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Issues:	Aquila's Application to Join Midwest ISO
Witness:	Michael S. Proctor
Sponsoring Party:	MoPSC Staff
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Case No.:	EO-2008-0046
Date Testimony Prepared:	November 30, 2007

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

Aquila Inc.
d/b/a Aquila Networks – MPS and Aquila Networks – L&P

CASE NO. EO-2008-0046

Jefferson City, Missouri
November 30, 2007

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the following Rebuttal Testimony in question and answer form, consisting of 45 pages of Rebuttal Testimony to be presented in the above case, that the answers in the following Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S Proctor
Michael S. Proctor

Subscribed and sworn to before me this 28th day of November, 2007.

NICHOLAS P. FOLIGNO
Notary Public, State of Texas
My Commission Expires
September 05, 2011

Notary Public

My commission expires 9/5/2011

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DIRECT TESTIMONY

OF

MICHAEL S. PROCTOR

AQUILA INC.

d/b/a Aquila Networks – MPS and Aquila Networks – L&P ("Aquila")

CASE NO. EO-2008-0046

DIRECT TESTIMONY

OF

MICHAEL S. PROCTOR

AQUILA INC.

d/b/a Aquila Networks – MPS and Aquila Networks – L&P ("Aquila")

CASE NO. EO-2008-0046

Q. What is your name and business address?

A. My name is Michael S. Proctor. My business address is 9900 Page Avenue, Suite 103, Overland, MO 63132.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission (Commission) as Chief Regulatory Economist in the Energy Department.

Q. What is your education background and work experience?

A. I have Bachelor and Master of Arts Degrees in Economics from the University of Missouri at Columbia, and a Ph.D. degree in Economics from Texas A&M University. Prior to coming to work for the Commission, I was an Assistant Professor of Economics at Purdue University and at the University of Missouri at Columbia. Since June 1, 1977, I have been on the Staff of the Commission and have presented testimony on various issues related to weather normalized energy usage and rate design for both electric and natural gas utilities. With respect to electric issues, I have worked in the areas of load forecasting, resource planning and transmission pricing. Currently, I am serving as chairman of the Southwest Power Pool Regional State Committee's Cost Allocation Working Group, chairman of the

Organization of Midwest ISO States' (OMS') Financial Transmission Rights Working Group and co-chairman of the OMS' Transmission Pricing Working Group.

Q. What are your current duties in the Energy Department as Chief Regulatory Economist?

A. I have the responsibility of being actively involved with the development and structure of Regional Transmission Organizations (RTOs) which have the purpose of increasing efficiency and reliability in the competitive supply of electricity at wholesale. In addition, I am also responsible to testify before the Commission on various issues where I have relevant expertise and experience.

EXECUTIVE SUMMARY OF REBUTTAL TESTIMONY

Q. On what issue are you filing rebuttal testimony in this proceeding?

A. My rebuttal testimony will address Aquila's application to join the Midwest Independent System Operator Inc. (MISO) as its RTO Transmission Provider.

Q. What areas of expertise or experience do you have for addressing Aquila's application?

A. Because of my involvement with RTOs, I am familiar with the design and operation of both the MISO and the Southwest Power Pool (SPP). In addition, I was the Staff's primary witness in three other applications by Missouri Investor-Owned Utilities to become members of RTOs: 1) AmerenUE's application to join MISO (EO-2003-0271); 2) Kansas City Power & Light's (KCPL's) application to join SPP (EO-2006-0142); and 3) Empire District Electric's (EDE's) application to join SPP (EO-2006-0141).

Q. What is the Staff recommendation concerning Aquila's application for Commission authorization to join MISO?

A. I recommend that the Missouri Public Service Commission deny Aquila's application.

Q. What is the basis for this recommendation?

A. The Staff evaluated the application under the standard of "not be detrimental to the public interest" as articulated by the Commission in its *Report and Order* in Case No. EF-2003-0465. In that case, when considering whether to authorize Aquila to pledge assets to secure term loans, the Commission stated, at pages 6-7 of its *Report and Order*, that "a detriment to the public interest includes a risk of harm to ratepayers" and that the Commission, in considering the risk of rate increases, followed an "analysis [that] conforms to the concept that . . . '(n)o one can lawfully do that which has a **tendency** to be injurious to the public welfare.'" (Citation omitted emphasis in original).

The physical location of Aquila's service area in Missouri is in and about the cities of Kansas City and St. Joseph. As shown in Schedule 1 attached to my rebuttal testimony, Aquila is electrically connected with seven other utilities, three of which are in SPP and one of which is in MISO. The two most logical choices of RTOs for Aquila to join are MISO and SPP. Thus, from the Staff's perspective, the crucial question in this case is whether the net benefits are greater if Aquila joins MISO or SPP, or neither.

Q. In this regard, how did you determine which RTO is most likely to provide greater net benefits?

A. CRA International (CRA) performed an independent cost-benefit study with stakeholder input that was funded by Aquila which indicates that while joining MISO would benefit Aquila's ratepayers, joining the SPP would likely provide significantly greater benefits to those same ratepayers. As an economist, I evaluate benefit and detriment based on opportunity cost. Thus, with a likely greater benefit from joining the SPP than MISO, approval for Aquila to join MISO would be a detriment to Aquila's ratepayers and therefore a detriment to the public interest.

Q. Is it your recommendation that the Commission authorize Aquila to join SPP?

A. No. Aquila has not requested Commission authorization to join SPP.

Q. What specific areas are addressed in your rebuttal testimony?

A. First, I address the roles of RTOs. This includes a description of the functions that are performed by RTOs, as well as their basic characteristics.

Second, because the Staff recommendation is based on the results of the CRA cost-benefit study, I address my understanding of the modeling concepts that were employed by CRA. In addition, I address the stakeholder process Aquila followed in having the cost-benefit study performed, as well as three major issues that were raised through the stakeholder process:

1) CRA modeled SPP as if it included the same market functionality as MISO. At present, MISO has a day-ahead energy market and a real-time energy market, while SPP has only a real-time energy market.
2) CRA modeled the former Aries (now Dogwood) plant as if it was a resource designated to serve Aquila's load. Aquila has not contracted to purchase this plant or energy and capacity from this plant.
3) MISO was concerned with the fact that the Dogwood plant produced significantly more energy in the MISO case than in the SPP case.

My rebuttal testimony addresses what I believe are reasonable answers for all three of these major issues.

Third, I have included a section on interconnections between MISO, SPP, Aquila and Associated Electrical Cooperatives Inc. (AECI). This information has two purposes: 1) it shows the lack of interconnections between MISO and Aquila compared to SPP and Aquila; and 2) it shows that both MISO and SPP are highly interconnected with AECI.

Fourth, because the primary link between MISO and SPP is AECI, not Aquila, I have added a section regarding seams agreements: agreements among transmission providers regarding the exchange of information, the coordination of day-to-day operations and the coordination of transmission planning. Because Missouri is divided among three primary transmission providers, MISO, SPP and AECI, it is critical that all three have seams agreements that coordinate information, day-to-day power flows and future development of the transmission infrastructure in Missouri.

Fifth, it is my understanding that MISO intends to perform additional cost-benefit analyses to address all three issues, and any final recommendation I would make to the Commission could potentially change after reviewing the results of MISO's analyses. If the yet to be revealed results of these new cost-benefit analyses provide convincing evidence to support that it would not be detrimental to the public interest for Aquila to join MISO, then the next section of my rebuttal testimony sets out conditions that the Commission should impose should it authorize Aquila to join MISO.

Sixth, in the final section, I briefly discuss the potential impact that the proposed merger between Aquila and KCPL could have on this case. There is a potential conflict only if the best RTO choice for Aquila is MISO.

<u>BACKGROUND: RTO FUNCTIONS AND BENEFITS</u>

Q. What is an RTO?

A. An RTO is an entity, approved by FERC, to provide wholesale transmission service on a regional basis. Wholesale transmission service basically serves two needs for transmission customers.

1) Long-Term Deliverability of Electricity from Designated Resources to Load: This involves the transmission service needed to deliver electricity from suppliers (generators) to utilities (load serving entities) that have designated generation resources from that supplier to serve their loads. These generation sources are called "Designated Resources." The transmission service for delivery of power from Designated Resources is typically thought of in terms of what is called network service, although transmission for the delivery of power from a Designated Resource to a load can be provided through what is called point-to-point service. For example, a municipal that has a wholesale contract with a supplier for capacity and energy from a plant or group of plants requires transmission service to deliver the electricity from the supplier's source to its load destination, and can arrange for transmission as either a network transmission service customer or a point-to-point transmission service customer.

2) Short-Term Deliverability of Electricity from Economy Transactions: This involves transmission service needed to deliver available surplus electricity from lower-cost resources as a substitute for electricity from higher-cost Designated Resources. Surplus energy can come from a Designated Resource not needed to serve the utility's own (native) load or can come from a merchant generator (one without any obligation to serve load). Examples of these types of economy wholesale transactions of power include time frames from month-to-month, week-to-week, day-to-day, hour-to-hour or even 5 minutes-to-5 minutes.

Q. What obligations does the RTO have regarding its role in providing these transmission services?

A. The RTO has an obligation to operate the regional transmission grid in a reliable manner. In addition, the RTO has an obligation to provide open access to the transmission system on a non-discriminatory basis. These obligations result in RTO tariffs approved by the Federal Energy Regulatory Commission (FERC) that describe in great detail how transmission service is provided.

Q. Regarding the transmission services related to long-term delivery of electricity from designated resources to load, what are the RTO's primary responsibilities?

A. The RTO is responsible for both transmission grid operations and coordinated regional planning. First, with respect to transmission grid operations, the grid cannot be separated between wholesale and retail transactions. Thus, utilities must submit their schedules (what resources they intend to use to meet their loads) to the RTO that include all generation to serve both wholesale and retail loads. One of the primary reasons for this requirement is that every kilowatt-hour from a generation source flows across every transmission facility in an interconnected network. Thus, the generation from one utility's power system impacts all of the other utilities' power systems. The industry calls these impacts on neighbors "loop flows." The concept of loop flow is that if an electrical path is thought of (or modeled) as going from specified generation sources to specified load destinations, that power goes beyond the boundaries of the utility's transmission system and loops back into that system in order to arrive at its load destination. The RTO must know all the generation being operated, both for wholesale and retail, in order to know the flows to expect on the transmission system, and to be able to operate that system in a reliable manner.

Second, the RTO has the responsibility to coordinate regional planning of the transmission system. Actually, the RTO's responsibilities go further than simply coordinating the activities of the transmission owners in the region. For example, if the utility wants to add a new generation resource to meet its native load (the load for which the utility has incurred an obligation to serve, which includes both retail and wholesale load), it must submit a request to the RTO for long-term transmission service. The RTO must then determine whether or not any upgrades need to be made to the transmission system in order to reliably deliver the power from that generator to the load. Again, loop flows onto neighboring transmission systems can play a major role in determining the need for transmission upgrades. In addition, as customer loads increase, this load growth may occur in areas other than originally forecasted and thereby put demands on the transmission system not originally expected. The RTO has the responsibility of reviewing the region's transmission grid to determine if additional transmission upgrades are needed because of these changes.

Q. Regarding the transmission services related to short-term delivery from economy transactions, what are the primary responsibilities of the RTO?

A. The RTO's responsibilities for short-term delivery from economy transactions are similar to those for long-term delivery of power from Designated Resource to load. First, since economy transactions involve substituting energy from lower-cost resources for energy from higher-cost Designated Resources, there can be significant changes in the power flows that occur when native load is not totally being served from the utilities' Designated Resources. These transactions can occur in two ways. First, utilities can enter into bilateral transactions – an agreement between a seller and a buyer. These bilateral transactions must be submitted to the RTO for approval; i.e., the RTO must determine that the transaction will not result in power flows that overload a portion of the transmission system. These bilateral transactions require a purchase of the use of the transmission system, and the RTO is responsible for billing the party that is requesting this type of short-term transmission service. A second way that these economy transactions can take place is through the RTO operating energy markets, where sellers submit offers for the sale of electricity. The RTO's responsibility with regards to energy markets is to determine the least-cost dispatch of generation that meets all of the power flow limits of the transmission system. This determination is made on an every five minute basis, with the RTO communicating electronically with each generator the level of megawatt-hours that it is expected to produce.

With respect to planning, the RTO also has the responsibility to perform economic studies of the transmission system that are intended to determine whether or not there are transmission upgrades that can reduce the overall costs of producing electricity within the region. The reduced production costs are then compared to the cost of the transmission upgrades to determine whether or not such transmission expansion provides net benefits to the region.

Q. What is the rational for using RTOs to operate regional energy markets?

A. When an RTO functions without operating an energy market, the mode of operation is to evaluate requests for economy transactions on a first-come, first-served basis. This type of energy market is restricted by the lack of what is called "price transparency," which means that less than full information regarding offers from suppliers is available to all of the market participants. Because of this, the most economical transactions will not necessarily occur, and there is a much higher likelihood that utilities having market power will exercise that power to the detriment of the region. In order to reduce production costs to the region and to increase the efficiency of the energy markets, RTOs have taken on the responsibilities of operating centrally dispatched energy markets.

Q. What are the required functions of an RTO?

A. The following are the required functions of an RTO:

1. The RTO is to be the sole administrator and provider of wholesale transmission service.
2. FERC Order 2000 contains certain requirements with regard to congestion management that is the responsibility of an RTO.

3. An RTO must have procedures in place to address parallel path flows (loop flows) within its region and other regions.
4. The RTO must be the provider of last resort for ancillary services.
5. An RTO must be the single administrator of it open access transmission tariff.
6. The RTO must engage in market monitoring.
7. The RTO is responsible for planning the expansion of the regional transmission system.
8. The RTO is responsible for interregional coordination.

While I previously discussed several of the primary RTO functions, there are other important functions that I will discuss in what follows.

Q. What is meant by congestion management?

A. Congestion management is the process by which the RTO determines how the power grid will operate when requests for transmission service violate the reliability limits set for the transmission system. Assuming that the RTO has not over-scheduled or over-dispatched the system, violations can occur when loop flows from neighboring transmission systems occur at unexpected high levels.

In an RTO without an energy market, congestion management is done through a process of what is called Transmission Loading Relief (TLR). This is a method of decreasing power flows on overloaded transmission elements by curtailing transmission service, usually on a pro rata basis from the loadings of each transmission customer on the overloaded element. This curtailment of transmission service typically results in the utilities having to redispatch higher cost generation to meet their loads. Without having any information on the levels of higher costs that result from these curtailments of transmission service, TLRs can be an inefficient way for an RTO to relieve congestion.

In an RTO with an energy market, congestion management is done through a redispatch of the generation that is least cost in meeting the reliability limits set for the transmission system. A centrally operated energy market provides a more efficient method for congestion management in two ways: 1) by having offers from generators, the redispatch is based on economics; and 2) without the centrally operated energy market, a concern about overselling transmission service can cause the RTO to be more conservative in terms of transactions that it will allow.

Q. What are ancillary services for transmission of electricity?

A. In general, ancillary services are generation services that are necessary for the reliable provision of transmission service. There are three primary ancillary services.

The first ancillary service is voltage support that is determined by the amount of reactive power put into the grid. Each generating unit produces real power (megawatts) and reactive power (megavars). Reactive power is necessary to maintain the correct voltage levels on the power system, but cannot be transmitted over long distances. Thus, generation of reactive power from relatively nearby power plants may need to be adjusted to provide correct voltages to a local area.

The second ancillary service is regulation that is involved in the balancing of actual power flows with what is called the net interchange schedule. The net interchange schedule determines the net of imports and exports scheduled into and out of a balancing area. The transmission lines that tie together balancing areas (called "tie lines") are monitored by each balancing area's dispatch authority. The balancing area authority's objective is for the actual net interchange from the monitored power flows to equal the scheduled net interchange on a second-to-second basis. In order to do this, the balancing area authority has specified units on automatic generation control. If the monitored levels of net interchange show too much power is being exported out of the balancing area, then the units with automatic generation control will decrease their output to restore balance. If the monitored levels of net interchange show there is too little power being exported from the balancing area, then the units with automatic generation control will increase their output to restore balance.

The third ancillary service is operating reserves that involve generators that are on standby to run when generation falls behind load in an area of the grid. For example, this can occur when an on-line generation unit is forced out of service. A portion of operating reserves must come from generation that is already operating – these are called spinning reserves, and a portion of operating reserves can come from generation that is not operating, but can be in operation within a very short period of time (e.g., ten minutes) –these are called quick start reserves.

Q. In what way is the RTO responsible for ensuring the provision of these ancillary services as the provider of last resort?

A. Just as in the case of transmission, the RTO does not own generation resources. Thus, the RTO is responsible to arrange with the generators in the region to provide these ancillary services. This includes the pricing of these services, which can occur either on a cost basis, where the costs are included in the RTO tariff, or in some cases on a market basis, where the RTO is responsible for the operation of the markets.

Q. What ancillary services are provided through an RTO operated market?

A. Within MISO and SPP, currently none of the ancillary services are provided through RTO operated markets. MISO has filed an ancillary service market design with the FERC to operate markets for regulation and operating reserves. SPP is in the process of evaluating various market designs and will have cost-benefit studies performed to determine whether or not offering regulation and operating reserves in an RTO operated market is cost effective. Neither MISO nor SPP offer markets for reactive power. One of the issues with reactive power is that it cannot be transmitted over long distances and that results in the lack of sufficient competition for the development of a healthy market.

Q. What is market monitoring?

A. Market monitoring is a process by which an entity called the market monitor has access to what would otherwise be confidential information, and uses this information to determine whether or not a market participant is exercising some form of market power. Essentially, the exercise of market power occurs when a market participant is able to manipulate the price of the product to its advantage. For example, the market monitors for MISO and SPP have up-to-date cost information on every generator involved in their respective markets. By comparing offers to cost information, the market monitor can determine through various tests whether or not a generator is attempting to manipulate market price. If this occurs, the market monitor will report this occurrence to the FERC, who in turn will order an investigation. In some instances, the market monitor can determine before hand that the potential for the exercise of market power is so great that mitigation of that market power must be in place in order to prevent the possible exercise of market power.

Q. Is the RTO, itself, responsible for market monitoring?

A. This varies with RTOs, but in the case of both MISO and SPP, they have independent market monitors, who, while funded by the RTO, are directly responsible to the FERC, not the RTO. In essence, the market monitor is a separate entity (not an employee of the RTO) with whom the RTO contracted under FERC approval, and which cannot be dismissed by the RTO without FERC approval. One of the reasons for independence of the market monitor is that a part of its job is to review the tariffs and actions of the RTO to determine whether any market participant has been given an unfair advantage over other market participants, whether intentionally or inadvertently.

Q. What is the purpose for interregional coordination?

A. Interregional coordination is required because whatever action an RTO takes, it will impact its neighbors, and whatever actions its neighbors take will impact the RTO. Interregional coordination formally occurs through what are called seams agreements. These are agreements in which the parties agree to exchange specified information and to coordinate both the operations and expansion planning of their transmission systems. I will discuss seams agreement in Missouri in a subsequent section of this testimony.

Q. What are the characteristics of an RTO?

A. According to FERC Order 2000, the four RTO characteristics are the following:

1. **Independence** – the first characteristic for an RTO is independence; i.e., the RTO must be independent of any market participant. Both MISO and SPP are governed by an independent Board of Directors. In addition, RTO employees and directors cannot have financial interest in any market participant. Both MISO and SPP are not-for-profit organizations and have no financial interest in any market participant. Both MISO's and SPP's decision-making processes are independent of control by any market participant or class of participants. MISO and SPP possess the right to file rates, terms and conditions related to its Tariff with the FERC as directed by the Board of Directors, while transmission owners retain their full rights to seek recovery of their specific wholesale transmission revenue requirements from FERC under provisions of the Federal Power Act.

2. **Scope and Configuration** – While the scope and configuration are quite different for MISO and SPP, the FERC has approved the scope and configuration for both MISO and SPP as RTOs.
3. **Operational Authority** – FERC Order No. 2000 requires RTOs to have functional authority over the operations for all transmission facilities under its control. Each RTO must provide FERC a list clearly identifying facilities under its functional control, and made clear in its Membership Agreement the RTO's authority to exercise operational control.
4. **Short-term Reliability** – FERC Order No. 2000 also requires that an RTO must have exclusive authority for: (1) receiving, confirming and implementing all interchange schedules; (2) ordering redispatch, if necessary for the reliable operation of these facilities, of any generator connected to transmission facilities it exercises functional control; (3) approving or disapproving all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) reporting to the FERC, since reliability standards are established by another entity, its ability to provide reliable, non-discriminatory and efficiently-priced transmission service.

<u>BASICS OF RTO COST-BENEFIT ANALYSIS</u>

Q. In the context of this case, where Aquila is seeking Commission authorization to join MISO, what do you mean by the term "RTO cost-benefit analysis"?

A. For purposes of this case, an RTO cost-benefit analysis is an estimate of the benefits and costs that the utility can expect if it were to join an established RTO.

Q. Who performed the cost-benefit study submitted by Aquila in this proceeding?

A. The cost-benefit study was performed by CRA, and was attached as Schedule 3 to the direct testimony of Aquila witness Mr. Dennis Odell.

Q. Would you briefly describe your understanding of the modeling concept employed by CRA to calculate what it calls trading benefits?

A. Yes. The modeling concept employed by CRA is similar to what is used in almost all of the cost-benefit studies for RTO participation that I have reviewed. The key component to the analysis is to determine which of the scenarios analyzed results in the greatest savings to adjusted production costs for the utility. Adjusted production costs are defined as the fuel and variable O&M costs associated with operating the utility's plants plus the cost of purchases of energy from the market minus the revenues from sales of energy to the market. This is the same definition that the Staff uses in rate cases to determine production costs for a given test period.

The calculation of adjusted production costs will vary depending on the scenario assumed for the utility; i.e., Aquila in MISO, Aquila in SPP or Aquila Stand-Alone scenarios. The benefits for RTO participation are then calculated as the differences in adjusted production costs from being in an RTO (MISO or SPP) compared to Aquila Stand Alone. There are two primary reasons that adjusted productions costs vary by scenario: 1) <u>financial</u>: hurdle rates assumed to do transactions outside of the RTO or control area in the Stand-Alone case; and 2) <u>physical</u>: congestion that prevents favorable transactions from taking place.

Q. What are hurdle rates?

A. As a part of the cost-benefit analysis CRA uses computer software to model the power grid with an optimization routine that chooses the least-cost generation unit output that meets the load demand and the limits required for reliable operation of the transmission system. While this represents what would happen with a centrally dispatched market (e.g., an RTO operated energy market), it does not represent what happens in market systems that are not centrally dispatched (e.g., a market that depends on bilateral arrangements for the purchase and sale of electricity). In this context, hurdle rates are financial parameters designed and calibrated to reflect the operation of generation units within the context of inefficiencies that occur in a market system that is not centrally dispatched.

Q. What hurdle rates did CRA include in its RTO cost-benefit analysis for Aquila?

A. CRA included two types of hurdle rates: 1) unit commitment hurdle rates and 2) unit dispatch hurdle rates.

Q. What are unit commitment hurdle rates?

A. The purpose of a unit commitment hurdle rate is to capture the inefficiencies that exist when a utility has to make decisions a day ahead about which units to commit to operate the next day without having access to a day-ahead market. Offers into the day-ahead market allow utilities to specify their minimum-load and start-up offers (based on unit specific costs) as well as their offers to supply energy (based on unit specific marginal variable costs). Given offers from all utilities in the market, the RTO determines which units will be committed to meet load for the next day based on the lowest combined costs (start-up, minimum-load and variable), In essence, if a unit is not economic when considering all costs (minimum-load, start-up and variable costs) in comparison to other units, then it is not committed.

Q. What are minimum-load and start-up costs?

A. Minimum-load costs are the costs incurred by the generating unit when it is operating at its minimum level of economic output. This level of output is usually designated as the units "economic minimum," which is at a higher level than its physical minimum level, and is typically the level of output at which marginal or average variable cost start to increase with increasing levels of output. At lower levels of output than the economic minimum, the unit's marginal or average variable cost of operating the unit would decrease with an increase in output, resulting in lowering the overall cost of producing electricity. Operating a unit in this range is not economic.

The minimum-load costs are one of the costs associated with having a large base-load unit running during the low loads that occur during the night-time hours. The reason that these large base-load units run at low load times is that if they are shut down it takes several hours to start them back up, including additional costs, called start-up costs. Thus, one has to compare the costs incurred either from leaving a large base-load unit running over night or starting up such a unit to be available to produce electricity the next day to operating units, such as natural gas-fired peaking units, that have much quicker start-up times and lower start-up costs but much higher marginal variable costs. This is the primary function of an RTO run day-ahead energy market.

Q. If the RTO does not have a day-ahead energy market, how do utilities make decisions about which units to commit for the next-day operations?

A. Utilities have two options: 1) they can commit their own units based on their forecast of the next day's load; or 2) they can enter into bilateral agreements with other utilities for lower-cost electricity to meet their load on a day-ahead basis. In essence, without a day-ahead market, the only way to achieve the savings from unit commitment is through bilateral arrangements. While bilateral arrangements can allow you to not commit less efficient generation, those entering into this arrangement have to estimate whether their arrangement is the most economic without necessarily having full information of these costs with respect to the entire market. Thus, a day-ahead market incorporates full information for the entire market compared to only partial information associated with bilateral arrangements. This inefficiency in a non-centrally dispatched (bilateral) market is reflected in the CRA model through applying unit commitment hurdle rates to all generation not in the RTO to which Aquila is assigned, or to all non-Aquila generation in the Stand-Alone scenario.

Q. In a cost-benefit analysis, how does the inclusion of unit commitment hurdle rates impact the calculation of adjusted production costs?

A. The impact of unit commitment hurdle rates occurs at the margin. For example, in the Aquila Stand-Alone scenario, Aquila has to commit sufficient capacity to meet its load, and it would like to do this in the least-costly manner possible. Suppose a generation unit not in Aquilia's fleet of units for commitment can meet some of Aquila's next day load at a lower cost than a unit that Aquila would otherwise commit. Suppose that the savings from this change in unit commitment is $2/MWh for every megawatt-hour purchased by Aquila. However, if a $2/MWh unit commitment hurdle rate is placed on every transaction, then this $2/MWh savings is eliminated and this marginal trade would not take place. Thus, the inclusion of a unit commitment hurdle rate will eliminate all trades with savings that fall within the dollar per MWh gap set by that rate.

Q. What are unit dispatch hurdle rates and how do they impact adjusted production costs?

A. Unit dispatch hurdle rates represent the cost on a per megawatt-hour basis for entering into a transaction (either buying or selling energy) outside of the RTO or outside Aquila's control area in the Stand-Alone case. In essence, these reflect the cost of exporting or importing energy for Aquila under the various scenarios. When Aquila is modeled as a Stand-Alone utility (not in MISO or SPP), all transactions outside of the Aquila control area are subject to a unit dispatch hurdle rate. If an outside supply is available at $18/MWh and Aquila's decremental cost (cost saved by decreasing its own generation) is $20/MWh, then without a unit dispatch hurdle rate Aquila could achieve a net savings of $2/MWh on a transaction that substitutes outside energy for Aquila's own generation. However, if in this same case the unit dispatch hurdle rate is $2/MWh, there is no gain from the transaction because the savings is eliminated by the unit dispatch hurdle rate. Thus, trading benefits from being in an RTO versus being on a Stand-Alone basis measure the incremental savings in trades that occur within the RTO absent the unit dispatch hurdle rates; i.e., one of the benefits from joining an RTO is that utilities do not have to pay transactional rates on transactions that occur within that RTO.

In this cost-benefit study, the unit dispatch hurdle rates used by CRA were the tariffed point-to-point transmission rates for: 1) Aquila on a Stand-Alone basis, and 2) SPP and MISO for transactions into and out of their respective RTO regions. (See for example CRA Study: *RTO Cost – Benefit Analysis Aquila Missouri Electric Utility Operation*, at pages 10 and 32)

Q. Were there any other model assumptions made to reflect the benefits from being in an RTO?

A. Yes. In addition to the benefits from eliminating hurdle rates, CRA included benefits from more accurate management of congestion in the RTO scenarios by increasing the flowgate ratings from 90% in the stand alone scenario to 100% in both RTO scenarios. The 90% rating of flowgate capacity in the stand alone scenario was used to reflect the inefficiencies found in the TLR method for managing congestion used by utilities that are not in RTOs as discussed earlier in my rebuttal testimony.

Q. What do you mean by physical congestion on the transmission system?

A. Physical congestion occurs when the thermal capacity of the transmission lines or the rated capacities of the various flowgates would be exceeded by the dispatch of the lowest cost generation resources within the model. A flowgate is a group of lines that can move power from one point in the power grid to another point, where the power flowing from one point to the other flows simultaneously over all of the lines in this group. The flowgate rating is typically based on what is called an N-1 contingency condition. This means that the power across the flowgate cannot exceed the capacity of the group of lines under the assumption that the line with the greatest capacity is out of service. These types of N-1 constraints are required by national reliability conditions in order to ensure the security of the power grid.

Q. How does congestion impact the calculation of adjusted production costs?

A. Congestion will increase adjusted production costs due to the fact that the use of lower cost generation is restricted by the limits on flows across the congested portion of the transmission system. Consider two cases where in one case the utility being considered is more highly interconnected in one RTO than in another. Then, in order for the transactions in the RTO with fewer interconnections to the utility to match those of the other RTO, these fewer interconnections must have an equivalent megawatt transfer capability, otherwise they will become congested resulting in a decrease in the megawatt quantity of trades for the utility in that RTO, and this leads to lower savings in adjusted production costs. In brief, the less highly interconnected a utility is to an RTO, the greater will be the likelihood that lower trading benefits will result from being in that RTO. In a subsequent section of this testimony, I will go into greater detail about the interconnections between Aquila and MISO compared to Aquila and SPP.

<u>PROCESS REGARDING THE AQUILA COST-BENEFIT ANALYSIS</u>

Q. Who were involved in the development and review of the results of the CRA cost-benefit study?

A. Along with Aquila, Commission Staff, the Office of Public Council, MISO and SPP were involved in several ways. First, in August of 2006, I expressed my concerns to Mr. Odell about using either the existing SPP or MISO cost-benefits studies as the basis for its filing an application to join MISO. In particular, the SPP study that was used for both the KCPL's and EDE's applications would not be appropriate for Aquila, as Aquila was not included in that study as a member of the SPP. While MISO had earlier performed a cost-benefit study on Aquila, I had raised several concerns about the outputs from that study with MISO, and to my knowledge those concerns were not addressed. For example, one of the outputs of the earlier MISO cost-benefit study was that Aquila would be subject to negative congestion costs on an annual basis were it to join MISO. This result did not make any sense to me, as it would indicate that Aquila's generation is strategically located in such a way that it should buy its power from the MISO market and sell all of its generation into the MISO market. In addition, I was concerned with the independence of having the RTOs that are being evaluated performing the cost-benefit studies. Because these existing cost-benefit analyses were not appropriate to Aquila, I recommended that Aquila hire an independent (from SPP and MISO) contractor to perform a cost-benefit analysis. Aquila issued an RFP and ultimately hired CRA to perform the cost-benefit study.

Second, I attended a meeting by telephone at Aquila's offices in Kansas City, Missouri. in mid-November, 2006. The Staff, the Office of Public Counsel, MISO and SPP were invited to discuss how CRA planned to perform the study and to provide feedback on CRA's plans.

Third, Aquila set up a second stakeholder meeting that was held May 31, 2007, at Aquila's offices in Kansas City. Prior to that meeting I sent out several questions regarding the results of CRA's cost-benefit study that I asked to be addressed at that meeting. In response to questions raised at this meeting, Aquila asked CRA to perform some additional analysis that was sent out to all the stakeholders on June 26. 2007. This analysis was in response to questions raised at the meeting regarding Aquila's interconnect capacity, new resources assumed in the analysis, and explanation for why Aries is committed more often in the MISO case than the SPP case.

In summary, the process through which Aquila had the CRA cost-benefit analysis performed was an open process that allowed inputs from various interested stakeholders. At the time, I was satisfied that CRA had made a good faith effort at developing unbiased studies of three scenarios for Aquila: 1) Aquila in MISO; 2) Aquila in SPP; and 3) Aquila as a Stand-Alone transmission provider.

Q. What were the final results of the CRA cost-benefit study?

A. The results showed present value net benefits over a ten-year time horizon (2008-2017) of $21.1 Million (M) for Aquila joining MISO and of $86.9 M for Aquila joining SPP. This is over a 4 to 1 ratio of net benefits for Aquila in SPP versus Aquila in MISO. Another way to compare these results is to consider a $21.2 M overestimate of trading benefits to Aquila for both cases. The result would be that joining MISO is no longer net beneficial, while joining SPP would still have net benefits of $65.7 M. In summary, there would have to be a significant modeling error in the SPP model resulting in an over estimate of benefits or a significant modeling error in the MISO model resulting in an under estimate of benefits to support Aquila's request to join MISO. This would only occur if there was somehow a SPP bias in the CRA's modeling of the two scenarios.

Q. Were you concerned that CRA may have included a SPP bias in its modeling of the two RTO scenarios?

A. Yes, this was a concern on two accounts. First, CRA modeled SPP as if it included the same market functionality as MISO. At present, MISO has a day-ahead energy market and a real-time energy market, while SPP has only a real-time energy market. In addition, MISO and SPP have different systems for financial transmission rights. Finally, MISO has filed at the Federal Energy Regulatory Commission (FERC) to implement Ancillary Service markets for regulation, and operating reserves to begin sometime in 2008. SPP is in the process of evaluating the costs and benefits of having a day-ahead market, having a more transparent market for trading financial transmission rights, and having Ancillary Service markets for regulation and operating reserves.

Second, CRA modeled the former Aries (now Dogwood) plant as if it was a resource designated to serve Aquila's load. At this time Aquila has not contracted to purchase this plant or energy and capacity from this plant.

Q. Do you believe it was appropriate for CRA to model SPP as if it included the same market functionality as MISO?

A. I was satisfied that the way CRA had treated this issue was acceptable. In order to compensate for the fact that there were differences in market functionality, CRA included the MISO costs associated with the additional market functionality in the estimate of SPP administrative costs. In fact, CRA included identical RTO administrative costs for both the MISO and SPP study scenarios. I believe that this is an appropriate way in which to balance the inclusion of market functionality that SPP does not currently have, but intends to include if such markets prove to be cost beneficial.

Q. Why do you believe that including identical RTO administrative costs balance the differences in market functionality between MISO and SPP?

A. First, in the long-run SPP will implement these same or similar markets if their implementation proves to be cost beneficial. Thus, including both the benefits and the costs associated with these markets in this study may underestimate the long-term net benefits from the SPP markets, and this would only happen if SPP determined that the benefits from adding any of these markets is outweighed by the cost of implementation that are similar to MISO's implementation costs.

Since CRA included both the total benefits and the total costs, if the incremental cost of implementing any given market is greater than the incremental benefit, then CRA will have underestimated total net benefits to Aquila for the SPP scenario. For example, suppose there are two markets being considered (e.g., the day-ahead market and the ancillary services market) with benefits of $10 million each. Also suppose the cost of implementing one of these markets is $5 M, but $11 M for the other market. In total, benefits are $20 M and costs are $16 M, resulting in net benefits of $4 M. However, when each market is evaluated on an individual basis, one market is not implemented because costs exceeded benefits, leaving benefits of $10 M and costs of $5 M, resulting in higher net benefits of $5 M. Thus, SPP's approach to implementing each market structure only when benefits exceed costs should result in long-term benefits to Aquila that are at least as high as those found by CRA in its study.

Q. Should the Commission be concerned about the time gap that it will take for SPP to perform its cost-benefit studies and then to implement those markets that prove to be cost beneficial?

A. Of course, the Commission should always be concerned about the timing of specific studies and implementation of markets that prove to be cost beneficial. But from the perspective of which RTO should Aquila join, I believe it is appropriate for the Commission to make its decision based on a longer-term view, knowing where each RTO intends to go with its development and implementation of new markets.

Q. What is the concern with CRA treating the Dogwood plant as a Designated Resource for Aquila?

A. First, the term Designated Resource means that the generation plant or unit under question is owned by or under contract to the load-serving entity, which in this case is Aquila. Instead, the Dogwood plant is owned by Dogwood Energy, LLC, who is currently without a long-term contract for sale of the power from its facility and is acting as a merchant provider of electricity. Thus, the characterization of the Dogwood plant as a Designated Resource for Aquila is incorrect.

Q. From the perspective of modeling costs and benefits from being in MISO versus being in SPP, does the incorrect designation of the Dogwood plant as a Designated Resource for Aquila impact the results?

A. Yes, it might have an impact on the results. The reason for this is that in the structure of the cost-benefit study, if a resource is not a Designated Resource of the utility and both the utility and that resource are not in an RTO (e.g., the Aquila Stand-Alone scenario), then a unit commitment rate should be included for that resource. In the CRA study, this unit commitment rate was not added for the Dogwood plant in the Aquila Stand-Alone scenario. Thus, in the Aquila Stand-Alone scenario, CRA likely underestimated the production costs for Aquila.

On the other hand, if Aquila is in an RTO and it is assumed the Dogwood plant is in that same RTO, a unit commitment rate should not be added, even though the Dogwood plant is not a Designated Resource for Aquila. Thus, in both the MISO and SPP cases, CRA did not underestimate the production costs for Aquila. This implies that the benefits shown for both the MISO and SPP cases are lower than they would be with the Dogwood plant as a merchant provider of electricity.

Q. Why would you apply the unit commitment hurdle rate for the Dogwood plant in the Aquila Stand-Alone scenario but not in either the MISO or SPP scenarios?

A. In the Stand-Alone scenario, Aquila would not have access to a market for making a day-ahead unit commitment, but in the MISO and SPP scenarios, they would. I realize that while the SPP does not currently have a day-ahead market it could be argued that a unit commitment hurdle rate should be applied to the Dogwood plant for Aquila in the SPP scenario. However, I have addressed this issue earlier in my testimony regarding the SPP's proposed cost-benefit analysis required to implement a day-ahead market.

Q. You have discussed applying the unit commitment hurdle rate to the Dogwood plant in the Aquila Stand-Alone scenario. Do you have similar concerns about applying the unit dispatch hurdle rate for transmission charges?

A. No, I do not. Since the Dogwood plant is located within the Aquila control area, if it were a Designated Resource for Aquila, transmission would be included as a part of the Aquila network rate. Thus, Aquila would not pay any more for transmission in either the MISO or SPP scenarios for delivery of power from the Dogwood plant. However, because Dogwood is not a Designated Resource, Aquila would purchase power from the Dogwood plant either as a MISO market resource in the MISO scenario or as an SPP market resource in the SPP scenario. In either scenario, there would still be no additional transmission costs associated with this purchase of energy. However, in the Aquila Stand-Alone scenario, Aquila would be required to charge itself its own transmission charge for purchases of energy from the Dogwood plant. However, because Aquila is paying itself, the net transmission charge would be zero. Thus, not including a unit dispatch hurdle rate for transmission charges in the Aquila Stand-Alone scenario is the correct modeling of the Dogwood plant.

Q. Were there any other concerns raised by stakeholders regarding the CRA modeling results?

A. Yes, there were. MISO was concerned with the fact that the Dogwood plant produced significantly more energy in the MISO scenario than in the SPP scenario.

Q. What was the explanation for this result?

A. The reason that the Dogwood plant ran more in the MISO scenario is primarily because of congestion from MISO into Aquila. I believe that this congestion is due to the lack of interconnections between MISO and Aquila.

INTERCONNECTIONS BETWEEN AQUILA, MISO, SPP AND AECI

Q. What level of interconnections exists between Aquila and neighboring transmission systems?

A. In response to data requests from Aquila (Staff DR #1), SPP (Staff DR #4) MISO (Staff DR #5) the number of tie lines and their MVA ratings are shown on Schedule 2. The interconnections to Aquila and tie line ratings are also summarized in the following table.

Table 1: Tie Lines into Aquila

Interconnection	Number of Lines	Summed MVA Capacities
SPP	14	5,915
AECI	10	2,385
MISO	2	1,207
Others	2	1,326

Data Sources: Aquila Supplemental Response to Staff DR 1

Q. What do Schedule 2 and Table 1 indicate regarding interconnections with Aquila?

A. Clearly, Aquila is more highly interconnected with SPP to the south and west than with any other entity. The next highest number of interconnections for Aquila is with AECI to the east. Aquila is least highly connected with MISO to the east and Nebraska (Nebraska Public Power District) and Iowa (Mid-America Energy Company) to the north.

Q. What is meant by "Summed MVA Capacities?"

A. Each line has a volt-amp (VA) capacity rating. MVA stands for millions of volt-amps. Volt-amps represent the voltage times the amperage of the lines, and we usually think of volt-amps as watts (watts = volts * amps). However, on line ratings, MVA is used rather than MW because the capacity ratings of a line do not determine the megawatts that can be transferred from one entity to another. This is primarily because of loop flows that naturally occur on an interconnected power system and flow over the tie lines, thereby reducing the megawatts of power that can contractually be transferred from one entity to another. In order to determine the total megawatt transfer capability between two control areas, special power flow studies have to be performed that take into account these loop flows. In addition, these power flow studies must also take into account contingency conditions that limit flows across various flowgates (combinations of lines that transfer power from one point in the power grid to another). Initially, in my data requests to Aquila, SPP and MISO I asked for total transfer capabilities between the various systems, but none of the three entities perform the calculation of total transfer capability in the provision of transmission service, and all three would have to perform additional and time consuming studies to make these calculations.

Q. Do sums of MVA capacities that don't take into account N-1 flowgate contingencies provide relevant information regarding strength of interconnections?

A. Generally, summing the MVA capacities of the tie lines gives a fairly good indication of interconnections on a relative basis. For example, Aquila has seven times as many tie lines with SPP than with MISO (SPP 14 vs. MISO 2), and has almost five times the summed MVA tie line capacities (SPP 5,915 MVA vs. MISO 1,207 MVA). Thus, it is highly likely that the megawatt import capability from SPP into Aquila is much higher than from MISO into Aquila, although I cannot say with certainty that it would be five times higher. However, these comparisons are a strong indication of the reason that Aquila in MISO resulted in significantly lower levels of energy purchases and a much higher level of energy production from the Dogwood plant when compared to the Aquila in SPP.

Q. Are there ways besides existing direct interconnections between MISO and Aquila to import electricity from MISO into Aquila?

A. Yes. As Schedule 2 indicates, MISO has over 60 tie lines with AECI. In addition AECI is connected to Aquila by ten tie lines. Moreover, AECI is critical to east to west power flows between MISO and Aquila.

Q. What would be required to expand power flows from MISO to Aquila?

A. If the power flows from MISO to Aquila were scheduled through AECI, what would be required is the purchase of firm transmission capacity on the AECI transmission system. At this time, no such purchase of firm transmission capacity is in place, and such firm transmission capacity may not be available without major transmission system upgrades.

Alternatively, if AmerenUE or an Independent Transmission Company is able to get approval for right-of-way, either could possibly build more interconnections to expand import capability into Aquila. There may be other alternatives that would require transmission service through other systems, but on the surface, these appear to be less likely alternatives.

Q. How would the purchase of firm transmission capacity on the AECI transmission system be reflected in the cost-benefit analysis?

A. The cost-benefit analysis includes what is called a dispatch hurdle rate between Aquila and AECI. This hurdle rate actually reflects the cost of transmission on a per megawatt-hour basis. If MISO or Aquila were to purchase firm transmission on AECI's transmission system, this hurdle rate would be removed for megawatts per hour up to the level included in the firm transmission service agreement. The partial removal of this hurdle rate would increase power flows between Aquila and AECI, allowing increased import capability from MISO into Aquila. In the cost-benefit study, the production cost savings from increased import capability would need to be netted with the increased costs being paid for transmission service through AECI and/or the cost of transmission upgrades required to achieve a higher level of import capability.

Q. Was this scenario of expanded import capability into Aquila from MISO considered in the CRA cost-benefit study?

A. No, it was not. Typically, these types of cost-benefit studies do not evaluate transmission upgrades or additional requests for transmission service. Specifically, if the cost-benefit study shows that costs exceed benefits, then it is not necessary to expand the study to evaluate transmission upgrades.

Q. If information regarding the costs and benefits of expanding import capability from MISO into Aquila were made available, should such information be taken into account?

A. Yes. Such information would give a longer-term perspective on costs and benefits for Aquila joining MISO, and would be consistent with the Staff's long-term perspective regarding the availability of various market structures within SPP.

<u>SEAMS AGREEMENTS WITHIN MISSOURI</u>

Q. Do either MISO or SPP currently have seams agreements with one another?

A. Yes, they do. MISO and SPP have entered into a Joint Operating Agreement that includes both the exchange of information and the coordination of power flows. This Joint Operating Agreement is very detailed and includes:

Article I	Recitals
Article II	Abbreviations, Acronyms and Definitions
Article III	Overview of Coordination and Information Exchange
Article IV	Exchange of Information and Data
Article V	ATC/AFC Calculations
Article VI	Reciprocal Coordination of Flowgates
Article VII	Coordination of Outages
Article VIII	Joint Operation of Emergency Procedures
Article IX	Coordinated Regional Transmission Expansion Planning
Article X	Joint Checkout Procedures
Article XI	Voltage Control and Reactive Power Coordination
Article XII	Additional Coordination Provisions
Article XIII	Effective Date (December 1, 2004)
Article XIV	Cooperation and Dispute Resolution Procedures
Article XV	Relationship of the Parties
Article XVI	Accounting and Allocation of Costs of Joint Operations
Article XVII	Retained Rights of Parties
Article XVIII	Additional Provisions

In addition, each RTO has included in its tariffs, documentation of its coordinated Congestion Management Process, which contains detailed descriptions of how loop flows from market operations in each RTO will be managed, including the reciprocal operation of coordinated flowgates.

Q. Do either MISO or SPP currently have seams agreements with AECI?

A. Yes, SPP has a transmission coordination agreement with AECI that it entered into on August 19, 2004. While this is a less lengthy document than the MISO-SPP Joint Operating Agreement, it addresses many of the same issues, including:

Transmission Data Exchange / Coordination
Participation in Regional Working Groups
Consideration of External Limitations
Use of Operating Guides
Coordinated Planning
Coordinated Scheduling

For example, both SPP and AECI agreed in making calculations of Available Flowgate Capacity (AFC) or Available Transmission Capacity (ATC) to take into account loop flows on the other party's system having response factors of five percent (5%) or greater.

A response factor measures the percent of the flow from a transmission service reservation that impacts the various transmission facilities. These impacts are calculated for loop flows that occur when the transmission reservation was not made on the other party's transmission system. For transmission service on the path between SPP and AECI, the parties agreed to work together to develop jointly agreed upon values for AFC/ATC postings. In addition, SPP and AECI agreed to coordinate schedules, both on a day-ahead and real-time basis. The purpose of schedule coordination is to prevent any loop flows from overloading transmission facilities in the other party's transmission system. If there is a scheduling conflict, the parties agree to work together to modify the schedule as soon as practical.

Q. Does MISO have any seams agreements, or their equivalent, with AECI?

A. Written agreements regarding data exchange or power flow operations do not directly exist between MISO and AECI. However, MISO does have a seams agreement with the Tennessee Valley Authority (TVA), and TVA is the Reliability Coordinator for AECI. Thus, coordination of congestion management does take place on a regional basis that includes AECI. Recall that congestion management for AECI is the use of TLRs to cut schedules for transmission service in order to prevent loading the transmission system in an unreliable manner. This arrangement appears to be adequate given the current configuration of MISO.

Q. In your opinion, is MISO's current seams agreement with TVA adequate for transmission through AECI, if Aquila were to join MISO?

A. No. Before the Commission even considers approving Aquila joining MISO, it is imperative that a direct seams agreement between MISO and AECI that includes Reciprocal Coordination of Flowgates be in place. This is particularly crucial because of the small number of direct interconnections between MISO and Aquila and the large number of parallel path flows from MISO to Aquila through AECI. As a member of MISO, Aquila's generation would be included in MISO's central market dispatch. If MISO is dispatching energy from the rest of its system into Aquila, the electricity from that dispatch will flow through the AECI transmission system. The picture the Commission should have in mind is power leaving AmerenUE's system flowing through AECI's system and into Aquila's system. These are what are called parallel path power flows. Without some form of written agreement involving limits on the use of AECI's transmission system by MISO, MISO's dispatch could overload the AECI system, and this could occur in the opposite direction when Aquila is selling power from its generation into MISO. Thus, without a Reciprocal Flowgate Coordination Agreement, Aquila joining MISO will make it increasingly difficult to manage congestion, and managing congestion in AECI through a TLR process could have detrimental impacts on the potential production cost savings that Aquila will actually receive as a member of MISO.

Q. What is a Reciprocal Flowgate Agreement?

A. This is a part of the Joint Operating Agreement in which the parties determine limits on flows they are allowed on one another's flowgates. These flowgates are sets of transmission facilities that have either a history or an expectation of flows that are near to the maximum flows allowed under N-1 contingency conditions. It is my understanding that in the Joint Operating Agreement with TVA, AECI was expected to come to agreement with MISO on Reciprocal Flowgates, but this agreement never materialized. MISO's position is that they do not have the authority to force an agreement with AECI, and so such an agreement was never reached.

POTENTIAL IMPACTS OF MISO COST-BENEFIT STUDY RESULTS

Q. What is your understanding of actions that MISO may take because of the concerns raised in the stakeholder review process?

A. In correspondence and conversations with the MISO Staff regarding this filing, I was informed that it had hired a consultant to present rebuttal testimony in which revisions will be made to the CRA cost-benefit study performed for Aquila. I am unsure as to when these additional runs will be completed, but I am expecting that they will be filed at the same time as this rebuttal testimony.

Q. Is it possible that the results of these additional cost-benefit runs could change your recommendation in this proceeding?

A. Without exact details of what changes will be made for these additional cost-benefit runs I cannot rule out the possibility that the results could change my recommendation. In any event, were MISO to ultimately file such cost-benefit runs as rebuttal testimony, I will respond to those runs and their implications for this case in my cross-surrebuttal testimony.

CONDITIONS FOR COMMISSION APPROVAL FOR AQUILA JOINING MISO

Q. Does the rest of your rebuttal testimony address Staff concerns about the relationship between Aquila and MISO, assuming that the Commission were to authorize Aquila to join MISO?

A. Yes, it does.

Q. If the Commission authorizes Aquila to join MISO, what conditions do you know now that you would recommend the Commission impose on such authorization?

A. If the Commission were to authorize Aquila to join MISO, I would recommend at least the conditions similar to those agreed to in the Stipulation and Agreements for Cases No. EO-2004-0141 and EO-0142 be imposed as preconditions to exercise that authorization.

Q. If the Commission were to decide to conditionally approve Aquila joining MISO, what process would you recommend be followed regarding these conditions?

A. In its order for conditional approval, the Commission should include a list of conditions that must be met for approval, and then require the parties to this case to develop a Stipulation and Agreement that sets out the details regarding how those conditions are to be met. I would recommend a two-month period be allowed for the parties to work out the details of that document.

Q. Regarding any such Stipulation and Agreement among the parties in this case, what conditions should the Commission require be addressed by the parties?

A. The conditions that should be addressed in a Stipulation and Agreement for this case include:

1) Interim approval by the Commission for the Aquila joining MISO for a period of seven (7) years;
2) An agreement by Aquila to perform a follow-up cost-benefit study to be submitted in an Interim Report as evidence regarding continuing RTO participation prior to the end of the interim approval period;
3) A cap placed on MISO administrative costs over the interim period, that if exceeded, triggers a filing by the utility with the Commission;
4) Full consideration being given to Aquila joining MISO on the same basis as other MAPP utilities that are not now members of MISO, without Aquila incurring any MISO exit fees;
5) A service agreement between Aquila and MISO that prevents the transfer of transmission rate setting for existing facilities from the Commission to the FERC, with the Commission's approval contingent on FERC approval of this service agreement;
6) Seams agreements involving all Missouri utilities, but specifically between MISO and AECI; and

7) Provisions related to Aquila withdrawal from MISO for fundamental changes in the utilities participation in MISO, including:
   a) Twelve months to effectuate a withdrawal from MISO;
   b) Recognition of exit fees related to withdrawal from MISO; and
   c) Aquila agrees to seek the Commission's approval to withdraw from MISO or take other actions that fundamentally change Aquila's participation in MISO; e.g., participation in MISO through an Independent Transmission Company.

Q. Why is the Staff recommending only an interim approval for Aquila joining an RTO with a follow-up cost-benefit study of actual benefits and costs?

A. The results of the CRA cost-benefit study provides a strong indication that net benefits to Missouri ratepayers from Aquila joining an RTO are positive. Cost-benefit studies are meant to be indicators of whether or not the dollar benefits of a particular decision are likely to exceed the costs, and as such should be interpreted as estimates, not as precise measurements. Many assumptions about future events and energy prices must be made in order to perform such studies, and to the extent that any of these assumptions are not fulfilled, the results of the study could be misleading. A major contributor to any potential difference in results is the relative cost of fuels, as well as the federal government's future policy with respect to carbon dioxide (e.g., CO_2 tax or CO_2 Cap and Trade). RTO energy markets allow greater substitution of lower cost generation (typically coal) for higher cost generation (typically natural gas). While the expected results for higher natural gas costs are likely to be greater benefits from RTO participation, if carbon dioxide legislation significantly increases the cost of coal-based electricity, these greater benefits may in large part be offset. While it is impossible to predict when the U.S. Congress will pass legislation on carbon dioxide, seven years provides a likely window, and also gives Aquila and the MISO sufficient time to work through whatever problems may occur in maturing new markets, such as the ancillary service markets.

Performing a follow-up cost-benefit study that measures actual benefits and costs associated with the RTO provides accountability for Aquila as well as for MISO. The Staff believes that this accountability is a key component for prudent management for both Aquila and the RTO. The Staff contemplates that the follow-up cost-benefit study will compare actual (modeled) production and ancillary service costs for Aquila as a participant in MISO markets compared to an estimate of what these costs would have been absent such participation. In this respect, the Staff expects Aquila will monitor its production and ancillary service costs on an ongoing basis, as well as make the types of comparisons that are required in the follow-up cost-benefit study to be submitted to the Commission in its Interim Report.

Q. If the Commission authorizes Aquila to join MISO, why is the Staff asking for Aquila to file an update to its continued participation in MISO if its costs exceed a specific cost cap?

A. The results of CRA's cost-benefit study are based on assumptions regarding MISO's costs. If MISO's costs go up significantly (e.g., greater than a 25% increase), then Aquila should file a pleading with the Commission to address the merits of their continued participation in MISO. While the Staff would leave the exact percentage increase that would trigger such a filing up to a negotiated settlement of the parties, there are two factors the parties should take into account: 1) accountability by MISO to meet its budgeted costs; and 2) the level of MISO costs that are likely to make Aquila's MISO costs exceed the benefits of being in the RTO.

Q. Why is the Staff requiring the parties to give full consideration to Aquila's participation in MISO on the same basis as MAPP utilities not currently in MISO?

A. MISO is currently proposing to allow utilities in the MAPP region to join MISO and participate in its markets without being subject to the system of MISO cost allocations for transmission upgrades. MISO has approved FERC tariffs regarding the allocation of costs for transmission system upgrades. Because of the weak interconnections with MISO, the Staff is very concerned about the fairness of this cost allocation and the resulting benefits that would flow to Aquila from these FERC approved cost allocations. Moreover, Aquila would be a boundary member of MISO, and benefits to Aquila will be highly restricted because of the lack of interconnections with the other parts of MISO. Given Aquila's weak interconnections to MISO, if it joins MISO, similar to the non-MISO members in MAPP, it should not be subject to allocation of costs for transmission upgrades from which it is highly unlikely to receive any benefits. Moreover, as indicated previously in my rebuttal testimony, AECI is a major barrier to market-based benefits flowing from MISO to Aquila, and it does not appear likely that this situation will change in the near future.

Q. Why would you exclude any exit fees for Aquila joining MISO on the same basis as MAPP utilities not currently in MISO?

A. While Aquila entered into an agreement to apply with this Commission to join MISO as a full member, it is not yet a member of MISO. If the Commission conditions Aquila joining MISO to be on the same basis as non-MISO MAPP utilities, then Aquila will have fulfilled its obligation to request to join MISO as a full member, and should not be subject to exit fees.

Q. What is the importance of the FERC approved Service Agreement between Aquila and MISO?

A. A critical issue to the Commission should be its jurisdiction over the rates paid by Missouri bundled retail ratepayers for transmission service from jurisdictional generation assets. The recognition of the jurisdiction of state commissions relating to ratemaking authority was initially set out in the FERC's White Paper (Wholesale Power Market Platform, April 28, 2003). The FERC stated that it will recognize states' ratemaking authority via a contract (Service Agreement) between the RTO and the utility.

Previously filed Service Agreements with FERC involving Missouri utilities specifically allowed the utilities to take network service from the RTO but does not require them to directly pay the RTO for service to its bundled retail load at the network service rate that is set in the RTO's tariff. This type of service agreement was entered into between: AmerenUE and MISO (Case No. EO-2003-0271); between EDE and SPP (Case No. EO-2006-0141); and between KCPL and SPP (Case No. EO-2006-0142). In each of these instances, the FERC subsequently approved these Service Agreements. As a part of the document of how the parties will meet the Commission's conditions, a similar Service Agreement between Aquila and MISO should be included, and both Aquila and MISO should agree that a condition precedent to Aquila's participation in MISO is the acceptance of the Service Agreement by the FERC.

Q. What are the rate terms and conditions that should be included in this Service Agreement?

A. The Service Agreement is meant to ensure that the Missouri Commission continues to set the transmission component of Aquila's rates to serve their Missouri bundled retail load. In effect, the Service Agreement prevents the transfer of transmission rate setting for Aquila to the FERC determined MISO rates. In particular the Service Agreement should include an Article which states that Aquila "shall not pay the rate set forth in Schedule 9 of the MISO OATT for using its own facilities to serve their Missouri bundled retail load." Schedule 9 is the MISO rate for network service for each of the various transmission zones from existing transmission facilities. How Aquila would be impacted by cost allocations for transmission upgrades would be considered by the parties regarding Aquila's participation in MISO in the same way as non-MISO members of MAPP.

In addition, to the extent that Aquila self-provides certain ancillary services related to regulation and operating reserves, they should not be required to pay MISO for these services on a MISO tariffed cost-based rate. This does not mean that with the start up of the ancillary services market that Aquila should necessarily be exempt from participation in this market. However, the parties should discuss potential problems with Aquila's participation in the MISO ancillary services markets due to the lack of interconnections between Aquila and MISO. Specifically, MISO should address the frequency with which it is likely for Aquila to become an isolated sub-region for the purpose of regulation or operating reserves, and the impact this might have for Aquila's participation in MISO's ancillary service markets.

Finally, as a network service customer of MISO, FERC does require that Aquila be subject to all non-rate terms and conditions under the MISO tariff applicable to Network Integration Transmission Service.

Q. Should the Stipulation and Agreement of the parties anticipate what would happen if FERC does not approve the Service Agreement between Aquila and MISO?

A. Yes. If changes are required by FERC, and Aquila and MISO can come to agreement regarding such changes, then a revised Service Agreement should be provided to the Commission and the signatories to the Stipulation and Agreement. Thereafter, within 90 days, any signatory to the Stipulation and Agreement can file with the Commission its position and recommendations regarding the nature of such revisions, including whether or not the Commission should rescind its approval or maintain its approval, with or without additional conditions.

Q. Why are seams agreements between MISO and AECI crucial to the approval of Aquila joining the MISO?

A. The primary purpose of a seams agreement is to ensure the reliable operation of the transmission system in Missouri. As indicated earlier in my rebuttal testimony, the seams agreement should set out the limits for MISO's use of AECI's transmission system, as well as AECI's use of the MISO operated transmission system. With the addition of Aquila to MISO, it needs to have similar agreements in place with AECI.

Q. Why are provisions for Aquila's potential withdrawal from MISO crucial to the approval of Aquila joining the MISO?

A. There are several conditions that should be addressed with respect to Aquila's potential withdrawal from MISO. First, if the Commission were to, at some future date, rescind its approval of Aquila's participation in MISO, it will take time for Aquila to fully effectuate such a withdrawal. In previous RTO agreements by AmerenUE, EDE and KCPL, this period was estimated at twelve months. If an order rescinding its approval by the Commission were to come later than twelve months before the expiration date of the Interim Period, the Interim Period should be automatically extended to allow for twelve months for Aquila to withdraw from MISO.

Second, the parties should recognize that Aquila leaving MISO would require it to pay an applicable exit fee. The Staff believes that if Aquila's exit from MISO is caused by escalating RTO costs at MISO, MISO should wave the exit fee to Aquila.

Third, should Aquila somehow want to fundamentally change the way that it participates in an RTO, either by requesting to join another RTO or by participation in MISO through an Independent Transmission Company, then it should come to the Commission for approval for any such actions.

Q. If the parties cannot come to a settlement on all conditions for Aquila joining MISO, what procedure do you suggest?

A. The Commission should have the parties present their positions on areas of disagreement and make a determination as to which position should be adopted as a condition for Aquila joining MISO.

POTENTIAL IMPACT OF A MERGER BETWEEN AQUILA AND KCPL

Q. What is the potential impact on this case of the Commission authorizing the proposed merger of Aquila and KCPL?

A. A potential conflict arises when authorization for the merger between Aquila and KCPL as well as for Aquila to join MISO are taken together. This occurs because KCPL is a member of the SPP, and if the merged entity desires to jointly operate the generation systems of KCPL and Aquila, then having one operating company in SPP and another in MISO may result in a conflict.

Q. Is there a process through which the Commission can effectively address this potential conflict?

A. Yes, I believe there is. First, if the Commission believes that Aquila joining MISO is not in the public interest, the Commission could issue that decision prior to any decision regarding the merger between Aquila and KCPL. However, if the Commission is seriously considering authorizing Aquila to join MISO, I would recommend that the Commission first take additional testimony on the impact that the merger has on this case. For example, if the merged entity continues to operate Aquila's generation independent from the generation of KCPL, then the cost-benefit studies submitted in this case remain valid. However, if the merged entity decides to jointly operate Aquila's and KCPL's generation, then the assumptions regarding hurdle rates used to characterize Aquila in MISO may no longer be appropriate, and additional cost-benefit runs may need to be made to correctly evaluate Aquila in MISO.

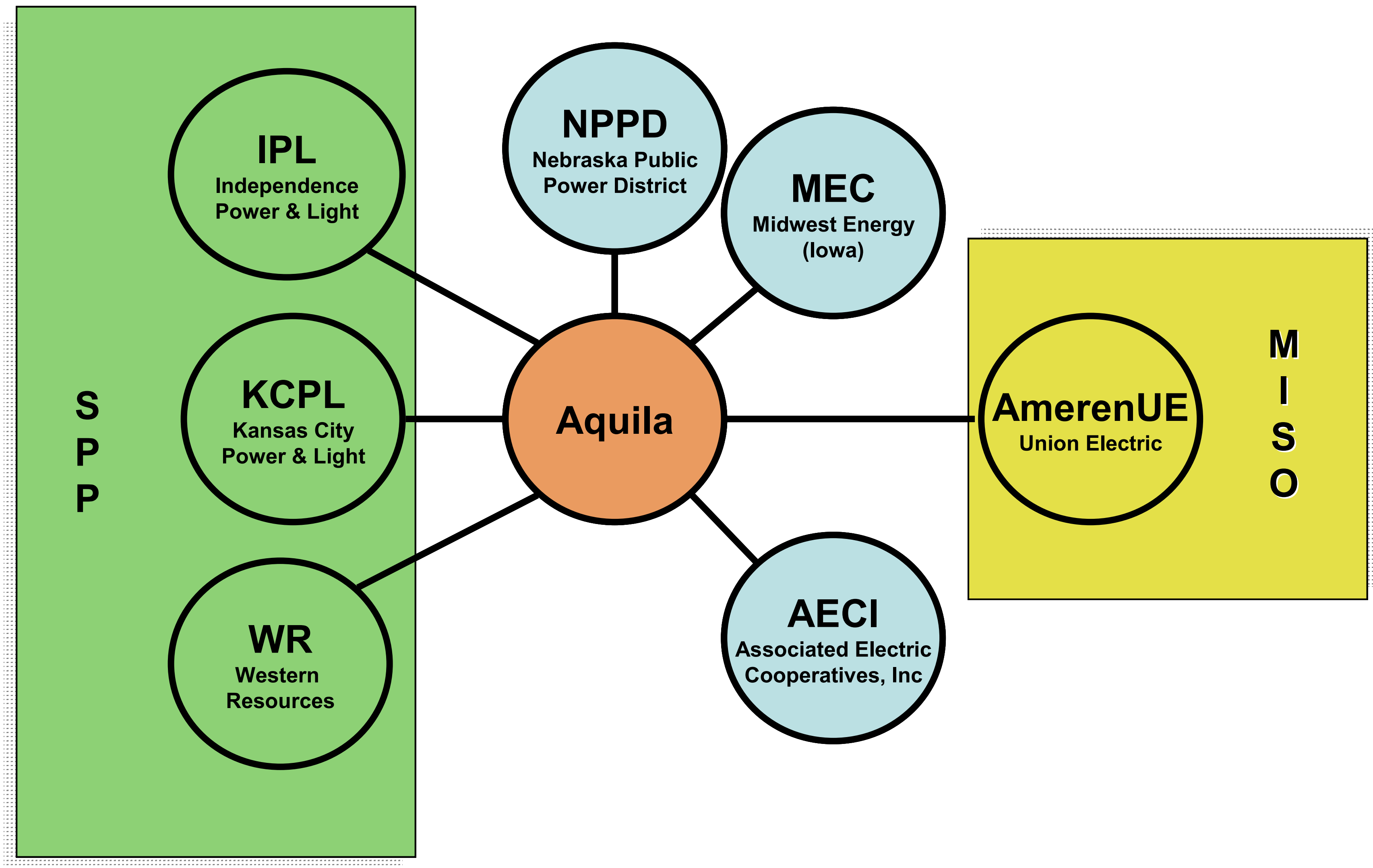
Q. Why didn't Staff request additional cost-benefit runs with Aquila and KCPL as a merged entity?

A. Because the CRA cost-benefit results did not indicate that MISO was the best RTO choice for Aquila, I did not consider the merger to be an issue for this filing. Thus, requesting additional cost-benefit runs involving the merged entity appeared to be unnecessary.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

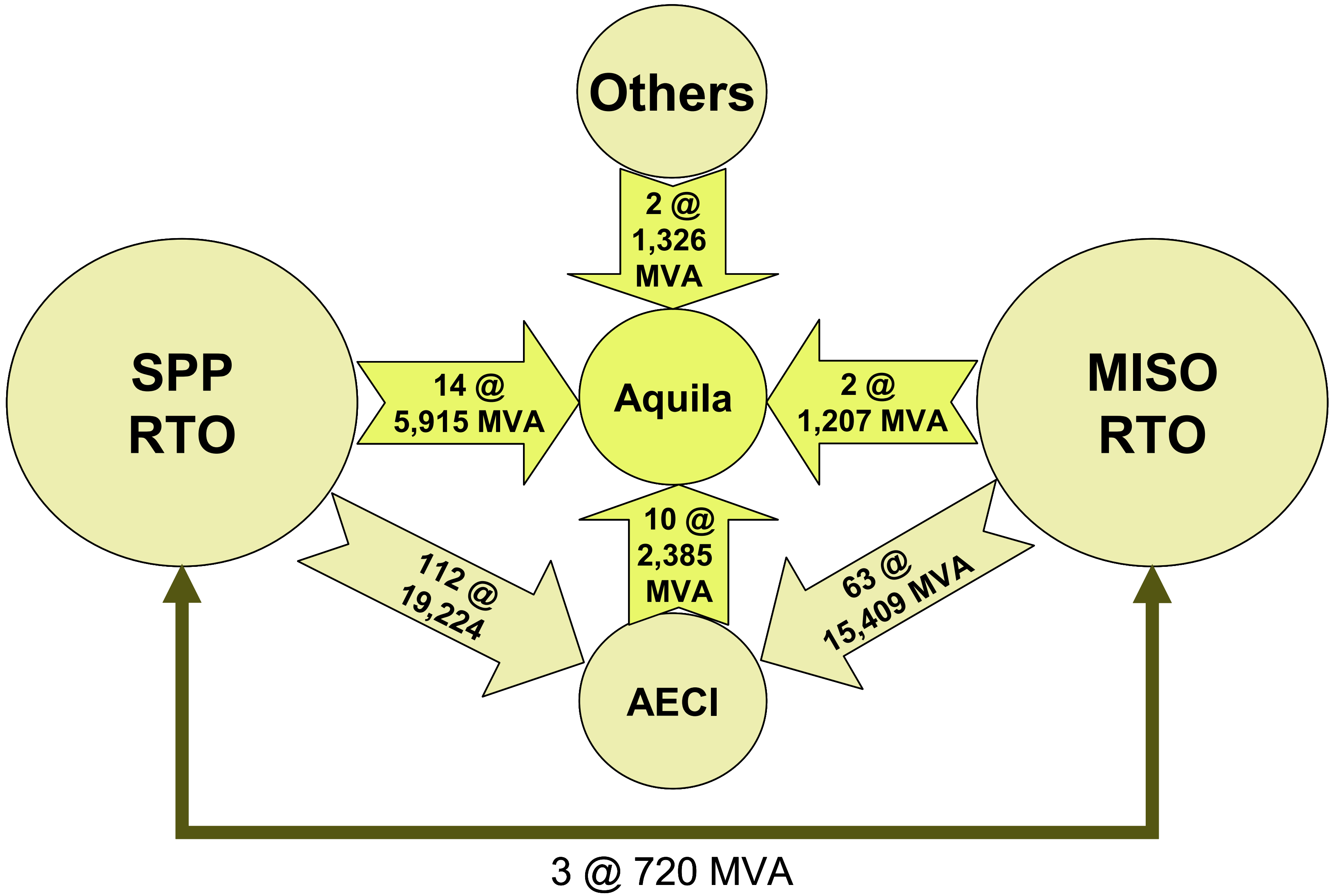
Aquila's Electrical Interconnections



Schedule 1

Tie Lines With Aquila:

No. Lines @ Summed MVA Capacities



Schedule 2