Exhibit No.
Issue: Request for Approval to Join MISO
Witness: Robert Janssen
Sponsoring Party: Dogwood Energy, LLC
Type of Exhibit: Surrebuttal Testimony
Case No.: EO-2008-0046

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	))))))	Case No. EO-2008-0046

SURREBUTTAL TESTIMONY OF

ROBERT JANSSEN ON BEHALF OF

DOGWOOD ENERGY, LLC

Carl J. Lumley, #32869
CURTIS, HEINZ, GARRETT & O'KEEFE, P.C.
130 S. Bemiston, Suite 200
Clayton, Missouri 63105
(314) 725-8788
(314) 725-8789 (Fax)
clumley@lawfirmemail.com

ATTORNEYS FOR DOGWOOD ENERGY, LLC

~~STATE OF~~ District of Columbia)
~~COUNTY OF~~ ________) SS.

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AFFIDAVIT OF ROBERT JANSSEN

COMES NOW Robert Janssen, of lawful age, sound of mind and being first duly sworn, deposes and states:

1. My name is Robert Janssen; I am Vice President for Kelson Energy, Inc., the corporate parent of Dogwood Energy, LLC.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony in the above-referenced case.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge, information and belief.

Robert J Janssen
Robert Janssen

SUBSCRIBED AND SWORN to before me, a Notary Public, this 27th day of February, 2008

Graciela V Baten
Notary Public

My Commission Expires:
(SEAL)

GRACIELA V. BATEN
Notary Public District of Columbia
My Commission Expires October 15, 2008

Surrebuttal Testimony of Robert Janssen
on Behalf of Dogwood Energy, LLC
EO-2008-0046
February 27, 2008

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SURREBUTTAL TESTIMONY OF ROBERT JANSSEN ON BEHALF OF DOGWOOD ENERGY, LLC

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. ARE YOU THE SAME ROBERT JANSSEN THAT PREVIOUSLY SUBMITTED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. AS WITH YOUR REBUTTAL TESTIMONY, DO YOU HOLD THE OPINIONS YOU EXPRESS IN THIS TESTIMONY TO A REASONABLE DEGREE OF CERTAINTY AS AN EXPERT REGARDING ELECTRICAL POWER GENERATION AND TRANSMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the rebuttal testimonies of Mr. Volpe on behalf of the City of Independence ("Independence"), Messrs. Doying and Pfeifenberger on behalf of the Midwest ISO ("MISO"), and Dr. Proctor on behalf of the Commission Staff. The first three gentlemen reach conclusions in their rebuttal testimonies that are based on inaccurate information and assumptions that I correct in this testimony. In reaching their conclusions, Messrs. Volpe and Pfeifenberger also fail to consider the significant risks that Aquila would incur if it were to join MISO rather than the Southwest Power Pool

("SPP"), which would effectively leave Aquila unable to realize the full potential membership benefits of MISO. I also provide additional information on some topics discussed by Dr. Proctor.

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A. My testimony addresses five major topics for the purpose of correcting inaccurate statements or assumptions by other witnesses in this proceeding and discussing risks that Aquila would incur by joining MISO rather than SPP. Those topics are:

a. Dogwood Energy's ("Dogwood's") Operational History;
b. SPP's EIS Market Operations and Costs;
c. MISO Market Scope;
d. Other Non-Production Cost RTO Benefits; and
e. RTO Seams Issues Impacts.

In summary, regarding Dogwood's operational history, I provide details regarding the operations and history of the plant and explain why it is unreasonable for Mr. Pfeifenberger to rely upon Dogwood's generating output for 2006 and a portion of 2007 as corroborating evidence to support some of his assertions regarding the Aquila Study.

Regarding SPP's EIS Market operations and costs, I describe the fundamentals of SPP's EIS Market and explain how they are similar to and/or differ from those of the real-time markets of other RTOs and ISOs. Based upon that information, it is clear that Messers. Volpe and Pfeifenberger make erroneous statements and comparisons between SPP's and MISO's markets in their testimonies. In particular, Mr. Volpe's comparisons regarding the future administrative costs of MISO and SPP in his testimony and his response to Data Request No. ILA-002 IND are unreliable as a result of his incorrect assumptions regarding the SPP EIS Market and his erroneous interpretation of SPP's administrative cost accounting.

Regarding the scope of MISO's markets and their availability to Aquila Missouri ("Aquila"), I rebut Mr. Volpe's statements as overbroad and unsupported since he did not consider the fact that the economic supply of power must take into account the cost of transmission congestion regardless of the overall size of an RTO market.

Finally, I discuss the RTO seams issues that would be created if Aquila joined MISO and the consequent risks that would be incurred by both Aquila and other adjacent utilities in Missouri. I agree with Dr. Proctor that if Aquila joins MISO, a robust seams agreement between MISO and AECI would be a necessary precondition. In my testimony, I also discuss the transmission system constraints (flowgates) that exist within and around Aquila and explain the potential risks that would be created if Aquila joined MISO rather than SPP. Failure to adequately resolve these seams would create significant uncertainties regarding whether Aquila would be able to obtain any of the projected benefits from joining MISO. As a result, I conclude that an expanded arrangement between SPP and MISO that includes cost allocation for generation redispatch over the potential new SPP /

MISO border between Aquila Missouri and KCP&L would be needed in addition to a more robust seams agreement between MISO and AECI if the Commission were to approve Aquila's request to join MISO.

II. DOGWOOD ENERGY'S OPERATIONAL HISTORY

Q. TO WHAT TESTIMONY DO YOU WISH TO RESPOND REGARDING DOGWOOD ENERGY'S OPERATIONAL HISTORY?

A. In his Rebuttal Testimony, Mr. Pfeifenberger reaches the conclusion that "the larger SPP benefits as well as the large displacement of Aquila Missouri generation in the SPP case are driven almost entirely by the Aquila Study's assumptions and results for the commitment and dispatch of a single merchant power plant ... in Aquila's control area." (Pfeifenberger Rebuttal at p. 4, lines 8-11). That plant is the Dogwood Energy generating facility.

As a result, Mr. Pfeifenberger states that "[t]he bottom line is that the Aquila Study incorrectly overstates the estimated benefits of Aquila being in SPP relative to the benefit of Aquila joining the Midwest ISO." (Pfeifenberger Rebuttal at p.11, lines 11-12).

In support of this conclusion, Mr. Pfeifenberger presents what he calls "several pieces of clear and corroborating evidence", that he relies upon to substantiate his assertions. (Pfeifenberger Rebuttal at p. 11, lines 13-16). First, he compares the simulated dispatch of the Dogwood facility in 2008 for the three cases presented in the Aquila Study with the actual historic generation of the plant. He presents this information in Figure 1 of his Rebuttal Testimony on page 12.

Based on his review of the 2006 and 2007 year-to-date generation data, Mr. Pfeifenberger concludes that the market simulation of the "Aquila Stand Alone" and the "Aquila in MISO" study cases resulted in "substantially greater dispatch of the [Dogwood] plant than the dispatch levels the plant ... actually experienced in 2006 and 2007." He also concludes that the Aquila in SPP case "resulted in a simulated [Dogwood] dispatch that is close to the plant's actual operations during 2006." (Pfeifenberger Rebuttal at p. 12, lines 2-7).

Mr. Pfeifenberger's comparison of the 2008 simulation results of the Aquila Study cases to Dogwood's historic operations is flawed due to the operating history of the Dogwood plant. As a result, the "clear and corroborating evidence" that Mr. Pfeifenberger relies upon does not provide such corroboration.

Q. PLEASE EXPLAIN THE HISTORY OF THE DOGWOOD ENERGY GENERATING FACILITY.

A. The generating facility now owned by Dogwood Energy, LLC was originally constructed in 2001 as a joint venture between Aquila and Calpine and was called the Aries plant. The plant's full combined cycle output was available to the market in 2002. Aquila pulled out of the venture in March 2004, and its power purchase agreement with the plant expired at the end of May 2005. For unrelated reasons, Calpine filed for bankruptcy in December 2005. Approximately two years later, the "Aries" plant was put up for auction by Calpine. Kelson Energy ("Kelson") won the auction, acquired the plant in January 2007, and set up a subsidiary named Dogwood Energy, LLC to hold its interests in the plant.[1]

Q. PLEASE DESCRIBE THE OPERATIONS OF THE DOGWOOD FACILITY AFTER DOGWOOD ENERGY ACQUIRED THE FACILITY?

A. Kelson Energy's due diligence during the acquisition process indicated that while the plant required a significant amount of maintenance and repair, it could be made operational in time to meet the energy needs of the region during Summer 2007. Further, its performance could continue to be improved over time with additional investments. Dogwood spent several months in an extended maintenance outage in early 2007 after being acquired and was made available to the market again in May 2007. The Dogwood generating facility operated reliably to supply its wholesale power customers in the region for the remainder of 2007. Today, Kelson continues to invest in operational enhancements at Dogwood to improve the performance of the facility.

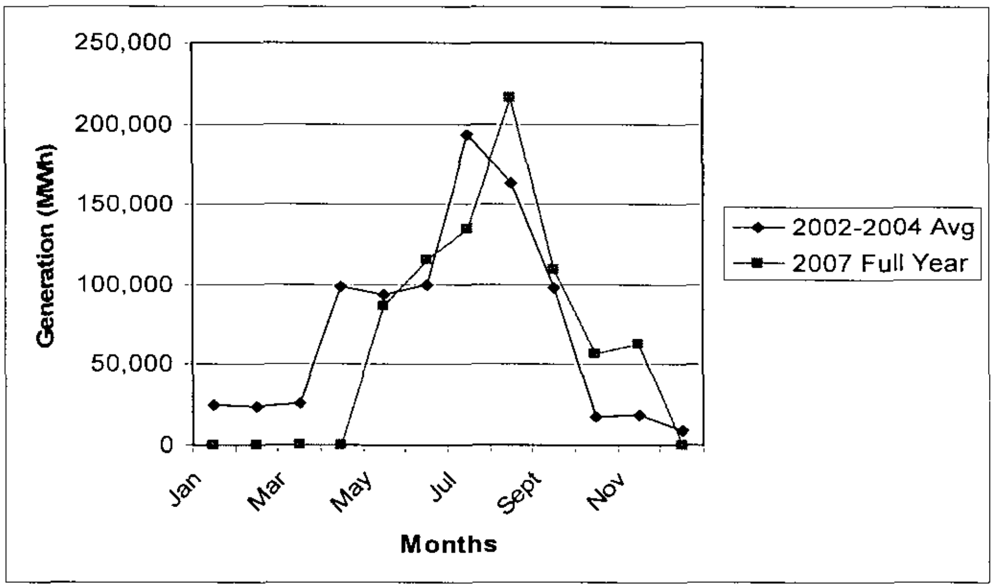
[1] Technically, Cass County, Missouri owns the plant under the bonding agreement and Dogwood leases the facility. However, for purposes of this testimony, I will refer to the plant as being "owned" or "acquired" by Dogwood.

Q. WAS DOGWOOD'S GENERATING OUTPUT IN 2007 UNDER ITS NEW MANAGEMENT CONSISTENT WITH ITS OPERATING HISTORY IN PRIOR YEARS?

A. Its full-year output in 2007 was close to being consistent with the plant's operating history during 2002 to 2004 while it was under a purchase power agreement with Aquila Missouri. Dogwood produced approximately 781,000 MWhs during 2007. This output level was slightly less than the 866,000 MWh output annual average during 2002 to 2004. Part of the reason for the slightly reduced output in 2007 was due to the extended maintenance outage in early 2007. During 2002 to 2004, the plant's output averaged approximately 173,000 MWh during the first four months of each year. The chart below compares Dogwood's 2007 output to its annual average output for the period from 2002 to 2004.

Chart 1

DOGWOOD ENERGY GENERATING OUTPUT



Source: Historical generation data for Dogwood Energy / Aries

However, Dogwood's output in 2007 was not consistent with operations during 2005 and 2006. As mentioned previously, a power sales agreement with Aquila ended in May 2005, and Calpine filed for bankruptcy in December 2005. As a result, the plant's output for both 2005 and 2006 was drastically lower than the previous 2002 to 2004 period and inconsistent with both the previous and current operations of the plant.

Q. WHAT IS THE IMPACT OF THE ACTUAL HISTORY OF DOGWOOD'S OPERATIONS ON MR. PFEIFENBERGER'S RELIANCE ON

DOGWOOD'S GENERATING OUTPUT FOR 2006 AND 2007 AS CORROBORATING EVIDENCE FOR HIS CONCLUSIONS?

A. It means that Mr. Pfeifenberger cannot reasonably rely on Dogwood's 2005 or 2006 generating output as being indicative of any reasonable future operating scenario for the purpose of making conclusions regarding the Aquila Study. Further, I believe that use of the plant's 2007 generating output also is not advisable for benchmarking purposes in comparison to the Aquila Study scenarios, due to the performance improvements planned for Dogwood in the near future and the fact that it was only Kelson's first year of managing and operating the plant.

In addition, Mr. Pfeifenberger incorrectly concludes that "under actual market conditions the [Dogwood] plant generally is not dispatched during the fall, winter and early spring." (Pfeifenberger Rebuttal at p. 12, lines 9-10). Dogwood's operations in 2007 and during the 2002 to 2004 period show that this is simply not true. Mr. Pfeifenberger reached this conclusion based on the aberrant generation output in 2006 and a partial year of data for 2007, which included an extended maintenance outage at the beginning of the year. As shown in the chart above, during 2002 to 2004, slightly more than one-third of Dogwood's output occurred during the period from September to April, which is the period that I interpret as being consistent with the fall, winter and early spring period referenced by Mr. Pfeifenberger.

III. SPP'S EIS MARKET OPERATIONS AND COSTS

A. SPP EIS MARKET OPERATIONS

Q. TO WHAT TESTIMONY DO YOU WISH TO RESPOND REGARDING SPP'S EIS MARKET OPERATIONS?

A. I wish to respond to the testimony of City of Independence and MISO witnesses. These witnesses do not provide an accurate description in their testimonies of the type of energy market SPP has developed and operated for over a year. Therefore, certain conclusions they reach are incorrect.

First, Mr. Volpe states on pages 6-7 of his Rebuttal Testimony that:

> [t]he current SPP energy market consists primarily of a market for imbalance energy. Imbalance energy is the difference between the amount of energy that actually flows from each generator and to each load, and the amount that was prearranged through schedules. This is in contrast to Midwest ISO Day-Ahead and Real-Time security constrained markets where Network Resources are required to submit offers to supply their generation in the Day-Ahead Energy market. The major difference between the SPP model and the Midwest ISO's market is that there is no financially binding Day-Ahead market within SPP's market design and the majority of the transactions in SPP occur on a bilateral basis because there is no centrally administered market as there is in the Midwest ISO. Furthermore, in SPP there are no Financial Transmission Rights to provide customers with the opportunity to hedge against the costs of congestion in a Locational Marginal Price based market as is the case in the Midwest ISO. SPP thus still utilizes TLRs to address congestion, rather than the Midwest ISO's use of congestion charges based on locational marginal pricing and Financial Transmission Rights (FTRs) to enable hedging against congestion charges.

As I will discuss further below, based on the incorrect and contradictory statements he makes above regarding SPP's energy imbalance (EIS) market, it is clear that Mr. Volpe does not understand the details of how it operates. Further, in his analysis of RTO administrative costs in response to Data Request No. ILA-002 IND (copy attached hereto as Schedule RJJ-4), Mr. Volpe erroneously excludes any cost of an existing energy market in SPP from his analysis, even though Mr. Volpe acknowledges in his testimony, as stated above, that one does exist.

Similarly, Mr. Pfeifenberger states that SPP's current market structure is a Day-1 design that would continue to exist for at least several more years. (Pfeifenberger Rebuttal at p. 24, lines 4-8). He continues by stating:

> Until SPP implements a Day-2 market design, however, certain inefficiencies in unit commitment, generation dispatch, and congestion management would continue to exist within the SPP footprint. These inefficiencies – which include suboptimal utilization of the transmission system in the absence of market-based congestion management – would mean higher total generation costs compared to a Day-2 market design.

Mr. Pfeifenberger also states that:

> The Midwest ISO market, featuring a day-ahead and real-time energy market with centralized unit commitment and dispatch, is sometimes referred to as a "Day-2" market. By contrast, the current SPP market is sometimes referred to as a "Day-1" market. The Midwest ISO evolved from a Day-1 market to a Day-2 market on April 1, 2005. (Pfeifenberger Rebuttal at p. 5, footnote 2).

Because one of the primary distinctions between a Day-1 RTO and a Day-2 RTO is that a Day-1 RTO lacks energy markets, including a real-time (or "same day" market), these statements by Mr. Pfeifenberger could be contradictory and misleading. While he acknowledges that SPP has an energy imbalance market, he does not accurately state how such a market operates or fits in with a Day-2 RTO design.[2] Further, Mr. Pfeifenberger acknowledged in response to a data request that he is not familiar with SPP's market operations.[3]

Q. DOES DR. PROCTOR DISCUSS THE SPP ENERGY MARKET IN HIS REBUTTAL TESTIMONY?

A. Yes, he does. Dr. Proctor states that SPP has a real-time energy market, in contrast to MISO which has both a real-time energy market and a day-ahead market. (Proctor Rebuttal at p. 24, lines 15-16).

Q. DOES DR. PROCTOR DRAW ANY OTHER DISTINCTION BETWEEN SPP'S EIS MARKET AND MISO'S REAL-TIME ENERGY MARKET?

A. Other than stating that SPP and MISO have different systems for financial transmission rights, he does not. (Proctor Rebuttal at p. 24, lines 16-17). Due to his involvement in SPP stakeholder activities, and SPP market development activities in particular, Dr. Proctor correctly describes SPP's EIS Market as a real-time energy market, while the other two witnesses are apparently not familiar with the EIS Market in any great detail and do not seem to understand how an "imbalance" energy market could be a robust, real-time energy market in SPP.

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[2] For additional information, please see Schedule RJJ-5 which contains an excerpt from the Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, October 2004, FERC Docket No. PL04-16-000

[3] See Response 11 in Midwest ISO's responses to Dogwood's Data Requests at Schedule RJJ-6.

Q. WHAT IS YOUR OWN EXPERIENCE WITH SPP'S ENERGY MARKET?

A. I am very familiar with SPP's development and operation of its energy market. For over two years I have represented Redbud Energy in SPP stakeholder groups as a member of SPP and an independent power producer ("IPP") participant in the market. Prior to that, from mid-2004 to late 2005, I was engaged by SPP as part of its external independent market monitoring team to help develop the generation and transmission market monitoring and mitigation plans for SPP, as required by FERC.

Q. PLEASE DESCRIBE SPP'S CURRENT EIS (OR REAL-TIME ENERGY) MARKET.

A. On February 1, 2007, SPP successfully started its Energy Imbalance Service market. It is a real-time energy market that provides region-wide, security constrained, economic dispatch for all generating facilities within SPP's market footprint based on the concept of locational marginal pricing on a nodal basis.

SPP refers to its real-time energy market as an Energy Imbalance Service ("EIS") market because it was originally developed and executed as a replacement for SPP's Schedule 4 OATT tariff for imbalance energy. Because the concept of imbalance energy was retained, that is, variations in generating output from a defined transmission schedule, I have noticed that the name of this market tends to cause confusion because to some it incorrectly implies a limited or negligible energy market based on how imbalance energy service tended to work previously.

All generating facilities that participate in the SPP EIS market offer their dispatchable range to the market in full, thereby allowing SPP, as the market operator, to deploy generating facilities at any point within their dispatchable range based upon region-wide economics, just as in any other real-time energy market. The imbalance nature of the market impacts only the settlement phase of the market when participants' generation and load are settled based on deviations from physical transmission schedules rather than settling all energy or load in the market. This design purposefully emphasizes the continuing importance of bilateral transactions within the SPP region, from both economic and reliability perspectives.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE SPP EIS MARKET WORKS.

A. Let's assume that a natural gas-fired, combined cycle facility is operating and makes its output available to the EIS market for economic dispatch. Further, let's assume that the dispatchable range provided to SPP through the facility's Resource Plan for each hour of the day is between 150 MW and 230 MW.[4]

[4] A Resource Plan is provided by each Market Participant for each registered Resource, which can be generation or controllable load, to SPP on an hourly basis. It includes information regarding the Resource's operating capabilities and whether it is available for economic dispatch by SPP in the EIS Market.

Finally, let's assume that the plant has a combination of firm and/or non-firm power sales backed by physical transmission schedules in the amount of 200 MW. Depending on region-wide generation prices and load levels, SPP will send the facility a deployment signal every five minutes to indicate its target level of generation output. The plant will follow SPP's deployment signals, and at the end of each hour, if its integrated output for the hour is above its 200 MW of transmission schedules, the facility will be paid its nodal EIS Market price (the Locational Imbalance Price ("LIP")) for each MW of its integrated hourly output above 200 MW. Similarly, if the plant's total output for the hour is below 200 MW, it will pay for each MW of output that it did not generate less than that amount. While this is a simplified example and does not address issues such as reserve energy deployment events, uninstructed resource deviation, or transmission service curtailments, it nonetheless provides an accurate portrayal of the essence of the day-to-day operations of SPP's EIS Market.

In summary, the real-time EIS market is substantially similar to the real-time energy market of any other RTO or ISO operating in the United States today. A generator is centrally dispatched based on offered prices, and it can be deployed by the RTO at any point within its dispatchable range based on the region-wide economics that the RTO sees and translates into a locational marginal price at the generator's pricing node. Any significant differences are either regional in nature, or are due to the fact that SPP uses physical rather than financial transmission rights today to support the functioning of its EIS Market. The physical transmission rights in SPP provide a congestion hedge for both purchasers and sellers of power, even though they do not operate in the same fashion as the Financial Transmission Rights ("FTRs") in MISO or similar variations in other RTO and ISO markets.

Q. PLEASE EXPLAIN IN MORE DETAIL WHY MR. VOLPE'S STATEMENTS REGARDING THE EIS MARKET ARE CONTRADICTORY.

A. In view of my discussion above regarding the SPP EIS Market, Mr. Volpe's description of MISO's markets as being "security constrained" in contrast to SPP's market and his statement that there is no centrally administered market in SPP as there is in the Midwest ISO are simply not accurate. As I described above, SPP's EIS Market is a region-wide, security constrained, real-time energy market. Mr. Volpe further confuses the issue by stating that customers in SPP have no opportunity to hedge against the costs of congestion because they do not have FTRs, when in fact, SPP Market Participants do use their physical transmission rights to hedge such costs under the EIS Market today.

Q. DOES SPP STILL USE THE TRANSMISSION LOADING RELIEF ("TLR") PROCEDURE AS ASSERTED BY MR. VOLPE?

A. Yes, but Mr. Volpe does not accurately portray in his testimony the use of TLRs in SPP's EIS market. TLRs in SPP are now the mechanism used to activate the EIS Market's response to a physical transmission constraint that could cause a reliability problem. SPP still calls TLRs as it did prior to the start-up of the EIS Market, but the TLR itself no longer controls the operating levels of generators that have offered their output to SPP for economic dispatch. Instead, calling a TLR notifies SPP's market operator(s) that a particular transmission constraint (which is on a flowgate in SPP) needs to be activated for potential economic redispatch due to anticipated congestion on those transmission elements. Therefore, in contrast to Mr. Volpe's statements, the TLR itself has very little impact on controlling congestion in SPP under the EIS market. Instead the TLR largely serves to manage schedule curtailments for the purpose of maintaining a feasible set of transmission schedules. It is the EIS Market's security constrained economic dispatch based on locational marginal pricing, which is separately activated when SPP calls a TLR, that truly manages most congestion in SPP today.

Q. PLEASE EXPLAIN IN MORE DETAIL WHY MR. PFEIFENBERGER'S STATEMENTS REGARDING THE EIS MARKET ARE CONTRADICTORY?

A. As I stated above, Mr. Pfeifenberger discusses in his Rebuttal testimony that certain inefficiencies will continue to exist in SPP until SPP implements a Day-2 market design. He specifically emphasizes suboptimal utilization of the transmission system in the absence of market-based congestion management as one of these inefficiencies. However, as I stated above in response to Mr. Volpe's assertion regarding SPP's use of TLRs, when congestion is encountered in SPP it is now cleared more efficiently using market-based congestion management through SPP's EIS Market than it was by using TLRs alone prior to February 1, 2007.

Also, in his testimony that I referenced above, Mr. Pfeifenberger equates SPP's status as a Day-1 RTO today as being similar to MISO's status as a Day-1 RTO prior to April 1, 2005. This is a misleading statement, because MISO did not operate a real-time energy market, and hence did not utilize market-based congestion management of any sort, prior to April 1, 2005. While SPP today is not exactly a Day-2 RTO since it lacks a Day-Ahead energy market, the congestion management and regional economic dispatch provided by SPP's EIS market still make it a fundamentally different market than MISO's prior to April 1, 2005.

B. SPP EIS MARKET COSTS

Q. TO WHAT TESTIMONY DO YOU WISH TO RESPOND REGARDING SPP'S MARKET COSTS?

A. Mr. Volpe asserts in his Rebuttal Testimony that SPP's administrative costs are likely to be higher for Aquila than they would otherwise be if Aquila were to join the Midwest ISO. (Volpe Rebuttal at p. 5, lines 5-7). He discusses this topic in slightly more detail on pages 10-11 of his Rebuttal Testimony, but he provides no quantification of potential differences in either MISO's or SPP's administrative costs in his testimony. Instead, Mr. Volpe's testimony relies on two assertions, which are that: (a) RTO administrative costs associated with developing and operating an energy market are largely fixed costs and therefore SPP's administrative costs should be higher than MISO's because SPP is approximately 1/3 the size of MISO; and (b) CRA's forecasted administrative costs for SPP and MISO are not comparable and do not contain the same services. His conclusion is that any "[a]djustments that show higher SPP administrative costs and lower Midwest ISO administrative costs would further reduce the difference in total benefits of RTO, thus further eroding the study's implication that SPP participation would be more beneficial than Midwest ISO participation." (Volpe Rebuttal at p. 11, lines 9-13).

Q. HAS MR. VOLPE ATTEMPTED TO QUANTIFY HIS ASSERTIONS REGARDING THE DIFFERENCES IN SPP'S AND MISO'S ADMINISTRATIVE COSTS SINCE HE FILED HIS REBUTTAL TESTIMONY?

A. Yes, he has. In response to Data Request No. ILA-002 IND, Mr. Volpe provided a detailed discussion and set of analyses purporting to show that in the long term, SPP's administrative costs will be approximately 6.3 cents per MWh higher than

MISO's during the period from 2012 to 2017, and presumably beyond. (Schedule RJJ-4 at p. 3).

Q. HOW DO YOU RESPOND TO MR. VOLPE'S ANALYSIS AND QUANTIFICATION OF SPP'S AND MISO'S ADMINISTRATIVE COSTS?

A. Presuming that Mr. Volpe's analysis in response to Data Request No. ILA-002 IND is a proper basis for comparison of the two RTO's costs, which I will not attempt to dispute at this time, it is critical to note that it contains one significant error that when corrected, completely changes the conclusion that Mr. Volpe reaches from his calculations. First, as discussed above in a previous section of my testimony, Mr. Volpe has not taken into account the fact that SPP is operating a real-time energy market. As a result, Mr. Volpe provides SPP with no credit in his analysis for SPP's current operation of such market. (Ibid. at p. 3, Table A).

Q. ARE SPP'S COSTS OF OPERATING ITS REAL-TIME ENERGY MARKET DOCUMENTED?

A. Yes, they are included in the same document from SPP that Mr. Volpe uses to support his conclusions.

Q. PLEASE EXPLAIN.

A. As an exhibit to his response, Mr. Volpe includes a cost breakdown of SPP's administrative charges for 2007 that SPP makes available pursuant to FERC Order No. 668. (Ibid.). This exhibit shows that 9.7 cents per MWh out of SPP's total 19.0 cents per MWh in total administrative charges are allocated to account 575.7, which is titled "Market Facilitation, Monitoring and Compliance Services."

As confirmed by SPP in its response to Dogwood Data Request 1-1 (a copy of which is attached hereto as Schedule RJJ-7), account 575.7 documents the portion of its administrative charges that are attributable to its development and operation of its real-time energy market.

Q. WHAT IS THE IMPACT OF THIS INFORMATION ON MR. VOLPE'S ANALYSIS?

A. This information results in a complete reversal of the conclusion that Mr. Volpe reaches in both his testimony and in his response to Data Request No. ILA-002 IND that SPP's administrative charges should be higher than MISO's in the long run, which would reduce the benefits Aquila would receive if it joined SPP rather than MISO. I have edited Mr. Volpe's analysis in Table A and provided it as Schedule RJJ-8 to show how the results would change if Mr. Volpe had provided SPP with full credit for its costs of operating its EIS Market. This correction shows that instead of SPP's costs being 6.3 cents per MWh higher in 2017 than MISO's, they should be 3.4 cents per MWh less, according to Mr. Volpe's own analysis (under the 20% market implementation cost reduction scenario). As a result, in contrast to Mr. Volpe's assertions, the benefits that Aquila would obtain from joining SPP rather than MISO would increase rather than decrease.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR. VOLPE'S ARGUMENTS REGARDING SPP'S ADMINISTRATIVE COSTS?

A. Yes. While Mr. Volpe's arguments regarding the fixed cost nature of RTOs may seem reasonable from a purely theoretical standpoint, he misses the mark on some extremely important real world issues and consequently draws incorrect conclusions regarding economies of scale or lack thereof for SPP.

The first point is his erroneous implicit assumption that SPP's size and boundaries will remain static in comparison to MISO. Over the past decade, the boundaries of RTOs, including MISO and SPP, have not been constant. The trend has generally been toward increases in size and scope. While there will be utilities that are likely to stay out of organized regional markets, numerous parties that initially remained on the sidelines have seen the benefits and started moving into RTOs, such as PJM, MISO and SPP. In some cases, these parties enjoy full participation right from the start, and in some cases it is a more gradual process, with a utility initially taking some non-market services, and then utilizing additional market-related services over time. Aquila appears to be one potential example of this latter case. In any event, Mr. Volpe's assumption that SPP will always be at a significant disadvantage to MISO when it comes to economies of scale is unsupportable, even in the near-term, much less in the long-term. This is particularly true when one considers the fact that many of the utilities that border SPP are not already full market participants in another RTO, which provides SPP's RTO footprint room to expand without encroaching on the territory of another RTO.

The second point is that Mr. Volpe does not consider that SPP could realize that it might be under pressure to reduce costs and/or increase the benefits it provides, either at its members' urging, state or federal regulators' urging, or simply to remain competitive in providing RTO services, and therefore might take actions to either reduce its costs or increase its revenues from other sources. As one example of this, over the past few years, SPP has been relatively aggressive in marketing its provision of non-market RTO services to non-SPP utilities, and its successes include its current Independent Transmission Organization ("ITO") work for Louisville Gas and Electric / Kentucky Utilities Co and its Independent Coordinator of Transmission ("ICT") work for Entergy. The additional revenues provided by these services supplement those SPP obtains from its own members, thereby reducing SPP's cost burden on its members and reducing SPP's administrative charge on a cents per MWh basis. And, as another example, SPP's administrative charges also include the costs of operating the Regional Reliability Entity for the SPP footprint, which unlike most other RTOs, SPP does in order to provide additional economies of scale for its members and to eliminate duplicative reliability efforts being performed by two different organizations covering the same region of the country, which reduces overall costs to SPP's members.

IV. MISO MARKET SCOPE

Q. TO WHAT TESTIMONY REGARDING THE SCOPE OF MISO'S MARKET DO YOU WISH TO RESPOND?

A. Mr. Volpe states in his Rebuttal Testimony that Aquila's participation in the MISO markets would:

> allow Aquila on behalf of its customers, and the City and other wholesale customers, to access a large geographical region stretching from the Atlantic Ocean to the Rocky Mountains and from Manitoba to the state of Missouri. Access to markets of this breadth and scope, given the City's direct interconnections to Aquila, is superior to the region covered by SPP." (Volpe Rebuttal at p. 5, lines 17-22).

Q. DO YOU AGREE WITH MR. VOLPE THAT THE FULL "BREADTH AND SCOPE" OF THE MISO / PJM COMBINED MARKET WILL BE AVAILABLE TO AQUILA IF IT JOINS MISO?

A. Not on a practical day-to-day basis as I believe Mr. Volpe's unqualified statement suggests. Even in MISO's and PJM's markets, which use FTRs, economic access to power supplies is limited by transmission system congestion. In those markets, a purchaser may be able to schedule energy supplies from any supplier in the market, but the purchase price will economically need to reflect the cost of either acquiring FTRs from the source to the sink for the period of the transaction, or the potential risk of paying for any transmission congestion that adds to the price of the power purchase that was not hedged by the acquisition of FTRs. As a result, the location and duration of transmission congestion limits the distances over which power can be economically purchased even in the MISO and PJM markets.

V. RTO SEAMS ISSUES IMPACTS

Q. TO WHAT TESTIMONY DO YOU WISH TO RESPOND REGARDING RTO SEAMS ISSUES IMPACTS?

A. In his Rebuttal Testimony, Dr. Proctor addresses two important issues regarding Aquila's choice of an RTO, which are transmission interconnections and seams agreements, both of which involve the issue of congestion management. (Proctor Rebuttal at p.4, line 25 to p.5, line 9).

Q. DID CITY OF INDEPENDENCE OR MISO WITNESSES SPECIFICALLY ADDRESS RTO SEAMS ISSUES IN THEIR REBUTTAL TESTIMONIES?

A. No, they did not.

Q. ARE RTO SEAMS ISSUES IMPORTANT?

A. Yes, they are. Failure to adequately address seams issues between adjacent RTOs or between an RTO and any non-RTO utilities adjacent to it can cause RTO members to fail to obtain the full benefits of energy market participation.

Q. WHAT IS YOUR OVERALL RESPONSE TO DR. PROCTOR'S TESTIMONY?

A. I believe that Dr. Proctor's Rebuttal Testimony does a good job of discussing and providing details regarding Aquila's transmission interconnections. (See Proctor Rebuttal at p. 29 to 31 and Schedules 1 and 2). Dr. Proctor uses this information to discuss how critical Associated Electric Cooperative, Inc. ("AECI") is to Aquila's interconnection with MISO. This leads him to correctly conclude that a direct seams agreement between MISO and AECI that addresses Reciprocal Coordinated Flowgates ("RCFs") in a manner similar to that included in the SPP-MISO Joint Operating Agreement ("JOA") is a necessary precondition to Aquila joining MISO. (Proctor Rebuttal at p. 34-35).

Q. DO YOU AGREE WITH DR. PROCTOR THAT SUCH A SEAMS AGREEMENT IS NECESSARY?

A. Yes. In general, adequate seams agreements between RTOs and neighboring RTOs or utilities are needed to avoid unnecessary adverse impacts across the "seam" or border between the two entities. The issues to be addressed in such seams agreements can vary depending on the level of market development in each of the two entities, as well as the nature of the seam between the two entities. For MISO and AECI, a market to non-market seams agreement containing terms consistent with resolving the types of parallel power flow issues that Dr. Proctor discusses would be appropriate. A seams agreement that addresses reciprocal coordination of flowgates would seem to be the right level of seams agreement between these two entities, in addition to the more basic seams agreement terms in the existing market-to-non-market MISO / TVA seams agreement. The next level of seams agreement development beyond RCFs is a market-to-market congestion management process called an Interregional Coordination Process or "ICP", such as in MISO's seams agreement with PJM.[5] The ICP allows financial compensation between two market-to-market regions that permits redispatch of generation in one region to occur and be compensated for the purpose of solving congestion in the other region. This additional step beyond the CMP use of RCFs between two market-to-market regions brings additional market-based congestion management efficiencies to the seam between two RTOs by allowing congestion to be solved by the lowest-cost resource regardless of the RTO in which that resource is located.

Q. DO YOU BELIEVE THAT AN ICP PROTOCOL SHOULD BE INCLUDED IN THE SEAMS AGREEMENT BETWEEN MISO AND AECI?

A. Since a RTO-type energy market is not currently being operated in AECI, it is not clear that including an ICP protocol in a seams agreement between MISO and AECI is reasonable or necessary. However, if the concept could be adapted to the MISO – AECI seams agreement in a market-to-non-market context, it could

[5] RCFs are part of a broader market-to-non-market congestion management process in both the SPP-MISO and MISO-PJM seams agreements that is simply called the Congestion Management Process or "CMP". The ICP builds upon and enhances the CMP.

further reduce the risks of Aquila joining MISO and possibly increase the efficiencies of Aquila's participation in the MISO markets. Therefore, I recommend that a version of the ICP concept be considered as part of the Stipulation and Agreement process advocated by Dr. Proctor in the event that the Commission chooses to approve Aquila's application to join MISO.

Q. DO YOU HAVE ANY FURTHER RESPONSES TO DR. PROCTOR'S REBUTTAL TESTIMONY?

A. Yes. Dr. Proctor does not limit his recommendation on seams agreements to only address the need for an agreement between AECI and MISO that addresses RCFs. Dr. Proctor states that the conditions that should be addressed in a Stipulation and Agreement in this proceeding should include, "seams agreements involving all Missouri utilities, but specifically between MISO and AECI." (Proctor Rebuttal at p. 37, lines 28-29). I believe that another important seams agreement that may need further revision is the JOA between SPP and MISO.

Q. PLEASE EXPLAIN.

A. Dr. Proctor recommends further enhancement of the existing indirect seams agreement between MISO and AECI due to the transmission connectivity AECI has with both Aquila and MISO and the resulting parallel power flows anticipated over AECI's transmission system that would result from Aquila joining MISO. (Proctor Rebuttal at p. 31, lines 5-7). Similarly, if Aquila were removed from

SPP's current tariff administration footprint and congestion management processes and included in MISO's, Aquila's transmission interconnections with SPP of fourteen lines totaling 5,915 MVA could require an enhancement to the SPP / MISO seams agreement in order for the two RTOs to effectively coordinate congestion management in a fashion that would not detract from the efficiencies that other Missouri utilities adjacent to Aquila, such as KCP&L, obtain from the SPP EIS Market. This is particularly true because the Aquila utility territory splits KCP&L's in two with one portion of KCP&L being located to the east of Aquila that would be separated from the rest of SPP.

Furthermore, I have reviewed approximately a dozen different flowgates listed on SPP's OASIS that are within or adjacent to Aquila Missouri's territory. (See Schedule RJJ-9). For approximately one-half of those flowgates, the generating facilities located in utilities such as KCP&L, Westar and the Kansas City Board of Public Utilities are important, if not critical, to managing congestion over those flowgates.[6] In my opinion, this means that in addition to the existing RCF protocols included in the current SPP – MISO seams agreement, the Commission should also be concerned that without the ICP economic dispatch enhancement discussed above, there could be significant inefficiencies and adverse economic

[6] This flowgate analysis was developed using PowerWorld Simulator software and performing transfer distribution factor ("TDF") analyses on a SPP powerflow study case. For modeled flowgates with monitored elements at the 345 kV and 161 kV voltages, I used a 10% and 5% TDF cutoff, respectively, for determining the location of generation that contributed significantly to powerflows on each flowgate. Similarly. To eliminate transaction sink-related bias in the analyses, I adjusted the resulting TDF curves to set the median TDF value at the neutral value of 0%.

impacts across the new SPP – MISO RTO seam that would be formed at the current borders of the Aquila Missouri, KCP&L and Westar utility territories.[7]

Q. WOULD YOU SUPPORT AQUILA'S APPLICATION TO JOIN MISO IF THESE PRECONDITIONS REGARDING THE AECI-MISO AND SPP-MISO SEAMS AGREEMENTS ARE MET?

A. No, I am not expressing support for the application through the recommendation of these preconditions. I do not believe that the further development of the seams agreement between MISO and SPP will lead to better congestion management in the region if Aquila joins MISO rather than SPP. I am simply recommending that if the Commission does approve Aquila's application to join MISO, then it should require further development of the seams agreement between SPP and MISO along with the development of a seams agreement between MISO and AECI as Dr. Proctor recommends.

Q. PLEASE EXPLAIN.

A. While these seams agreement enhancements would reduce the significant risks of Aquila's participation in MISO related to the lack of transmission interconnectivity between Aquila and MISO, such enhancements would not eliminate these risks. For example, the RCF provisions of an agreement between

[7] I do not include the City of Independence in this discussion of seams issues, but since Independence is located between KCP&L and Aquila Missouri, any seams issues that it will have should also be addressed. However, since Independence has not indicated whether it will join the SPP market or the MISO market or continue to stay out of both markets, it is not clear at this time whether the City's seams issues will need to be resolved in a market-to-non-market or market-to-market fashion.

MISO and AECI would allow MISO to effectively obtain control over a portion of the flows over AECI's transmission system for use in operating an energy market in Aquila. However, since the limits on MISO's use of those flowgates would likely be established by historical rather than anticipated future power flows, those limits may not be adequate to meet the future demands for power flows between Aquila and the rest of MISO after MISO begins dispatching generating facilities in Aquila's territory based on a MISO-wide security constrained economic dispatch. If MISO does not receive a large enough allocation of the RCFs in AECI, then the benefits that Aquila's customers would receive from Aquila's participation in the MISO market would be limited, unless Aquila purchases additional transmission service across the AECI system (if it is available) to allow for increased flows between the two regions.[8] However, this purchase of transmission would create another cost that could offset the benefits that Aquila would receive from the MISO market, as Dr. Proctor references in his Rebuttal Testimony. (Proctor Rebuttal at p. 31-32).

Q. ARE THERE ANY OTHER RISKS OF AQUILA'S PARTICIPATION IN MISO THAT ARE NOT ADEQUATELY ADDRESSED BY THE SEAMS AGREEMENTS PREVIOUSLY DISCUSSED?

[8] The lack of such transfer capability could specifically result in MISO determining that there is a lack of deliverability for generating units in Aquila into the rest of the MISO market. At this point, MISO has not performed any deliverability tests for generating facilities within Aquila's utility territory, and cannot guarantee whether they would be able to deliver any or all of their output to the rest of the MISO market. (See Schedule RJJ-10).

A. Yes, since Aquila's direct transmission connection to MISO would continue to be through Ameren, Ameren's continued participation in MISO would be a critical factor to Aquila's participation in MISO. Without Ameren's participation in MISO, which is currently being reviewed in another proceeding before this Commission, there is a significant risk of Aquila being severely cut-off from MISO and effectively "islanded", which would most likely eliminate MISO's ability to effectively operate an energy market in Aquila.

Q. PLEASE EXPLAIN THE TERM "ISLANDED" IN THE CONTEXT OF RTO PARTICIPATION.

A. "Islanding" occurs when an RTO participant becomes sufficiently removed or disconnected from the RTO that the RTO's ability to control power flows over critical transmission constraints is impaired. This prevents the RTO from effectively or efficiently operating an energy market within that "islanded" participant.

Q. DO YOU KNOW OF ANY EXAMPLES OF THIS?

A. Yes, though these examples are actually of participants that have not been included in an RTO's market due to the potential for "islanding", rather than parties that did participate and were "islanded" as a result. Specifically, there are SPP members in Southern Louisiana, such as the City of Lafayette and the Louisiana Electric Power Authority, that have expressed a desire to participate in

SPP's EIS Market. However, they have been unable to do so for two reasons. The first of which is that these SPP members are remote enough from the main body of the SPP system, since they are embedded within the Entergy Balancing Authority which does not participate in the SPP EIS Market and does not have a seams agreement addressing Reciprocal Coordinated Flowgates with SPP, that it would be difficult for SPP to effectively control the power flows over key flowgates that would allow these SPP members to participate in the EIS Market. In addition, another SPP member, Cleco Power, provides the primary direct transmission connections between these two SPP members and the rest of the SPP system. However, Cleco does not participate in the EIS Market at this time either. Therefore, with their direct interconnections to the SPP EIS Market footprint cut off, and since they are surrounded by Entergy-controlled flowgates that SPP cannot control effectively, these two SPP members have been "islanded" from the EIS Market footprint and have been unable to directly participate in the EIS Market.

Q. IS THIS THE ONLY WAY THAT "ISLANDING" COULD OCCUR?

A. No. There are more routine issues such as transmission line maintenance outages that could potentially result in one or more key transmission lines being taken out of service and thereby reducing or effectively eliminating the ability for a market to operate efficiently for a period of time in a location that is remote from the main body of an RTO market. This is a more temporary "islanding" condition than the one discussed above, but certainly no less real. In either situation, if such "islanding" occurred with Aquila in MISO, the result would be that Aquila would absorb the costs to participate in MISO without obtaining the full benefits thereof, or in a worst-case scenario, could incur significant congestion costs as well.

Q. WOULD THESE SEAMS RISKS CONTINUE TO BE SIGNIFICANT IF AQUILA JOINED SPP RATHER THAN MISO?

A. No, they would not. First, the risk of "islanding" would be dramatically reduced if Aquila joined SPP rather than MISO. Second, the need for improvements in the SPP-MISO seams agreement would be reduced since Schedule RJJ-9 shows that generation in the MISO market footprint is important to the resolution of congestion over only one flowgate out of the dozen that I evaluated within or adjacent to the Aquila Missouri utility territory. Finally, while RCF congestion management enhancements to the existing SPP-AECI seams agreement would likely be beneficial, they are by no means as critical as those proposed by Dr. Proctor for a MISO-AECI seams agreement since AECI's service territory is not located between the main body of SPP and Aquila as AECI is for Aquila and the main body of MISO.

VI. CONCLUSIONS AND RECOMMENDATIONS.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS TO THE COMMISSION.

A. As a starting point, the recommendations from my Rebuttal Testimony have not changed. Those recommendations are that:

- Aquila and its customers should join an RTO and realize the many benefits that attend such membership;
- The Commission should not be constrained by Aquila's prior commitments and should require Aquila to join SPP rather than MISO; and
- If the Commission approves the pending application for Great Plains Energy ("GPE") and Aquila to merge, then the Commission should require Aquila to join SPP and operate its generation and transmission facilities under the auspices of the SPP RTO as soon as possible (and within four months after approval of the merger.)

Further, as explained in more detail in this Surrebuttal Testimony, many of the key arguments of MISO's and the City of Independence's witnesses are based upon errors, misstatements, or misunderstandings regarding Dogwood Energy and its operations, SPP's market operations and costs, and more broadly the risks that Aquila and its customers would not obtain the full benefits from participation in the MISO market. As a result of my analysis of transmission constraints (flowgates) in and around the Aquila transmission system, I conclude that there are significant congestion management related-risks associated with seams issues that would result from Aquila's participation in MISO rather than SPP.

Therefore, in addition to the recommendations in my Rebuttal Testimony, I recommend to the Commission that in the alternative, if it approves Aquila's request to join MISO, it should also:

- Require MISO to enter into a seams agreement with AECI that adequately addresses congestion management and parallel power flows over the AECI system between Aquila and MISO, including reciprocal coordination of flowgates;
- Require MISO to enhance its seams agreement with SPP to include a market-to-market Interregional Coordination Process ("ICP") that includes provisions for efficient and effective congestion management across the SPP-MISO seam that would allow congestion to be solved by the lowest-cost resource regardless of the RTO in which is it located; and
- Require MISO to investigate and report back to this Commission regarding the potential for incorporating the market-based congestion management efficiencies inherent in the ICP into the MISO-AECI seams agreement no later than one year after the issuance of the Commission's final order in this proceeding.

I make these alternative recommendations in order to reduce the risk to Aquila and its customers that they will not obtain the available benefits of joining MISO. But again, I also continue to recommend that the Commission reject Aquila's request for approval to join MISO and instead order Aquila to join SPP as soon as reasonably possible.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Case No.: EO-2008-0046

Schedule RJJ-4

Data Request No. ILA-002 IND

AQUILA, INC.
DATA REQUEST

CASE NO. EO-2008-0046
AQUILA DATA REQUEST NO. ILA-002 IND

DATE OF REQUEST: December 12, 2007

DATE DUE: January 1, 2008

REQUESTOR: Paul A. Boudreau

REQUESTED FROM: Mark Volpe

QUESTION: Please provide the following information concerning your rebuttal testimony filing:

A. Page 10, Lines 3 – 17
What percentage of costs associated with developing and operating an energy market are fixed costs?

B. Page 10, Line 19 – Page 11, Line 13
Please provide any analysis that you have performed or had performed to determine the appropriate administrative costs to use in comparing MISO and SPP.

C. Page 10, Line 19 – Page 11, Line 13
What adjustments do you propose be made in the Aquila Cost-Benefit Study to the administrative costs of MISO and/or SPP?

RESPONSE:

A. Based on my experience with the Midwest ISO and my review of the Midwest ISO 2008 Budget Review's full-time equivalents, an estimated percentage of the fixed costs associated with developing and operating an energy market would range from 95 to 97%. Once the costs of developing the energy market have been incurred, these costs are sunk and become fixed costs. Similarly, the incremental systems-related costs for hardware, software and ongoing support personnel become fixed costs. Data storage costs are the primary variable costs.

The Midwest ISO's core business is run primarily by Information Technology (IT), Real-Time/Market Operations, Transmission Management and Market Planning professionals. According to the Midwest ISO's proposed operating budget for next year, the 2008 budgeted full-time equivalents (FTEs) in these areas represent 620 out of 764 positions (81%) (See Exhibit 1, page 9). Other positions related to traditional administrative functions (i.e., Senior Management, Finance, Legal, and Human Resources), which are also fixed costs, increase the total percentage of fixed costs to approximately 95-97%.

B. Table A below depicts the adjusted administrative costs that should be used to compare MISO with SPP for the ten-year period from 2008 through 2017.

As shown on Table A, I recommend two adjustments to the Midwest ISO's administrative cost used by CRA. First, the administrative costs associated with MISO Ancillary Service Market (ASM) need to be backed out of the costs for all ten-years since SPP operates no such market and thus incurs no such costs. MISO's filing in Docket No. ER07-1372-000 indicates that the costs are estimated to be $0.035/MWh.
(see http://www.midwestmarket.org/publish/Document/ 13629d_10f71c31154_-7e6d0a48324a?rev=4).

Secondly, the rate used by CRA should be reduced by 1.0 cent per MWh, which is the cost of the deferrals of start-up costs associated with Midwest ISO's existing energy market. This deferral will be totally amortized at the end of 2011 and will no longer be included in the rate. (Calculated based on the deferral balance at the end of 2005 was $80.8 less $45 in exit fees = $35.8 million or a $7 million dollar per year amortization over five-year time period from 2006 - 2011 divided by 650,847 GWh of MISO load equates to 1.0 per MWh)

SPP's administrative rate should reflect the current level of SPP's actual administrative costs as a starting point, not the Midwest ISO's. The CRA International Cost-Benefit Analysis at page 8 makes an inappropriate and unsupported assumption that, "SPP projects their administrative costs per MWh of market member load at roughly 20% below MISO." The current SPP administrative costs under Schedule 1A for 2007 are 19.0 cents per MWh as depicted in Exhibit 2.
(see https://sppoasis.spp.org/documents/swpp/tariff/SPP_Billing_Breakout_Disclosure.pdf)

The adjustments below use SPP's actual current level of administrative costs as the starting point for the entire ten-year time period because the current SPP Schedule 1A is capped at 20 cents per MWh. As stated in my rebuttal testimony, I believe the earliest year in which the SPP might be capable of implementing energy markets similar to MISO's is 2011. If the SPP was able to implement energy markets at a 20% cost reduction per MWh of market load in three years, I estimate the cost to be 18.0 cents per MWh.

As stated in the CRA analysis, MISO's all inclusive administrative rate of 36 cents per MWh includes 13 cents of Schedule 10 administrative costs attributable to the provision of transmission service (CRA International Analysis at 13) analogous to SPP's Schedule 1A costs of 19 cents per MWh. After backing out these costs, the theoretical SPP rate is 19.5 cents per MWh in 2008 dollars (36.0 - 13.0 - 3.5 = 19.5). If SPP is assumed to experience a 20% cost reduction, the SPP rate reflecting such a reduction would be 15.6 cents per MWh (19.5 * 80%). Since the SPP energy market is at least three years from implementation, I used 18.0 cents per MWh rather than 15.6 cents in order to account for 5% annual inflation, wage increases and the overall increase in the price of IT software development costs and maintenance agreements.

The bottom of Table A includes adjustments to the SPP costs excluding the 20% assumed reduction from MISO's costs at 19.5 MWh cents and includes a 5% annual escalation factor for SPP energy market costs.

The data summarized in Table A depicts a better overall comparison of the comparable administrative costs that would actually be incurred by Aquila over the ten-year time horizon. MISO's costs are initially higher from 2008 through 2010 (33.8 cents per MWh in 2008 and decreasing to 32.1 cents per MWh in 2011) because their energy market already exists and they have incurred development and experience ongoing operating costs. Backing out the costs associated with the ASM project for the sake of comparison in overall market functionality and recognition of the total amortization of the deferrals associated with the

MISO existing energy market is appropriate. MISO's energy and transmission service administrative costs level off at 30.7 cents per MWh beginning in 2012.

Starting with MISO's administrative costs and reducing these costs by an unsupported 20% reduction assumption as stated in the CRA International Analysis is inappropriate. SPP's actual comparable administrative costs today are 46% higher (19 cents versus 13 cents per MWh) than MISO's costs for providing transmission service. This is consistent with the statement in my rebuttal testimony that they have 1/3 the load of MISO's to spread these fixed costs over. It is also unlikely that SPP could develop the energy markets at a cost per MWh market load that is 20% less than MISO's. Even if this hypothetical assumption was achievable, the SPP administrative costs beginning in 2011 are still 5 to 6 cents more than MISO's per MWh of market load. A more likely scenario depicts SPP's administrative rates at 10 to 11 cents per MWh of market load higher than MISO due to the fixed nature of these costs and overall increases in software and system development costs over the next three years.

TABLE A

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Net Energy GWh	8,823	9,074	9,322	9,570	9,570	9,570	9,570	9,570	9,570	9,570
	MISO Adm. Costs										
	CRA Original Rate	0.373	0.358	0.356	0.356	0.356	0.356	0.356	0.356	0.356	0.356
Less:	MISO ASM	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035
	Deferral Day 2	0	0	0	0	0.014	0.014	0.014	0.014	0.014	0.014
	MISO Adm. Rate	**0.338**	**0.323**	**0.321**	**0.321**	**0.307**	**0.307**	**0.307**	**0.307**	**0.307**	**0.307**
	SPP Adm. Rate										
	SPP 1A	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Plus:	RT/DA Mkt	0	0	0	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	SPP Adm. Rate (including 20% reduction)	**0.19**	**0.19**	**0.19**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**
	SPP Adm Rate (excluding 20% reduction)	**0.19**	**0.19**	**0.19**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**

C. The adjustments to the respective RTO Administrative Costs using the same net energy in MWh from the CRA International Analysis (see Table 18 in the CRA analysis) times the revised rates from Table A above are shown on Table B below.

These adjustments show that over the ten-year time interval, the net present value (NPV) of MISO's administrative costs compared to SPP's under the assumed 20% reduction is $1.3 million higher in MISO, but if the 20% reduction scenario is disregarded, SPP's costs exceed MISO's by $700,000.

As stated in my rebuttal testimony, the key factor in CRA's analysis of SPP benefits is the erroneous recognition of $45.8 million in net trade benefits from 2008 through 2010 that is based on SPP markets that do not exist.

As the administrative cost analysis goes out into future years (2011 - 2017), the difference in administrative costs favors MISO by $400,000 per year under the 20% reduction in development and operating costs theorized by SPP, and closer to $900,000 per year in those future years if the 20% reduction is not assumed to occur. However, under the NPV analysis these administrative costs have less of an impact in today's dollars.

TABLE B

RTO Administrative Costs

	Notes	NPV	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Original	(From CRA C/B Analysis)	23.5	35.8	3.3	3.3	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0
MISO	(adjusted for ASM/deferrals)	21.3	32.5	3.0	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7
SPP	(less 20% reduction)	20.0	32.1	1.7	1.7	1.8	3.5	3.6	3.7	3.8	3.9	4.0	4.1
	MISO NPV > SPP NPV	**1.3**											
SPP	(excluding 20% reduction)	22.0	35.4	1.7	1.7	1.8	4.0	4.1	4.2	4.3	4.4	4.5	4.6
	SPP NPV > MISO NPV	**0.7**											

ATTACHMENTS:

Exhibit 1 - MISO's 2008 Budget Review (page 9)
Exhibit 2 - SPP Cost Breakdown Required under Order No. 668

ANSWERED BY:

/s/ Mark Volpe

Signature

Finance Subcommittee Report

Midwest ISO
2008 Budget Review

Midwest ISO Personnel

Area	2007	2008	Change
IT	192	205	13
Real-Time Operations	144	158	14
Market Operations	87	93	6
Transmission Management	79	87	8
Market Planning	69	77	8
Ancillary	38	1	-37
Legal & External Relations	32	39	7
Business Services	26	29	3
Finance	26	26	0
Executive	21	21	0
Planning & Performance Mgt	17	19	2
Interregional Coordination	6	6	0
Internal Audit	3	3	0
	740	764	24

Budget does not fund all positions.

Ancillary Markets personnel moved from project to IT, RT Ops, etc.

SPP Southwest Power Pool

In accordance with Order 668, FERC now requires RTOs to provide a breakdown of the allocation of its operating costs into three specific accounts. SPP's cost allocation provided below is based on 2007 budget figures for billing periods beginning January 1, 2007.

561.4 Scheduling, System Control and Dispatching Services (43%)	8.07 cents per MWh
561.8 Reliability Planning and Standards Development Services (6%)	1.23 cents per MWh
575.7 Market Facilitation, Monitoring and Compliance Services (51%)	9.70 cents per MWh
	19.00 cents per MWh

Case No.: EO-2008-0046

Schedule RJJ-5

Excerpts from Staff Report - FERC Docket No. PL04-16-000

Staff Report on
Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization

Docket No. PL04-16-000

Prepared by the Staff of the
Federal Energy Regulatory Commission

October 2004

(A) Identification of the Minimum Functions Required for a Day One Regional Transmission Organization

Through several orders, the Commission has concluded that certain limited functions provide a suitable beginning that allows a proposed RTO to have a sufficient level of market independence and operational authority to qualify for RTO status.[4] The Commission's findings in these orders repeatedly focused on the notion of functional authority over the operations of the transmission grid, independent from market participants, with oversight responsibilities that are intended to remove any barriers to non-discriminatory practices and create robust competition.

Order No. 2000 specified eight functions for RTOs: tariff administration and design, congestion management, parallel path flow, ancillary services, OASIS, market monitoring, planning and expansion, and interregional coordination. The difference between the minimal requirements to operate an RTO and the more complex functions currently performed by, for example, Northeastern ISOs and RTOs is referred to as "Day One" versus "Day Two" RTO functionality.

Figure 1

	Pre-Day One	Day One	Day Two
Tariff Administration & Design		X	X
Congestion Management			
Redispatch		X	
Market-Based			X
Parallel Path Flow		X	X
Ancillary Services		X	X
OASIS	X	X	X
Market Monitoring		X	X
Transmission Planning		X	X
Interregional Coordination		X	X
Day-Ahead Energy Market			X
Same-Day Energy Market			X
Ancillary Services Market			X
Capacity Market			X

Figure 1 shows the minimum functions of a Day One RTO, as spelled out in Order No. 2000. To operate as an RTO, the Day One entity must meet the minimum requirements of Order No. 2000, but such operation may not include market-based mechanisms for congestion management or the operation of energy markets. A fully functional RTO (or Day Two RTO) will carry out all of the functions to a greater extent, employing market-based mechanisms, and include additional functions.[5] Staff notes that "Pre-Day One" organizations perform only regional OASIS functions, without actually controlling the transmission facilities. ERCOT, for example, initially operated in this manner.

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[4] *See, e.g.*, Arizona Public Service Company, *et al.*, 101 FERC ¶ 61,033 (2002); Avista Corp., *et al.*, 100 FERC ¶ 61,274 (2002); and Southwest Power Pool, Inc., 106 FERC ¶ 61,110 (February 10, 2004).

[5] It should be noted that functions such as operating ancillary services and capacity markets are optional programs that some existing RTOs, such ISO-NE, have chosen to perform.

While Order No. 2000 put forth eight minimum functions that an RTO must perform, some of these functions are unlikely to be fully performed by a Day One RTO. For example, market monitoring takes place on a smaller scale for Day One operations than under the Day Two scheme. Similarly, the Day One RTO will initially have a role in transmission planning, but only at the Day Two point will the RTO become fully responsible for planning. Finally, the extent of congestion management differs between Day One and Day Two entities. The Commission has ruled that full market-based congestion management does not have to be performed when RTO operations commence.[6] The variation in performing these functions has a direct effect on the resources devoted to them. This Study attempts to capture only those resources that have been classified as Day One functions. This Study does not consider the resources associated with retail access programs. State legislated retail access or retail choice programs are not a requirement of Order No. 2000. While these programs are created by the states, and implemented by the RTO, such programs are considered voluntary, under a Day One or a Day Two RTO.

In order to use information as provided by RTOs and ISOs, Staff organized the cost data into consistent functions. For this, Staff found it useful to rely on the North American Electric Reliability Council (NERC) functional model.[7] The advent of open-access transmission service and the evolution of competitive markets and new entrants prompted NERC to re-evaluate the functions performed by the traditional control area operator. NERC issued a schematic of functions that can be applied across regions and across different regulatory and institutional structures. This model defines the core functions of control area operators and assigns responsibility for maintaining reliability. It also explains the relationship between and among the entities responsible for performing the tasks within each function. FERC has encouraged the use of the NERC functional model in its RTO policy in order to clarify responsibilities between transmission owners and RTOs/ISOs.[8]

Staff determined the following NERC functions necessary to satisfy the Commission's requirements for becoming an operational RTO: Transmission Service Provider and Reliability Authority. In addition, a transmission support function and organizational management are necessary to develop an adequate framework for the Day One RTO. Finally, the Day One RTO should be responsible for the regional oversight of transmission planning. While not necessarily performing the planning function, oversight

[6] *See* Arizona Public Service Company, *supra* note 5; Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 (December 20, 2001).

[7] See Exhibit 2 for a graphic representation.

[8] *See* Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,145 (October 29, 2003) and Southwest Power Pool, Inc., 106 FERC ¶ 61,110 (February 10, 2004).

authority and the ability to review expansion is critical for regional reliability.

Transmission Service Provider

The Transmission Service Provider administers the transmission tariff and provides transmission services to qualified market participants. The tasks involved include receiving and processing transmission service requests; maintaining a commercial interface for receiving and confirming such requests (*i.e.*, an open access same-time information system or OASIS); approving or denying transmission service requests; approving interchange transactions; determining and posting available transmission capacity (ATC) values; and allocating transmission losses among the users. The analysis assumes that the RTO will facilitate provision of ancillary services so transmission customers will have a one-stop shop from which to obtain the necessary ancillary services from the underlying transmission and generation owners.[9]

The Transmission Service Provider will perform OASIS and tariff administration and design functions in accordance with Order No. 2000. Market monitoring also falls under the purview of the Transmission Service Provider.

Reliability Authority

The Reliability Authority, as defined in the NERC model, ensures the real-time operating reliability of the interconnected bulk electric transmission systems within a Reliability Authority Area.[10] Activities include, but are not limited to: (1) enforcement of operational reliability requirements; (2) monitoring of all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance; (3) revision authority for transmission and generation maintenance plans; (4) development and enforcement of interconnection reliability operating limits to protect against instability and cascading outages; (5) approval/denial authority over bilateral schedules from a reliability perspective; and (6) direction of emergency procedures and system restoration.

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[9] The NERC Reliability Function Model includes other responsibilities, including a Balancing Authority, which has the responsibility to maintain load-interchange-generation balance within its area of responsibility. Many of the authorities for this function are served through the provision of ancillary services under an Open Access Transmission Tariff (OATT).

[10] A Reliability Authority Area is the collection of generation, transmission and loads within the boundaries of the Reliability Authority. This boundary coincides with one or more Balancing Authority Areas, which are the areas in which a controlling Organization maintains a load-resource balance.

To perform these duties, the Transmission Service Provider needs to communicate with market participants, generators, transmission owners and operators and distribution owners. This communication often requires hardware and software interconnectivity to achieve the real-time monitoring and actions necessary to maintain the reliable operation of the grid. These systems are often embodied in energy management (EMS) and Supervisory Control and Data Acquisition (SCADA) systems.[11]

The RTO will perform other reliability-related Day One functions as described in Order No. 2000. These functions include congestion management, parallel path flow, ancillary services, transmission planning and interregional coordination.

Support Functions

While the NERC Model was used to determine the necessary operational functions of an RTO, Staff determined that additional cost centers were needed to capture the required administrative functions of a Day One RTO. Accordingly, two additional cost categories were included in the analysis—Transmission Support and Management.

<u>Transmission Support</u>

Transmission Support function, as Staff has defined it, includes the systems (hardware and software) and other necessary capital assets for the settlements and billing, and customer service operations. This list, while not exhaustive, best reflects the support services necessary in the provision of transmission service.

<u>Management</u>

The second support function is the day-to-day management of the transmission organization. The services included in this function include human resources, finance, administrative support, and building operations. Accordingly, the systems (*e.g.*, executive and decision support systems and general web service), furniture, and related assets were included in the Day One operations.

(B) Representative Study Group

After Staff determined the functions necessary for a Day One RTO, investment

[11] EMS systems, often characterized as the communication system with the generators and their operation, are typically embodied in a SCADA system, which, while collecting generator and transmission flow data, also can monitor and collect data on discrete facilities (breakers, lines, generator nodes, etc.) for purposes of monitoring the grid.

and expense profiles were developed. Staff reviewed the operations of existing ISOs and RTOs to determine a representative group for a Day One RTO. With the exception of the PJM Interconnection, LLC (PJM), Staff excluded ISOs and RTOs that developed from a tight power pool. As a result, the Midwest Independent Transmission System Operator (Midwest ISO), the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), and PJM were selected for study.[12] This review did not select the Northeast entities (ISO-New England and New York ISO) or the California Independent System Operator, Inc. (CAISO) as representative examples.[13] These entities, among other things, began operations with full Day Two market functions. As such, their costs were not representative of Day One RTO costs.

SPP is unique in this analysis, and the results for it should be interpreted accordingly. At the time of this Study, SPP had only been granted conditional RTO status.[14] The costs and expenses reflected in this Study are accurate for the services SPP currently provides, but are not necessarily reflective of a fully operational Day One RTO. For example, one of the functions of a Day One RTO is market monitoring, but funds for an independent market monitor are not included in SPP's budget. In contrast, SPP has been able to draw on the formation and operating experience of other RTOs, reducing the outlay required for start-up.

Information sources utilized in the Study include industry interviews, industry submissions, FERC Form No. 1 documents, and data from Commission audit staff. The ISO and RTO cost submissions were derived from actual and budgeted costs, and were developed in summary format in an effort to respond to the scope of this Study; they do not represent actual current revenue requirements. The information, in some instances, was purported to be illustrative of what each entity believed it would cost to replicate and administer its organization. Some actual data from a specific reporting period, indicated as representative of the Day One operations defined in this Study, was also submitted. Each entity denoted the specific time frame in its development that is representative of Day One RTO functions. For example, the Midwest ISO and ERCOT identified end-of-year 2002 numbers as the best representation of their Day One costs and expenses.

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[12] While it is recognized that the PJM area operated as an experienced power pool, the detailed data provided by PJM staff allowed for analysis, assignment and inclusion of PJM costs in the development of a Day One RTO.

[13] A cursory review of the data from the NYISO and ISO-NE indicated that, because they evolved out of tight power pools, were not representative of the Day One RTO development this Study attempts to capture. Review of the CAISO financial data indicated that it would not lend itself to identification of the Day One functionality with reasonable results.

[14] Southwest Power Pool, Inc., *supra,* note 8. *See also* Southwest Power Pool, Inc., 108 FERC ¶ 61,003 (July 2, 2004).

Case No.: EO-2008-0046

Schedule RJJ-6

Excerpts from Midwest ISO's Responses to Dogwood Energy, LLC Data Requests

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	))))))	Case No. EO-2008-0046

MIDWEST ISO'S RESPONSES TO DOGWOOD ENERGY, LLC DATA REQUESTS TO MISO

Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), provides the following responses to the Data Requests submitted to it by Dogwood Energy, LLC ("Dogwood") on or about December 18, 2007, all pursuant to 4 CSR 240-2.090:

The Midwest ISO incorporates, by reference the general objections to this series of Data Requests timely filed on December 28, 2007, and the following responses are being provided subject to, and without waiving any of those general objects, but they are being provided in the spirit of the cooperation in the Commission's discovery process.

Questions regarding testimony of MISO Witness Pfeifenberger

1. **Reference:** Exhibit JPP-1. Please identify any testimony Mr. Pfeifenberger has prepared on behalf of SPP members.

   Response: Mr. Pfeifenberger has not previously prepared testimony on behalf of SPP members.

2. **Reference:** Exhibit JPP-1. Please provide copies of all previous studies, reports, and analysis Mr. Pfeifenberger has prepared with regard to SPP operations and SPP tariffs.

   Response: Mr. Pfeifenberger has not previously prepared studies, reports and analysis with regard to SPP operations and SPP tariffs.

11. Please identify all market services currently provided by MISO that are not provided by SPP.

    Response: Mr. Pfeifenberger does not possess the detailed knowledge of SPP operations or information to be able to respond to this request. Further, Mr. Pfeifenberger has not analyzed all market services currently provided by the Midwest ISO and those that are or are not provided by SPP. However, Mr. Pfeifenberger does have a general understanding of services provided by the Midwest ISO and that are not currently provide by SPP, which include firm network service for all RTO-internal transactions, full market-based congestion management, financial transmission rights, integrated locational day-ahead and real-time energy markets, and virtual bidding. See also page 24 of Mr. Pfeifenberger's rebuttal testimony discussing the lack of an SPP Day-2 market design.

12. **Reference:** Page 5, lines 12-14. Please explain why the displacement of utility-owned generation by purchase of power may not even be feasible and indicate whether Mr. Pfeifenberger's statement is based on existing and/or projected transmission system constraints that would prevent such purchases? If so, please identify all such transmission system constraints, by transmission bus, in the GE-MAPPS models.

    Response: It is unclear what this particular Data Request is seeking and certain premises contained within the request relative to transmission constraints are unclear. The cited portion of the testimony is based on Mr. Pfeifenberger's experience and illustrates that: (1) this type of RTO cost-benefit analyses is unlikely to result in a finding that 15% to 25% of utility generation would be replaced with market purchases; and, (2) many utilities <u>may</u> not be able to displace 15% to 23% of utility-owned generation using market purchases. Mr. Pfeifenberger's referenced statement is founded on his experience with how much generation tends to be displaced due to simulated differences in RTO participation. It is not based on any specific existing and/or projected transmission constraints.

    a. Is Mr. Pfeifenberger or MSIO aware of actual uplift costs paid to generators within MISO during calendar year 2006 or in the first 11 months of 2007? If so, please provide a list of generators that received uplift payments, the hours when those generators were dispatched, and the uplift payments made.

       Response: The statement on page 5, lines 12-14 of Mr. Pfeifenberger's testimony relates to the Aquila Study's finding of Aquila generation that is estimated to be displaced in the "Aquila in SPP" scenario. This statement relates to the uplift costs as calculated by Aquila's consultants as the

Case No.: EO-2008-0046

Schedule RJJ-7

Excerpts from Southwest Power Pool's Responses to Dogwood Energy, LLC Data Requests

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	))))))	Case No. EO-2008-0046

DOGWOOD ENERGY, LLC'S FIRST DATA REQUESTS TO SOUTHWEST POWER POOL, INC.

Dogwood Energy, LLC ("Dogwood") hereby submits the following data requests pursuant to 4 CSR 240-2.090 to Southwest Power Pool, Inc. ("SPP"):

1. Please see Attachment 2 to Independence's response to Aquila Data Request No. ILA-002 IND, which is represented as being a cost allocation of SPP's 2007 budget (in accordance with FERC Order 668) that is posted on SPP's OASIS. Please confirm that the 9.70 cents per MWh listed for Account 575.7 includes all costs for 2007 that SPP believes at this time were applicable to the operation and development of SPP's EIS Market in 2007. Please provide the costs in cents per MWh that were applicable to SPP's EIS Market in 2007 if this cannot be confirmed and explain your answer. Please also list and describe in further detail the types of costs that SPP includes in Account 575.7 beyond the brief description provided in Attachment 2 to the referenced data response.

SPP RESPONSE: Annually, SPP allocates its administrative fee into three categories in accordance with FERC's Order 668 (i.e. Account 561.4 – Scheduling, System Control and Dispatching Services, Account 561.8 – Reliability Planning and Standards Development Services, and Account 575.7 – Market Facilitation, Monitoring and Compliance Services). SPP undertakes a process to identify its direct costs associated with the three accounts identified by FERC Order 668. These direct costs are then assigned to each account along with a pro rata share of SPP's indirect costs being recovered under Schedule 1A of the SPP Open Access Transmission Tariff. Account 575.7 contains the following direct costs: salaries and benefits, travel, meeting expenses, consulting, services, and depreciation and amortization specifically tied to SPP's provision of a real-time energy market and performance of market monitoring and compliance functions. Additionally, Account 575.7 contains an allocation of SPP's indirect costs on a pro rata basis determined by direct staffing. These indirect costs include, but are not limited to, expenditures for facilities, insurance, support staff, communications systems, legal, etc.

SPP believes Account 575.7 contains all operating costs applicable to operation of SPP's markets in 2007.

ATTACHMENT: None

ANSWERED BY: Tom Dunn

____
Signature

February 19, 2008
____
Date

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Schedule RJJ- 8

Revised Table A

Revised Table A

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Net Energy GWh	8823	9074	9322	9570	9570	9570	9570	9570	9570	9570
	MISO Adm. Costs										
	CRA Original Rate	0.373	0.358	0.356	0.356	0.356	0.356	0.356	0.356	0.356	0.356
Less:	MISO ASM	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035
	Deferral Day 2	0	0	0	0	0.014	0.014	0.014	0.014	0.014	0.014
	MISO Adm. Rate	**0.338**	**0.323**	**0.321**	**0.321**	**0.307**	**0.307**	**0.307**	**0.307**	**0.307**	**0.307**
	SPP Adm. Rate										
	SPP 1A (Non-Mkt)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093
Plus:	RT/DA Mkt	0.097	0.097	0.097	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	SPP Adm. Rate (including 20% reduction)	**0.190**	**0.190**	**0.190**	**0.273**	**0.273**	**0.273**	**0.273**	**0.273**	**0.273**	**0.273**
	SPP Adm. Rate (excluding 20% reduction)	**0.190**	**0.190**	**0.190**	**0.318**	**0.318**	**0.318**	**0.318**	**0.318**	**0.318**	**0.318**

Case No.: EO-2008-0046

Schedule RJJ- 9

Aquila Missouri Flowgate Analysis

Aquila Missouri Flowgate Analysis

Flowgate	Voltage*	Limit**	Reliability Coordinator	Major Contributors to Loading Powerflows	Major Contributors to Unloading Powerflows (Counterflows)
Iatan - Stranger Creek	345	1195	SPP	WR, KCPL, MPS, KACY	KCPL, MPS, AECI, NPPD, OPPD, LES
St. Joseph - Hawthorn	345	1138	SPP	KCPL, INDN, KACY, MPS, AECI	KCPL, MPS, AECI, NPPD, OPPD, LES
Iatan – St. Joseph	345	956	SPP	MPS, AECI, NPPD, OPPD, LES	KCPL, WR, WEPL
Overton - Sibley	345	956	MISO	MPS, KCPL, INDN, KACY, WR	AMRN, AECI, SWPA
Stilwell – Redel	161	335	SPP	MPS, INDN, KCPL, AECI	KCPL, WR
Duncan – Blue Springs East	161	324	SPP	KCPL, MPS	MPS, INDN, AECI
St. Joseph – Cook	161	315	SPP	MPS	AECI
Turner - Martin City	161	250	SPP	None	MPS
St. Joseph – Midway (1)	161	182	SPP	AECI	MPS
St. Joseph – Midway (2)	161	182	SPP	AECI	MPS
St. Joseph – Midway (3)	161	164	SPP	AECI	MPS
Maryville – Clarinda	161	168	MISO	OPPD	AECI, MPS

* Voltage of monitored element in kV
** Summer Emergency Limit

Analysis data was obtained from SPP list of flowgates and PowerWorld Simulator analysis of SPP powerflow case. Contributors are generally listed in descending order of flowgate power flow impacts (TDFs).

Contributor Naming Key

Utility Name	Acronym	RTO Market
Ameren	AMRN	MISO
Aquila Missouri	MPS	None
Associated Electric Coop	AECI	None
City of Independence	INDN	None
Kansas City BPU	KACY	SPP
Kansas City Power and Light	KCPL	SPP
Lincoln Electric System	LES	None
Nebraska Public Power District	NPPD	None
Omaha Public Power District	OPPD	None
Southwestern Power Admin.	SWPA	None
West Plains Power and Light	WEPL	SPP
Western Resources (Westar)	WR	SPP

Case No.: EO-2008-0046

Schedule RJJ-10

Midwest ISO's Responses to Dogwood Energy, LLC Data Requests

MIDWEST ISO RESPONSES TO DATA REQUESTS
Case: EO-2008-0046

Date of Response: 2/8/2008

Data Request Nos.	**Dogwood Energy Second Data Requests to Midwest ISO Nos. 43 - 48**
Requested By:	**Carl J. Lumley**
Description:	**See Data Requests and Responses below**

43. **In anticipation of the CRA analysis of the "Aquila in MISO" case, or for any other reason, did MISO prepare deliverability studies of any or all of Aquila's generating resources in Missouri?**

Response: No. The Midwest ISO has not yet studied the Aquila units and would do so once it is clear that Aquila is fully ready to join and joining the Midwest ISO. This process would take approximately two (2) weeks.

a. **If the answer is "yes," please provide the amount of capacity qualified as a MISO network resource for each individual Aquila generating unit, and the amount of capacity qualified as a local resource for each individual Aquila generating unit. Please provide all supporting documents and analysis for your answer.**

b. **Response**: N/A

c. **If the answer is "No," then for the purposes of the CRA "Aquila in MISO" study, did the analysis assume that all Aquila generating units were 100 percent deliverable into MISO? If the answer is "yes," please explain the basis for that assumption. Please provide all supporting documents and analysis for your answer.**

Response: This type of modeling (e.g., the GE-MAPS modeling effort undertaken by CRA for Aquila) assumes the output of generating units is "deliverable" subject to transmission constraints in the region. The Aquila Study's assumed capability of the transmission system to physically deliver the output of Aquila units is the same for the "Aquila in Midwest ISO" and "Aquila in SPP" cases. See Aquila Study, Sections 3.1 and 7.1.

d. **If the answer to (b) is "No," please list the specific network resource and local resource capacity values assumed for each and every Aquila generating unit, and the basis for those assumptions. Please provide all supporting documents and analysis for your answer.**

Response: See Aquila Study, Section 8.

44. **In anticipation of the CRA analysis of the "Aquila in MISO" case, or for any other reason, did MISO prepare any deliverability studies of the Dogwood (Aries) plant? If so, please provide the results of those studies.**

Response: See response to Data Request 43, above.

a. **If MISO did not prepare any such studies, please provide the network and local capacities assumed in the CRA analysis for the Dogwood (Aries) plant, and basis for those assumptions. Please provide all supporting documents and analysis for your answer.**

Response: See first response under Data Request 43.

b. **If the Dogwood (Aries) plant was assumed to be 100 percent deliverable into MISO in the CRA "Aquila in MISO" analysis, please explain the reason(s) for the estimated uplift costs for the plant in that analysis.**

Response: Whether or not a power plant is physically 100 percent deliverable within the type of market simulations undertaken by CRA is generally unrelated to whether the plant is estimated to incur uplift costs. The reasons for the unreasonable estimates of Dogwood uplift costs in the "Aquila Standalone" and "Aquila in Midwest ISO" cases of the original CRA simulations, the results of which were summarized in the Aquila Study, are explained in the rebuttal and supplemental rebuttal testimonies of Mr. Pfeifenberger. See also response to DR No. 45.

45. In general, would MISO participants incur uplift costs for resources whose capacity is determined to be 100 percent deliverable into MISO? If the answer is "yes," please explain all of the factors that can create uplift costs associated with those resources within the context of the GE-MAPS model analysis performed by CRA. Please include all relevant studies, documents, and data with your response.

Response: The term "uplift cost" is not a defined term in the Midwest ISO's tariff. However, the Midwest ISO's revenue sufficiency guarantee (RSG) charges are sometimes referred to as "uplift" costs. The incurrence of RSG costs is generally unrelated to whether or not a generating unit is deemed "100 percent deliverable" into the Midwest ISO market area. In the context of the type of market simulations undertaken by CRA for the Aquila Study, the term "uplift cost" generally refers to dispatch cycles during which the dispatch cost of a generating units exceeds the simulated market price at the plant's location. Uplift costs can be incurred in the context of the GE-MAPS model analysis performed by CRA if the GE-MAPS model commits a resource which then needs to be dispatched at costs that are above locational market prices. As explained in Mr. Pfeifenberger's rebuttal and supplemental rebuttal testimonies, erroneous uplift costs can be created by unreasonable modeling assumptions or unreasonable model algorithms.

46. In general, does MISO expect that, during times when security constrained economic dispatch of generating units occurs on the MISO system, would

MISO participants incur uplift costs from constrained units? Why or why not? Please provide all supporting documents and analysis for your answer.

Response: See response to Data Request 45, above.

47. **If Aquila does join MISO, can MISO guarantee that all of Aquila's existing generating units will be 100 percent deliverable into MISO for the next 10 years? For the next 20 years? Why or why not? Please provide all supporting documents and analysis for your answer.**

Response: It is readily apparent from the form of this question that it is primarily rhetorical in nature and that the requestor understands and expects that the Midwest ISO does not have the ability to affirmatively guarantee 100 percent deliverability over the stated time frames provided as there are many factors and/or issues outside of or beyond the control of the Midwest ISO. The Midwest ISO is bound by and must follow the criteria and processes described in its applicable Tariff provisions that are on file with and approved by the FERC.

a. **If the answer is "no," please state whether MISO can guarantee any percentage deliverability into MISO for any or all of Aquila's generating plants for the next 10 years, and for the next 20 years. Please provide all supporting documents and analysis for your answer.**

Response: Without waiving or contradicting the response provided above and in the spirit of cooperating in the discovery process the Midwest ISO provides the following additional response. An analysis has not been performed to evaluate the deliverability of Aquila's generating resources into MISO. All units can be 100% deliverable as long as the transmission is built to address the limiting constraints in out year planning (MTEP) case. In the event the study determines that units can not be 100% deliverable due to constraints, partial deliverability will be granted. However the undeliverable generation can be deemed as a local capacity resource and can continue to serve the load under existing contracts. This is all subject to and presumes full compliance with the appropriate tariff provisions and requirements.

48. **If Aquila does join MISO, can MISO guarantee that the Dogwood (Aries) generating plant will be 100 percent deliverable into MISO for the next 10 years? For the next 20 years? Why or why not?**

Response: See response to Data Request 47 above.

a. **If the answer is "no," please state whether MISO can guarantee any percentage deliverability into MISO for the Dogwood (Aries) generating plant for the next 10 years, and for the next 20 years. If so, please state the percentage(s) and provide all supporting documents and analysis for your answer.**

   Response: Without waiving or contradicting the response provided above and in the spirit of cooperating in the discovery process the Midwest ISO provides the following additional response. Deliverability can and must be provided under the Midwest ISO appropriate tariff provisions as long as the deliverability constraints caused by the Dogwood Plant are addressed. Otherwise the undeliverable portion of the plant could be a local capacity resource and can continue to serve the load under existing contract.

The individuals responsible for preparing and providing the Midwest ISO's responses to these requests were Midwest ISO Witness Johannes Pfeifenberger with The Brattle Group, and Eric Laverty, Sr. Manager of Transmission Access Planning, Midwest Independent Transmission System Operator, Inc.