based on the elements presented in Table 4 below.

Table 4: Calculation of Cost to Serve Wisconsin Load

Utilities in the MISO Energy Market *Applies to:* • MISO Member Companies in Case 1	**Utilities Not in MISO Energy Market** *Applies to:* • Dairyland Power Cooperative in Case 1 • All Companies in Case 2
Generation and Purchased Power Costs, including • Total Generation Costs (Fuel, Variable O&M, Emission Allowance & Credit, Start-up, and Fixed O&M Costs) • Purchased Power Costs (Power purchased outside Wisconsin)	Generation and Purchased Power Costs, including • Total Generation Costs (Fuel, Variable O&M, Emission Allowance & Credit, Start-up, and Fixed O&M Costs) • Purchased Power Costs (Power purchased outside Wisconsin)
Less: Revenue from Off-System Sales Outside Wisconsin	Less: Revenue from Off-System Sales Outside Wisconsin
Schedule 16 & 17 Charges for MISO Development and Administration of FTRs and Energy Markets	Not Applicable
Net Congestion Costs (in addition to congestion costs already included in the cost of power purchased outside Wisconsin) calculated as: • Load Payments at Load LMPs for Generation Purchased in Wisconsin • Less: Generation Revenues at Generator LMPs for Generation sold in Wisconsin • Less: Distribution to Wisconsin Utilities of Excess Loss Revenues collected by MISO in the Loss Component of LMPs	Not Applicable
Less: FTR Revenue based on March 16, 2004 partial FTR allocations	Not Applicable

The results or our initial runs are summarized in Table 5. After taking into account market related costs, participation of Wisconsin MISO member utilities in the MISO Energy Markets can be expected to produce near-term savings of $51.2 million per year. The projected savings are primarily the result of approximately $60 million per year in reduced generation and purchased power costs paid by Wisconsin utilities resulting from more efficient use of the existing transmission system and regional dispatch. The reduction in generation and purchased power costs more than offsets the expected $12.9 million per year that Wisconsin utilities would pay in MISO Schedule 16 and 17 costs and the approximately $41.4 million in congestion costs incorporated in the market price of Wisconsin generation purchased by Wisconsin utilities. The extent of Wisconsin's net benefits from participation in the market depends in part on the allocation of FTRs to Wisconsin utilities. If Wisconsin utilities were to receive only their March 2004 Tier 1 and Tier 2 allocations – approximately half of the allocation which Wisconsin utilities would be entitled to request – the net savings from market participation are expected to be $51.2 million per year. The March 16th partial allocation has an estimated annual value to Wisconsin utilities of $ 44.9 million per year. The March 16th allocation is a summer peak allocation. Off-peak allocations and allocations for other seasons have not yet been released. Our valuation is based on Wisconsin utilities taking their full summer peak Tier 1 and Tier 2 allocations in each season (summer, fall, winter, and spring) and period (peak and off-peak), including seasons and periods in which some individual FTRs may not be cost effective. If Wisconsin utilities nominated in each season and period only those FTRs that were cost effective, based on the partial March 2004 allocation, their net savings from market participation could be as much as $64.7 million annually.

Table 5: Results of –
Case 1: Wisconsin MISO Members in Midwest Energy Market and
Case 2: MISO Current Operations – No Energy Market

Case 1: Wisconsin MISO Members Participating in MISO Energy Market with March Tier 1 & Tier 2 FTR Allocations

Month	Total Generation Costs	Cost of Power Purchased Outside Wisconsin	Wisconsin Congestion Costs	Schedule 16 & 17 Costs	Less: Revenue from Power Sales Outside Wisconsin	Less: FTR Revenue	Cost to Serve Load
1	127,337,619	11,296,282	3,733,752	0	2,868,165	7,120,060	**132,379,427**
2	115,661,605	10,833,388	3,306,565	0	1,504,712	4,545,265	**123,751,580**
3	117,872,372	10,314,080	2,318,864	0	1,712,891	2,006,261	**126,786,164**
4	114,083,775	7,297,430	2,286,894	0	2,758,609	1,831,649	**119,077,841**
5	116,954,820	5,725,063	7,918,751	0	5,855,822	3,990,719	**120,752,093**
6	126,706,017	8,550,871	7,870,947	0	6,333,001	2,183,500	**134,611,334**
7	147,045,963	13,855,077	6,845,555	0	7,500,336	3,832,097	**156,414,162**
8	147,677,805	18,294,473	1,940,676	0	7,553,641	2,404,676	**157,954,636**
9	125,883,837	10,563,447	3,505,302	0	6,468,430	1,455,458	**132,028,700**
10	124,972,249	22,748,298	42,422	0	3,298,121	3,615,167	**140,849,680**
11	124,023,137	25,307,755	728,741	0	1,429,676	7,401,708	**141,228,249**
12	124,069,276	13,089,409	906,613	0	2,243,532	4,560,236	**131,261,530**
	$1,512,288,473	**$157,875,573**	**$41,405,082**	**$12,984,606**	**$49,526,934**	**$44,946,796**	**$1,630,080,002**

Case 2: MISO Current Operations - No Energy Market

Month	Total Generation Costs	Cost of Power Purchased Outside Wisconsin	Less: Revenue from Power Sales Outside Wisconsin	Cost to Serve Load
1	133,106,114	12,779,314	6,306,994	**139,578,434**
2	119,514,430	11,312,974	2,502,062	**128,325,343**
3	120,712,791	10,701,087	2,182,845	**129,231,034**
4	117,204,011	7,105,274	3,904,841	**120,404,445**
5	119,641,709	7,696,523	3,644,014	**123,694,218**
6	129,641,831	12,597,607	4,451,245	**137,788,193**
7	150,054,925	17,140,889	6,449,040	**160,746,774**
8	150,240,528	21,426,433	6,347,406	**165,319,554**
9	127,394,878	11,849,349	4,812,952	**134,431,275**
10	129,120,611	21,890,956	3,185,863	**147,825,703**
11	130,603,310	25,675,458	1,596,105	**154,682,663**
12	129,188,710	13,998,289	3,956,308	**139,230,691**
	$1,556,423,849	**$174,174,154**	**$49,339,676**	**$1,681,258,328**
Net Savings from Market Participation (Case 2 – Case 1)				**$51,178,393**

Appendix A: Production Cost and Power Flow Modeling Methodology

The analysis of benefits and costs of participation in MISO energy markets is based on a simulation of electric system operations and regional power markets using the PROMOD IV® production costing and power flow model. The model was used to project hourly production costs and location-specific market clearing prices.

PROMOD IV® integrates chronological production costing and detailed power flow analysis. The model represents power system operations in the Eastern Interconnect, including representations of the operation of the 5,000 generating units that are 1MW or larger, 40,000 transmission buses, and 50,000 transmission lines. The model calculates and can track location-specific, hourly prices for up to 8,000 specific locations.

The model captures the dynamics of the marketplace through its ability to determine the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PROMOD IV® performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, bus-bar and zonal energy market prices, external market transactions, transmission flows, losses, and congestion prices.

A. *Unit Commitment and Dispatch*

The heart of PROMOD IV® is an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a wide variety of operating constraints.

The unit commitment logic is based on a marginal scheduling algorithm that models generator constraints for minimum runtime and minimum downtime and considers the start-up costs and variable operating costs of each generating unit to develop a unit commitment schedule. This process starts with an initial unit commitment order for the week, and then performs an iterative improvement of the unit commitment schedule for each day of the week, considering the location-specific replacement cost of energy at each generator bus and opportunities to make off-system sales. Checking for violations of minimum runtime and minimum downtime constraints on each unit, the logic looks for alternative commitment decisions that improve the economic performance of the system.

Once the unit commitment schedule is developed, security constrained economic dispatch is performed by loading incremental unit segments in bid order, subject to operational constraints. PROMOD IV® dispatches the power system in each hour to minimize total variable production costs. For generating units, these costs include fuel costs (applied to the heat rate profile of the unit), variable O&M costs, and emissions costs based on forecasted SO_2 and (in NO_x trading regions, e.g. IL) NO_x emission allowance prices. Each unit's cost is scaled by a dynamic transmission loss factor that is calculated each hour during the dispatch, reflecting the unit's incremental effect on total system transmission losses. The unit dispatch procedure simulates detailed hourly chronological dispatch subject to ramp rate limits on maximum hour to hour changes and a Monte Carlo simulation of generating unit outages. Economy transfers from one area to another area are considered in dispatch and reflect a hurdle rate incorporating transmission prices and transaction costs for that buyer/seller pair.

A few unit types are assigned specific generation profiles. For example, river-based hydro are represented as the combination of flat run-of-the-river profile up to its minimum loading level, plus a peaking profile for remaining monthly energy. Pumped storage hydro is assumed to operate with 70% overall efficiency and dispatched on an economic bases as peak shaving. An hourly profile for wind generation was developed based on data provided by the Minnesota Department of Environmental Quality on hourly output from Lake Benton I and II, representing more than 210 MW of wind capacity in the Buffalo Ridge region of southwest Minnesota.

B. Data Sources

At the request of Wisconsin stakeholders, this study was done using published data derived from public and commercial sources. Reliance on public and commercial data ensures the transparency of the analysis and the consistency of data inputs.

The primary data sources include data reported by the utilities to the Federal Energy Regulatory Commission or U.S. Energy Information Administration and published by those agencies, information filed by the utilities with U.S. EPA including submissions to meet their Continuous Emissions Monitoring System reporting requirements, the NERC Energy Supply and Demand database and Generating Availability Data System, and New Energy Associates' PowerBase® database. PowerBase® draws data in part from Resource Data International, subject to review and adjustments by New Energy Associates.

The following sections describe the sources and basis for various data inputs. Initially proposed input data was previously shared with Wisconsin stakeholders, and the discussion below identifies the changes made in response to stakeholder comments.

C. Fuel Price Forecasts

The gas and oil fuel price forecasts used in the modeling have been developed using two components. The first component is a general market price forecast based on futures market prices. The second is a basis differential, established based on historic locational price relationships.

i. Natural Gas Price Forecast

The forecasted market price component for natural gas are based on the January 21, 2004 NYMEX forward prices for natural gas at Henry Hub for delivery in each month of 2005.

Locational basis differentials for each state for natural gas were determined by taking the difference between the average delivered price of natural gas in each state over the period January 1999 through December 2002 and the average daily spot price at the Henry Hub for delivery in that same month. The natural gas basis differentials tend to widen in the winter when deliveries on the pipeline system can be capacity constrained. The basis differentials have been set on a monthly basis so as to reflect these seasonal patterns.

The delivered cost data used to calculate basis differentials are the costs reported by utilities for spot and interruptible gas on the Energy Information Administration Form EIA 423. This survey is designed to capture cost data that includes both interstate pipeline and local distribution company transportation charges. These data are aggregated by state and published by EIA in *Electric Power Monthly,* and the underlying data are available in an on-line data base. Beginning in December 2002, the published data no longer distinguish between the cost of spot, interruptible, and contract gas purchases.

In general, state level average natural gas costs were utilized to calculate the natural gas basis differentials. However, EIA did not publish any gas fired generation fuel cost data for South

Dakota or Tennessee, and data from adjacent states (North Dakota for South Dakota) was used to calculate locational basis differentials for these states.

In a small number of instances, EIA gas costs include anomalous data that appear to reflect data entry errors by the submitting company or EIA. Anomalies were investigated by reviewing the disaggregated company Form EIA 423 data. In a few cases, the data entries were judged to very likely reflect some kind of data error, and the state average was recalculated excluding this observation.

ii. #2 Fuel Oil Price Forecast

A similar methodology is used to develop forecasted prices for the #2 fuel oil. The price forecast component for #2 oil price is the January 21, 2004 NYMEX futures price for #2 oil delivered in New York harbor during each month of January – July 2005. Futures contracts for #2 oil are not currently traded on NYMEX past July 2005. To continue the series through December 2005, month-to-month percentage changes #2 oil prices were assumed to equal the month-to-month percentage change in the price of NYMEX futures for light, sweat crude oil. Historically there has been a reasonably consistent relationship between #2 and light, sweat crude prices.

The state-by-state locational basis differentials relative to the New York Harbor futures market price were calculated using the costs reported by utilities for spot purchases of #2 oil on Form EIA 423. As in the case of natural gas, this survey is designed to capture delivered costs including transportation charges. State level average #2 oil prices were utilized to calculate locational basis differentials.

There were gaps in the Form EIA 423 data for South Dakota and in regions outside of MISO. Data from representative states (North Dakota for South Dakota) was used to address these gaps. Additionally, a small number of apparent data reporting entries were identified and excluded from the analysis.

The summer-winter swing in location basis differentials tends to be less for #2 oil than for natural gas, reflecting lower storage costs and the availability of multiple modes of transportation.

iii. Residual Fuel Oil Price Forecast

The residual oil forecast is based on a comparable methodology to that used for natural gas and #2 fuel oil prices. The price forecast component of the residual oil price was based on the January 21, 2004 NYMEX futures price for light, sweat crude during each month of 2005. The futures market price for crude oil is utilized because there is no forward market for residual oil, and residual oil prices are reasonably well linked to crude oil prices. The basis differential for residual oil is calculated in essentially the same manner as for natural gas, using the differential between the delivered residual oil costs reported by utilities on the Form EIA 423 and the spot price of crude oil. Basis differentials are applied to the NYMEX forward price for light, sweat crude delivered to the pipeline at Cushing, OK in order to develop forward projections for residual oil prices that reflect both locational price differences and the price difference between crude and residual oil. There are gaps in Form EIA 423 data for delivered residual oil costs for several states. We utilized the Michigan basis differential for Wisconsin, Minnesota, Iowa, and South Dakota given gaps in the EIA data for those states.

iv. Coal & Uranium Price Forecasts

Coal and uranium price forecasts were taken from Powerbase and derived from facility specific information for the delivered cost of coal and representative regional nuclear fuel costs reported by Resource Data International. Following comments by Wisconsin Public Service, coal and uranium price forecasts were updated to reflect a more recent RDI release.

D. Unit Characteristics

MISO provided generating data from PowerBase® to the Wisconsin companies for their review. The companies were asked to review this data and provide comments, modifications, and additions that would improve the quality of the Benefit - Cost study. The information provided by Wisconsin companies for the different units include:

1. Status and capacity changes
2. Variable and Fixed O&M
3. Start-up costs
4. Heat Rates
5. Operational Constraints
    a. Unit Downtimes
    b. Unit Uptimes
    c. Ramp Rates
6. Maintenance Schedules
7. Operating Reserves
8. Must-Run Status
9. Emission and Control Allowance

Table A-1 below summarizes the results of the review process and the comments received from the Wisconsin utilities regarding the generating unit data. All specific data revisions requested by the utilities were incorporated in the analysis.

Table A-1: Results of Wisconsin Utility Review of Unit Data – Modified Inputs Provided

Company	Status/Capacity Changes	Unit Operator (Orphan Units)	Variable/Fixed O&M	Star-Up Costs	Heat Rates
Alliant Energy	Provided	Provided	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
ATC	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope
DPC & Gensys	Provided	Provided	Provided	Provided	Provided
MG&E	Provided	Did not Provide	Did Not Provide - MG&E finds the delivered information appropriate	Did Not Provide - MG&E finds the delivered information appropriate	Did Not Provide - MG&E finds the delivered information appropriate
We-Energies	Provided	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not provide - We - Energies finds delivered information acceptable	Did not provide - We - Energies finds delivered information acceptable
Wisconsin Public Power	Provided	Provided	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
Wisconsin Public Service	Provided	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Commented on Heat Rate values. Did not make changes to the information sent by MISO
Xcel Energy Services	Did not provide	Did not provide	Did not provide	Did not provide	Did not provide

Table A-1 (Continued)

Company	Operational Constraints: Down/Up-time & Ramp Rates	Maintenance Schedule	Operating Reserves	Must-Run Status	Emission Controls & Allowance	Wind Profile
Alliant Energy	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
ATC	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope
DPC & Gensys	Provided	Provided	Provided	Provided	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
MG&E	Provided	Provided	Provided	Provided	Provided	Did not make changes to the information sent by MISO
We-Energies	Provided	Provided	Provided	Provided	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
Wisconsin Public Power	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
Wisconsin Public Service	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO	Did not make changes to the information sent by MISO
Xcel Energy Services	Did not provide	Did not provide	Did not provide	Did not provide	Did not provide	Did not provide

i. Status and Capacity Changes

PowerBase utilizes RDI's BaseCase and GADS databases as the main source of unit status and capacity changes.

As shown in Table One, all Wisconsin companies except Xcel Energy provided information related to status and capacity changes for their units.

Alliant Energy made comments with respect to the modeling of the Emery Generating Station and the shared capacity for the Riverside Generating station between Alliant East and Madison Gas and Electric. The Emery combined cycle plant was modeled under the name of Power Iowa, and its capacity has been changed to 570 MW based on the information in an owner press release. The commitment and dispatch of the Riverside station are discussed below.

Dairyland Power Cooperative (DPC)/ Gensys provided capacity information for units not included in the original review list such as Bellevue, Cashton, Independence, McGregor, Merrillan 2, and Viola. DPC also provided changes in capacity for other units shown in the review list such as Arcadia, Argyle, Cumberland, Elroy, Fennimore, Forest City, and New Lisbon. All the information was incorporated in the database.

Capacity changes were provided for all units in Madison Gas & Electric except for Blount #1, Rosiere Wind Park, and the University of Wisconsin gas turbine. These capacity changes were added to the database. In addition, a monthly capacity profile was developed for 2005 for the Fitchburg, Nine Springs, and Sycamore combustion turbines according to the summer/winter capacity information provided to MISO for those units.

MG&E also provided information on its participation in the Columbia units with Wisconsin Power and Light (WPL) and Wisconsin Public Service (WPS). All the information was incorporated in the database.

We-Energies provided capacity changes for all units in Concord, Germantown, Oak Creek South, Paris, Pleasant Prairie, Point Beach, Port Washington, and Presque Isle power plants, including the decommissioning of Port Washington #4 and #6. Changes also were provided for Valley #1 and # 2 units. All the information was incorporated in the database.

Wisconsin Public Power submitted comments with respect to changes in the generating capacity and location of some of the units listed in their control area. The 52 MW Kaukauna CT was added as a new unit going commercial in May 2004. Black River Falls CT, Kaukauna Diesels, and Menasha IC units were retired according to the information provided by WPPI. The capacity at the River Falls combustion turbine oil unit was changed to 21 MW. Based on instructions from WPPI, Mosinee Paper and Packaging Corporation of America units were modeled as part of the Wisconsin Public Service control area, and the Stiles Hydro and Scott Worldwide Oconto Falls hydro run-of-river units were modeled as part of the We-Energies control area. The small hydro units such as New Badger, Rapide Croche, and Kaukauna that serve the local load in Kaukauna Utilities were decommitted because WPPI reports its load forecast net of this load and generation.

Finally, Wisconsin Public Service provided comments on generating unit capacity information. The Calpine Fox unit is modeled as Kaukauna Mid America with a capacity of 235 MW based on information from owner press releases. The second Port Washington Combined Cycle unit was scheduled to go commercial starting in 2007 rather than 2005 and Port Washington units #4 and #6 were retired in 2003 based on the information provided by We-Energies and Wisconsin Public Service.

ii. Fixed and Variable O&M

PowerBase utilizes RDI's BaseCase as the main source of fixed and Variable O&M.

Only Dairyland Power Cooperative/Gensys provided updates to the Variable and Fixed O&M information distributed to Wisconsin Companies. Madison Gas and Electric indicated the fixed and variable information is appropriate for their units. All updated information was incorporated in the database.

iii. Start up Costs

The start-up cost information was developed by New Energy Associates and is based on a standard estimation methodology for steam, combined cycle, and combustion turbine unit types.

Only Dairyland Power Cooperative/Gensys provided updates to start-up cost information distributed to Wisconsin Companies. Madison Gas and Electric indicated the start-up cost information is appropriate for their units. We-Energies initially requested a confidential treatment before providing updates to start-up cost data and subsequently determined that the data provided by MISO was acceptable. All updated information was incorporated in the database.

iv. Heat Rates

PowerBase utilizes RDI's BaseCase as the main source of unit Heat Rate information.

Only Dairyland Power Cooperative/Gensys provided updates to heat rate information distributed to Wisconsin Companies. Third order polynomial input/output curves were created using average heat rates at different capacity states provided by DPC for the Alma #4 and #5, Genoa, JP Madgett, and Stoneman # 1 and #2 units.

Madison Gas and Electric indicated the heat rate information is appropriate for their units. We-Energies initially requested a confidential treatment before providing updates to start-up cost data and subsequently determined that the data provided by MISO was acceptable.

v. Operational Constraints: Unit Downtime, Runtime and Ramp Rates

PowerBase utilizes RDI's BaseCase as the main source of unit Operational Constraint information.

Dairyland Power Cooperative/Gensys, Madison gas & Electric and We-Energies provided updates or revisions to the operational constraint information. There were a large number of updates for the units in We-Energies. All updated information was incorporated in the database.

vi. Maintenance Schedules

PowerBase utilizes unit availability and maintenance data by unit type published in the NERC GADS database, supplemented by information from RDI's BaseCase.

Dairyland Power Cooperative/Gensys, Madison Gas & Electric and We-Energies provided updates or revisions to the maintenance schedule information distributed to the companies. Updates or revisions were incorporated in the database.

vii. Operating Reserves Status for the Unit

Each generating resource is designated as providing either quick start or spinning reserve based on unit type. Within MISO, specific operating reserve constraints are specified for individual control areas based on information supplied to MISO by operating entities. For other regions, operating reserve requirements were specified at the regional level based on regional reliability criteria.

Dairyland Power Cooperative/Gensys, Madison gas & Electric and We-Energies provided updates or revisions to the operating reserves information. Changes were incorporated in the database.

viii. Must Run Status

Dairyland Power Cooperative/Gensys, Madison gas & Electric and We-Energies provided updates or revisions to the must run status information. Changes were incorporated in the database.

ix. Emission and Control Allowance

PowerBase utilizes RDI's BaseCase and U.S. EPA data as sources for unit emission rates. Emission allowance / credit price forecasts are obtained from RDI.

Madison Gas Electric provided emission data for the Blount, Columbia, and West Marinette power plants. This information was incorporated into the database.

E. Load Forecasts

Load and demand forecasts represent forecasted control area load and demand. Initial forecasts were developed based on the combination of the Form EIA 714 filings, NERC Energy Supply & Demand (ES&D) data, and NERC regional summer/winter assessments. Control area peak and energy forecasts within a NERC sub-region are scaled to match the total sub-region monthly peak and energy forecast provided in the NERC ES&D database. This scaling is done based on the relative peak and energy values provided in the Form EIA 714 forecasts. This preserved the relative forecasted growth rates of different areas within a sub-region while still recognizing the NERC sub-region forecast which has broader acceptance and credibility. Subsequently, Alliant Energy, Dairyland Power Cooperative, Madison Gas & Electric, and Wisconsin Public Power provided updated monthly energy and demand forecasts; these were incorporated. Within a month, hourly load shapes are based on the latest 714 data or where available ISO data.

This scaling also will be applied to the location specific load profiles in the power flow case to determine loads assigned to specific buses.

Forecasted loads include average transmission losses. For purposes of calculating LMP, marginal losses will be calculated by the model.

Based on comments from Wisconsin Public Service, we reviewed our forecasts in comparison to load forecasts reported by RDI. After consultation with RDI, it was determined that the RDI numbers contained errors and no adjustment was made to our initial forecast.

Additionally, WPPI provided a breakdown of loads between loads by location. We reviewed the definition of the affected load zones and made appropriate adjustments.

F. Unit Operation and Dispatch

MISO provided the Wisconsin utilities an initial list of units that contained approximately 7200 MW of capacity for which the listed operator was a small utility or independent producer (not a control area) and/or for which the operating profile was unknown. The companies were asked to assist MISO in determining how these "orphan units" are committed or dispatched.

Alliant provided information for many of the units initially located within the Alliant East and West control areas, indicating that 47 units (1052 MW) in the Alliant West area were dispatched by municipal utilities, with no further information on operating profiles being provided. All of the units in Alliant East were assigned to a dispatch entity, including those with shared ownership such as Castle Rock that Wisconsin Power and Light, Wisconsin Public Service, and Consolidated Water and Power own in equal thirds. Alliant noted the fact that it operates Castle Rock and will operate the new Riverside Energy Center. Alliant also indicated that the Neenah plant is operated by We-Energies and that the Berlin unit is a landfill gas unit and therefore is not dispatchable.

Dairyland that it dispatched the units that were originally listed as in its control area, except for Barron, Clam River, Danbury Dam and Frederic Diesel plants. Dairyland also identified 29 MW of capacity that it dispatched in units that are under contract to DPC.

WPPI provided information that Mosinee Paper and Packaging Corporation of America are in the Wisconsin Public Service control area and that Stiles Hydro and Scott Worldwide Oconto Falls are in the We-Energies control area.

After review of the information provided by the Wisconsin utilities, additional research was performed to identify dispatching entities for the remaining "orphan units" based on owner press releases supplemented by information from MISO sources. As a result, we were able to identify an appropriate operating entity for more than 82% of the orphan capacity. The remaining 1316 MW of orphan capacity was allocated in the control area in which these units were located.

Madison Gas and Electric provided information on the shared ownership of the Columbia power plant, which corresponds to 22% MG&E, 46% WPL, and 32% WPS. Alliant East is operates this plant. Wisconsin Public Power provided information indicating it has 20% ownership in Boswell, with Minnesota Power owning the remaining 80%. To model the joint ownership of these facilities, Columbia and Boswell were split into fractional units prorating the capacity assigned to each owning entity. This approach ensured that these units were utilized in accordance with each owner's cost structure. The units' maximum capacity, minimum capacity, capacity blocks for heat rate curves, ramp rates, fixed O&M costs, and start costs were split based on ownership share ratios. The units were modeled to ensure coincident unit starts, shutdowns, and outages in each of the fractional units.

G. Power Flow and Transmission Representation

Transmission system configurations, capabilities, and power flow distributions were based on a 2005 power flow case. The 2005 case was developed based on updating the Midwest ISO's 2004 peak power flow case to reflect transmission improvements, topology changes, and load growth for 2005. Data was provided by ATC on behalf of ATC member utilities. And, information was provided by the MISO transmission planning group, Northern Indiana Public Service, and Alliant West on additional transmission improvements including improvements outside Wisconsin. Dairyland Power Cooperative reviewed the power flow case and indicated that it captured all planned improvements in its footprint. Data provided by these organizations was incorporated in the development of the updated power flow case.

Dairyland Power Cooperative provided information on additional flowgates and these flowgates were monitored during the model runs. Additionally, MISO performed a full AC power flow analysis to identify any additional elements that might be placed at risk due to changes in power flows in market environment. Based on the results of this analysis the following additional flowgates were defined and included in our analysis:

- Prairie Creek Industrial to Bertram 161kV
- Boone to Boone Junction 115kV
- Boone Junction 161/115kV XFRMR
- HenryCO5 161 to Denmark 161kV
- Pleasant Prairie 4 to Bain 345/138 kV XFRMR
- Skanawan to Eastom 115 kV
- Weston to Sherman 115kV
- Pleasant Valley to Saukville 138kV
- Jefferson to Lakehead Cambridge 138kV
- Oak Creek 230/345kV XFRMR
- Paris to St. Martin 138 kV
- Bain 5 to Bain 4 138 kV
- Jefferson 5 to Jefferson 4 138 kV

Additional PROMOD diagnostics will be checked to determine if other elements may be affected by changing power flows.

To implement the power flow case in PROMOD IV, each generating unit was mapped to its appropriate transmission bus. The load busses for each control area and FTR holder were identified and the hourly load forecast for the control area and entity was assigned to its specific load busses.

PROMOD IV represents the full power flow case in standard PSSE version 26 format and implements a linearized solution to the power flow. Shift factors are calculated to represent the redistribution of power flows associated with changes in generator output or load at specific locations.

The model optimizes the dispatch of the system, subject to a set of transmission constraints that represent the financially significant constraints that might be binding on the system dispatch. These transmission constraints comprise both base flow constraints, representing path based flowgate limits, and contingency constraints, reflecting limits based on the flows that would occur in the event of a failure of one or more other specified transmission elements. Contingency constraints occur where the failure of the secondary element(s) would increase flows over the primary flowgate to levels in excess of its security limit. The resulting economic dispatch will be such that, if any of those specified contingencies were to occur, the power flow would still be feasible. The list of potentially binding constraints used in this analysis includes approximately 720 constraints, including over 300 contingency events.

H. Marginal Cost Pricing

The analysis is based on a conventional analysis of LMP pricing. Given that Wisconsin is a cost of service jurisdiction and most of the generation in the state will be committed to serving Wisconsin load on a cost of service basis, Wisconsin generators have a financial incentive to submit bids in the LMP market that reflect their marginal costs.

I. Representation of Contracts

Based on input from stakeholders that their primary concern related to current power contracts was a concern over transmission rights to reach generation located outside Wisconsin, not a desire to model contractual commitments for specific generators to be dispatched to serve Wisconsin load, we have not modeled specific power purchase agreements. The model will purchase the least cost economy energy available in each hour to serve Wisconsin load. Assuming existing contracts are cost-effective and adequate transmission capacity is available, the hourly transactions developed in the model should encompass and may outperform existing power contracts.

The market will alleviate some transmission congestion. And, the ability of parties to offset congestion costs when purchasing over a congested portion of the grid will be reflected in FTR allocations. Our FTR analysis should address the financial implications of stakeholder concerns regarding transmission rights.

J. ATC Redispatch Procedures

ATC has adopted redispatch procedures that take effect during TLR 5 and some TLR 4 events. It is difficult to directly model a procedure that is applied in some but not all instances of congestion. Nonetheless, we wanted to recognize the ATC's redispatch procedure. To do so, the applicable hurdle rate between ATC companies outside the Midwest market was lowered from $3 / MWh to $2.50 / MWh. The $2.50 figure was selected because the initial hurdle rate is already low and the ATC procedure applies in a minority of all TLR events.

REQUEST:

63. Referring to page 68, line 24 of Dr. McNamara's testimony, please explain what is meant by the phrase "generation centric perspective"?

RESPONSE:

LG&E/KU witness Tierney focuses on "access to relatively low- and stable-priced indigenous primary fuels to generate power in local power plants" and "a relatively low-cost portfolio of power plant ages and technology types" as being "a defining feature of electric industry regulatory policy" with respect to the adoption of "centrally organized wholesale power markets." To focus on low cost generation fuels and plant types as an explanation for whether it may make sense to organize regional power markets that are integrated with transmission operations is to take a "generation centric perspective" on the potential benefits and costs of regionally coordinated transmission operations.

Witness: Ronald McNamara