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Sponsoring Party:	City of Independence, Missouri
Case No:	EM-2007-0374
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BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

CASE NO: EM-2007-0374

REBUTTAL TESTIMONY OF

MARK J. VOLPE

ON BEHALF OF

THE CITY OF INDEPENDENCE, MISSOURI

REBUTTAL TESTIMONY
OF
MARK J. VOLPE

CASE NO: EM-2007-0374

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark J. Volpe. My business address is 1700 Pennsylvania Avenue, N.W., Suite 500, Washington, D.C., 20006-4725.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. Since June of 2007, I have been employed by the law firm of Jennings, Strouss & Salmon, PLC as a non-lawyer consultant. My firm has been retained by the city of Independence, Missouri ("City") to assist them in evaluating the effects of the proposed merger between Kansas City Power & Light Company ("KCPL) and Aquila, Inc. ("Aquila").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I hold a Bachelor of Science degree in Business Administration, majoring in accounting and legal studies, from Ohio Northern University (1981) and a Masters in Business Administration from Ashland University (1988). From March 2000 through April 2007, I worked for the Midwest Independent Transmission System Operator ("Midwest ISO") serving in the capacity as the company's Director of Regulatory Affairs. Prior to working for the Midwest ISO, I worked for Cinergy Corporation from 1997 to 2000 as a Senior Contract Analyst in the Energy Delivery Business Unit. Prior to that, I worked for FirstEnergy Corporation from 1987 to 1997.

My business background includes several years of experience in the development of unbundled transmission rates and ancillary service schedule filings in conjunction with initial Open Access Transmission Tariff ("OATT") of the Midwest ISO. I was involved in the negotiations that resulted in the formation of the Midwest ISO representing initially, FirstEnergy, and then Cinergy Corp. I participated in the Pricing Working Group and Transmission Owners Committee while the Midwest ISO was in the early stages of development. I have over twenty-years of energy and electric utility experience, having held numerous positions in federal regulatory affairs, rates, strategic planning, software quality assurance and financial information systems with Cinergy Services, Inc., FirstEnergy Corporation and Marathon Oil Company.

Q. PLEASE DESCRIBE YOUR CURRENT CONSULTING WORK WITH JENNINGS STROUSS.

A. As a non-lawyer consultant, I work with clients in the areas of retail and wholesale electric cost of service development, support and analysis. This consulting work also includes tariff matters on issues including, but not limited to revenue sufficiency guarantee charges, grandfathered agreements, and Regional

Transmission Organization membership evaluation criteria and analysis. I also provide energy market and transmission service related overviews for state regulatory commissions and consumer advocate groups; transmission expansion system planning, cost recovery mechanisms, transmission pricing proposal consulting; and interconnection agreement negotiations. My consulting work focuses primarily on representing the interests of municipally and cooperatively owned and operated electric systems around the country.

Q. WHAT WERE YOUR JOB RESPONSIBILITIES AT THE MIDWEST ISO?

A. As the Director of Regulatory Affairs for the Midwest ISO, my job responsibilities included the continued development of the OATT including the related tariff administration implementation and support of all regulatory filings with the Federal Energy Regulatory Commission ("FERC" or "Commission"). My job responsibilities also included coordination with the Midwest ISO's Transmission Owners on various ratemaking issues and the development of transmission policy, as well as, working on the resolution of seams issues between the Midwest ISO and its bordering entities such as PJM Interconnection, L.L.C. ("PJM") and the Southwest Power Pool, Inc. ("SPP").

For two years at the Midwest ISO, my responsibilities focused on the resolution of stakeholder issues in conjunction with the development of policy and procedures related to the drafting of the necessary rates, terms and conditions as embodied in the proposed Open Access Transmission and Energy Markets Tariff for the Midwest ISO ("Market Tariff"). The Market Tariff contains the rates, terms and conditions necessary to accomplish the implementation and current operation of the Midwest ISO's Day-Ahead and Real-Time Energy Markets (collectively "Energy Markets") and Financial Transmission Rights ("FTRs").

Once the Midwest ISO began commercial operations, as the regional transmission provider under the OATT in February 2002, and then subsequently under the Market Tariff when the Midwest ISO launched its Energy Markets in April 2005, my day-to-day responsibilities also included numerous instances where those parties subject to the rates, terms and conditions of service under the tariff would have questions regarding policy or interpretation of the tariff and in other cases parties filed formal disputes under the tariff or complaints with Commission. In these instances, I worked closely with Midwest ISO's legal department, including outside counsel, in the development of the Midwest ISO's policy, tariff interpretation and regulatory strategy related to resolving these disputes or complaints. I also helped represent the interests of the Midwest ISO in resolving these matters.

Q. HAVE YOU SPONSORED TESTIMONY BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("MPSC" OR "COMMISSION") OR ANY OTHER REGULATORY BODY?

A. Yes. I previously sponsored testimony before the Federal Energy Regulatory Commission ("FERC") on behalf of the Midwest ISO in FERC Docket No. ER01-780-000 concerning the Midwest ISO's Intervention and Protest of the withdrawal of Exelon Corporation, Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc. (collectively "ComEd") from the Midwest ISO. I also sponsored testimony in the Midwest ISO's Regional Transmission Organization ("RTO") Order No. 2000 supplemental compliance filing in FERC Docket No. RT01-87-000. After the Midwest ISO was conditionally approved as an RTO, I sponsored testimony in the unbundling of the Midwest ISO's Schedule 10 Administrative Cost Adder in FERC Docket No. ER02-111-000. Other sponsored testimony was filed in Docket No. ER02-1420-000 to explain the nature of the proposed Schedules 18 and 19 of the Resulting Company Open Access Transmission Tariff in conjunction with the proposed combination of the Midwest ISO and the SPP. I sponsored testimony in the initial Energy Markets tariff filing made on July 25, 2003 in Docket No. ER03-1118-000 related to the tariff construct, changes to the existing transmission service provisions to incorporate the markets, and to the stakeholder process. I sponsored testimony related to the revisions to Midwest ISO's Schedule 2 in Docket No. ER04-961-000 allowing for independent generators to receive compensation for providing reactive power. I filed testimony in Docket No. ER04-691-000 in conjunction with the second filing for the tariff provisions related to the implementation of Midwest ISO's Energy Market.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to explain that there are significant cost differences to the Applicants (and hence the Applicants' customers) depending whether KCP&L and Aquila, once merged, place all of the merged entities' electric assets in the same RTO such as SPP, or if the merged entity splits its RTO membership between SPP and the Midwest ISO.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. My testimony explains how the merged company's RTO decisions may potentially impact the Applicants' customers from a cost standpoint. I outline the key cost components of the two RTOs and explain the differing types of costs the Applicants' customers could potentially be exposed to given the distinct differences between the SPP and the Midwest ISO.

The testimony explains, compares and contrasts the key differences between the two RTOs related to: 1) the basic functions of their energy markets; 2) the mechanisms used to recover their respective RTO's administrative costs; 3) the potential exposure to energy market charges that are uplifted to load such as Revenue Neutrality Uplift "(RNU"); 4) the procurement of ancillary services; 5) rate pancaking for transactions between the various RTOs; 6) the RTO's plans for additional regional transmission infrastructure expansion and the associated cost allocation implications; and 7) the economic and reliability benefits which can be obtained as a result of a single dispatch.

Q. WHAT DOES THE APPLICATION STATE REGARDING THE COMPANIES' INTENTIONS FOR RTO PARTICIPATION?

A. According to the merger application before the MPSC, the Companies have not made a definitive decision as to which RTO the merged company will join and when. However, in response to data requests issued by the City, the Companies state that KCP&L will remain a member of SPP (see Independence Request 2-8, attached hereto), and that Aquila has filed for approval before the MPSC to become a member of the Midwest ISO (see Independence Request 2-9, attached hereto).

In either case, there are significant costs impacts to Applicants' retail and wholesale customers, including the City of Independence, who is a customer of the merged company, and its customers, depending on which direction the merged entity decides to take with regard to their RTO membership decision.

II. ENERGY MARKETS

Q. PLEASE BRIEFLY DESCRIBE IN GENERAL TERMS THE ENERGY MARKETS CURRENTLY OPERATED THE MIDWEST ISO.

A. The Midwest ISO operates a Day-Ahead and Real-Time Energy Market where Financial Transmission Rights are made available to hedge against the costs of congestion in a market based on the concept of Locational Marginal Prices ("LMP"). The Midwest ISO's Energy Market is similar to the market operated by the PJM Interconnection ("PJM"). LMP is the market clearing price for energy at a given pricing node in the Midwest ISO region that is equivalent to the marginal cost of serving demand at the pricing node. This market allows market participants to offer their supply of generation and bids from load to buy or consume energy in a financially binding day-ahead energy market. Market participants can balance their energy requirements in real-time and receive credits against the day-ahead costs of congestion based on their allocation of FTRs.

The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next Operating Day based on LMP. The Day-Ahead Energy Market is cleared using Security-Constrained Unit Commitment ("SCUC") and Security-Constrained Economic Dispatch ("SCED") computer programs to satisfy energy demand bid requirements (including Fixed Demand Bids, Price-Sensitive Demand Bids, and Virtual Demand Bids) and supply requirements (Fixed Supply Offer, Price-Sensitive Supply Offers, and Virtual Supply Offers) of the Day-Ahead Energy Market. The results of the Day-Ahead Energy Market clearing include hourly LMP values, hourly demand and supply quantities, and hourly Balancing Authority (BA) Net Scheduled Interchange ("NISH") are posted as the day-ahead schedules for all market participants. Network resources "must-offer" their generation into the Day-Ahead Energy Market.

The Real-Time Energy Market is a "balancing" market in which the LMPs are calculated every five minutes, based on Midwest ISO dispatch instructions and actual system operations. The same SCED program used in the Day-Ahead Market is used in Real-Time to identify dispatch signals to be sent to generating units. Generators that are available but not selected in the Day-Ahead Energy Market may alter their Offers for use in the Real-Time Energy Market.

The FTR Market provides an opportunity for Market Participants to acquire Financial Transmission Rights ("FTRs") to manage the risk of congestion cost in the Day-Ahead Energy Market. FTRs are financial instruments and do not represent a physical right for delivery of energy. FTRs provide a mechanism to hedge the congestion costs between the Point of Receipt and Point of Delivery of the FTR in the Day-Ahead Market. Only Market Participants can hold FTRs.

Q. PLEASE BRIEFLY DESCRIBE THE ENERGY MARKET CURRENTLY OPERATED BY THE SPP AND BRIEFLY CONTRAST THIS MARKET WITH MIDWEST ISO'S ENERGY MARKET.

A. The 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. Under the SPP market, the Energy Imbalance Service ("EIS") is the dollar amount associated with imbalance energy. The calculation is based on the amount of imbalance energy (in megawatts) multiplied by a price at a specific point on the energy grid. SPP conducts a regional dispatch calculated using a security constrained, offer-based economic dispatch ("SCED") every 5 minutes. More simply put, in many ways the SPP is a spot balancing market; there is no day-ahead market and SPP does not utilize the LMP concept, as is the case in the Midwest ISO. In its place, SPP relies upon Locational Imbalance Pricing at a nodal level. Generation resources make voluntary offers of their resources for the EIS or may self-commit their resources. This is in contrast to the Midwest ISO market where Network Resources are required to submit offers to supply their generation in the Day-Ahead. The EIS is settled on an hourly basis. The major difference between the SPP model and the Midwest ISO's market is that there is no financially binding Day-Ahead energy market within SPP's market design and the majority of the transactions occur on a bilateral basis. Furthermore, in SPP there are no FTRs to provide customers with the opportunity to hedge against the costs of congestion as is the case in an LMP based market. SPP's market is rooted in a defined set of physical transmission rights.

While there are some similarities, there are major differences between the two markets. SPP is a voluntary market rooted in a bilateral transaction where market participants can obtain balancing energy from a spot energy market, using Locational Imbalance Pricing and a set of physical rights. Participation in the Midwest ISO's market is mandatory for generators that are network resources, and the Midwest ISO uses a two-settlement system based on LMP where congestion costs are hedged using an allocation of FTRs. The Midwest ISO's market design is more complex.

Q. WHY IS THE RTO DECISION OF THE MERGED COMPANY OF PARTICULAR INTEREST TO THE CITY OF INDEPENDENCE?

A. Independence has direct physical interconnections, and currently has interconnection agreements in place, with both KCPL and Aquila**.** Additionally, Independence has one interconnection with Associated Electric Cooperative, Inc. which is not part of the SPP energy imbalance market. On May 19, 2006, KCPL noticed the termination in 2011 of its long-standing Municipal Participation Agreement ("MPA") with Independence, which addresses the interconnected operations of the parties' systems. A similar Municipal Participation Agreement between Independence and Aquila, while still in force, contains a forty-eight month notice provision, which either party may exercise at any time.

As mentioned in the answering testimony of Paul N. Mahlberg, Independence also has existing agreements with both KCPL and Aquila pursuant to which Independence purchases capacity and/or energy from each of the companies. Under the MPA with KCPL, Independence purchases of 90 megawatts of base load power and energy from Montrose, a large, base load, coal-fired unit owned by KCPL providing for approximately 60 percent of the City's energy requirements each year. These arrangements include purchases of a portion of the capacity and energy from Montrose, a large, base load, coal-fired generating plant owned by KCPL. KCPL and Aquila, along with certain other participants, are currently developing Iatan 2, another large, base load, coal-fired generating plant. The Missouri Joint Municipal Electric Utility Commission ("MJMEUC"), of which Independence is a member, is among the parties that will jointly own Iatan 2. Independence has contracted with MJMEUC to purchase approximately 50 MW of the Iatan 2 capacity and associated energy when the plant becomes operational in 2010. The City of Independence has also contracted for a share of approximately 55 megawatts from Omaha Public Power District's Nebraska City 2 unit. This unit is currently under construction and is expected to begin commercial operation in 2009.

Finally, Independence has border customer agreements with both KCPL and Aquila for wholesale electric service to customers located along the service territory boundaries. Under these agreements, the Applicants and Independence have made arrangements to serve their respective border customers through direct connection to the other parties' distribution facilities. Post-merger protection for appropriate cost recovery and continued access to transmission service must remain available for these customers.

As described above, there are significant differences between the respective markets operated by the Midwest ISO and the SPP. Currently, it is my understanding that KCPL participates in SPP's energy imbalance market and they are part of SPP's reliability region. Similarly, Aquila joined the Midwest ISO as a conditional member when the Midwest ISO initially began providing transmission service in 2002, however their conditions to becoming a full-fledged transmission owning member of the Midwest ISO never were met or waived and as a result Aquila has only been taking reliability coordination services from the Midwest ISO for some time.

The City of Independence cannot even begin the process of attempting to analyze the impact of the RTO membership decision on its customers until KCPL and Aquila make a commitment as to their RTO plans. For example, if the merged company decides to put all of the merged company's assets in SPP, then this creates one set of workable assumptions, or if the newly merged company places all of the assets in the Midwest ISO this creates another fact scenario. However, if the merged company splits the individual operating subsidiaries' assets between the two RTOs, then this creates a whole new set of circumstances parties would need to analyze from a cost and benefits perspective. I also believe the MPSC would prefer that the Companies provide cost benefit analyses either way in order to address the RTO membership issue and the underlying impact on ratepayers before approving the proposed merger.

III. RTO ADMINISTRATIVE COST RECOVERY

Q. PLEASE DESCRIBE SPP's ADMINISTRATIVE COST RECOVERY MECHANISM.

A. Under the SPP tariff, the costs of operating the RTO are recovered under Schedule 1-A, the Tariff Administration Charge which is applied to all transmission service under the SPP tariff and covers the expenses related to administration of their tariff. For point-to-point transmission service this charge is capped at $0.20 per MW per hour for all capacity reserved. For Network Integration Transmission Service ("NITS") this charge is also capped at $0.20 per MW per hour for the 12 month average of the transmission customer's coincident zonal demands used to determine the demand charges under for NITS service per Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for point-to-point transmission service as it is for NITS.

For each calendar year, SPP establishes a rate for this administration charge by dividing projected expenses based on its budget for the calendar year divided by the projected annual Schedule 1-A billing units for the calendar year. SPP provides a true-up to reconcile actual amounts with budgeted figures and adjusts the charges for the following calendar year to reflect either over or under recoveries of its costs from the prior year to allow SPP to only recover its actual costs.

Q. PLEASE DESCRIBE THE MIDWEST ISO's ADMINISTRATIVE COST RECOVERY MECHANISMS.

A. The Midwest ISO recovers its administrative costs under Schedules 10, 16 and 17 of their tariff. Schedule 10 is used to recover the costs associated with the provision of transmission service and reliability coordination services. There are two basic types of transmission service provided under the tariff - point-to-point and network service. Point -to-point transmission customers and network service customer pay Schedule 10 based on a two-part rate. Each month, the Midwest ISO determines two rates, a "Reserved Capacity Rate" and an "Energy Rate" for application under Schedule 10. The two rates are necessary because each is multiplied by a different type of billing determinant. The Reserved Capacity Rate is multiplied by billing units of Reserved Capacity, and the Energy Rate is multiplied by billing units of MWhs for scheduled energy. For point-to-point transmission customers the reserved capacity portion of the rate uses the reserved capacity in megawatts as the billing determinant to be multiplied by the Reserved Capacity Rate. Network customers use their network load as the basis for this portion of the billing calculation. During the transition period, which ends on January 31, 2008, the Schedule 10 cost recovery adder for both rates is capped at a rate of 15 cents/MWh. The portion of the Midwest ISO's monthly capital and operating costs in excess of the 15 cents/MWh cap shall be added to their pre-operating costs and the sum shall collectively be known as the deferred costs. Transmission service under the tariff for all bundled retail customers and wholesale transmission customers subject to Grandfathered Agreements are required per Commission order to pay an allocation of the Midwest ISO's Schedule 10 administrative costs. Schedule 10 also allows for true-ups between the budgeted costs used to set the monthly rate and the Midwest ISO's actual expenditures. There are also provisions to address crediting of withdrawal fees paid by departing members against the monthly costs to be recovered.

The Midwest ISO recovers its costs of administering the FTR Market under Schedule 16. FTR administrative costs are recovered from market participants actually holding FTRs. The costs incurred in administering the FTR market include the costs associated with: 1) coordination of FTR bilateral trading; 2) administration of FTRs through allocation, assignment, auction or any other process accepted by the Commission; 3) support of the on-line, Internet-based FTR tool; 4) "simultaneous feasibility" analyses to determine the total combination of FTRs and Option B GFA entitlements that can be outstanding and accommodated by the Transmission System at a given point in time; and, 5) the administration of FTRs and revenue distribution.

The billing determinants for the FTR Administrative Service Cost Recovery Adder is the total amount of FTR volume for all FTR Holders and Option B GFA entitlements, expressed in MW. The FTR Administrative Cost Recovery Adder rate is calculated by taking all of the costs associated with the provision of the FTR market (direct operating costs, indirect operating costs, and depreciation of hardware/software, interest, and debt amortization) and dividing by the estimated

FTR volume in megawatts. Each FTR Holder and their associated FTR volume is multiplied by the rate to determine their allocation of Schedule 16 costs on a monthly basis. Schedule 16 also allows for true-ups between the budgeted costs used to set the monthly rate and the Midwest ISO's actual expenditures. There are also provisions to address crediting of withdrawal fees paid by departing members against the monthly costs to be recovered.

The Midwest ISO recovers its costs of operating the Day-Ahead and Real-Time Energy Markets from market participants under Schedule 17 - The Energy Market Administrative Cost Recovery Adder. The costs incurred in providing these markets include the costs associated with: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) enabling the least-cost, security-constrained commitment and dispatch of generating resources to serve load in the Control Areas of the Midwest ISO while also establishing a spot energy market. A market participant acting as an entity responsible for a grandfathered agreement will be assessed Schedule 17 charges. In general, Schedule 17 charges are associated with all physical injections and withdrawal schedules of energy submitted by the market participant and Schedule 17 is also charged in association with service taken pursuant to Option A, Option B, Option C or Carve-Out GFA Tariff provisions as ordered by the Commission. Virtual offers and bids clearing in the Day-Ahead market also pay Schedule 17, even though these transactions are not actual physical injections or withdrawals of energy. The Energy Market Administrative Cost Recovery Adder rate is calculated by taking all of the costs associated with the provision of the energy market (direct operating costs, indirect operating costs, and depreciation of hardware/software, interest, and debt amortization) and dividing by the estimated injections, withdrawals and virtual transaction volume in MWhs. For each market participant, their associated market transaction volume is multiplied by the rate to determine their allocation of Schedule 17 costs on an hourly basis. Schedule 17 also allows for true-ups between the budgeted costs used to set the monthly rate and the Midwest ISO's actual expenditures. There are also provisions to address crediting of withdrawal fees paid by departing members against the monthly costs to be recovered.

IV. UPLIFT COSTS

Q. WHAT IS MEANT BY THE TERM UPLIFT COSTS?

A. Generally speaking, in the world of ratemaking and cost allocation, the underlying principle of cost causation is followed in that those parties causing a particular cost to be incurred and are arguably benefiting from the incurrence of such costs are the same party who should pay. These cost causers are included in the universe of billing determinants found in the denominator in developing a rate. An uplift of costs occurs when there is no causal link between those parties causing a particular cost to be incurred and the beneficiary associated with the incurrence of those costs. For example, the cost of constructing the nation's interstate highway system is allocated to all taxpayers regardless of whether they actually use the highway system or not. Use of the highway occurs to everyone free of charge with the costs uplifted to all taxpayers. The obvious contrast to the uplifting of costs for the nation's interstate highway system to the taxpaying public would be a turnpike or toll road. In this case, all users of the turnpike or toll road pay a uniform rate, but only when actually using the facility. The party managing the operation of the toll road, such as the state turnpike commission, divides the total costs of operations, maintenance, wages, taxes, insurance and other costs by the expected usage or billing determinants to calculate rates. These rates for turnpikes are often distance-based (the farther you go the more you pay) and higher for those parties (i.e. heavier tractor trailers) contributing more to the physical depreciation because of wear and tear. They bear more of the costs for the required maintenance.

In the area of electric utility ratemaking and energy markets the same holds true. There are, in some instances, cost causers who can readily be identified and allocated an equitable share of the associated costs and then there are some types of costs where it is virtually impossible to establish a causal link, therefore these costs are uplifted generally to all consumers typically on a load ratio share for example.

Q. WHAT ARE THE TYPICAL TYPES OF COSTS WHICH ARE UPLIFTED TO LOAD IN SPP AND THE MIDWEST ISO?

A. The recovery of the RTOs administrative costs, as previously discussed, are an example of costs that are uplifted to load in both RTOs. However, both RTOs as a result of their energy markets include charges commonly referred to as the Revenue Neutrality Uplift ("RNU") which is an inherent component of their respective market design. The SPP RNU Uplift, however, differs significantly from the Midwest ISO's RNU Uplift.

Q. PLEASE DESCRIBE RNU AS IT PERTAINS TO SPP'S ENERGY IMBALANCE MARKET?

A. Under the SPP tariff Section 5.6 includes the provisions and related calculations regarding RNU. To the extent the sum of the charges calculated below under a), b), c) and d) are not equal to the sum of the credits calculated under Attachment M for any hour in the Operating Day, SPP performs the following calculations for each applicable hour of the Operating Day for each market participant in order to ensure that the total charges are equal to the total credits in each applicable hour.

(a) For each hour, the System Imbalance Uplift Charge/Credit shall be equal to the sum of:

(i) the sum of all Net Energy Imbalance Service Charge/Credits in that hour;
(ii) the sum of all Over Scheduling Charges in that hour;
(iii) the sum of all Under Scheduling Charges in that hour;
(iv) the sum of all Uninstructed Deviation Charges in that hour;
(v) the sum of all Recalculated LIP Credits in that hour;
(vi) the sum of all Designated Balancing Authority Loss Charges in that hour; and,

(vii) the sum of all Self-Provided Loss Credits in that hour.

b) For each hour, a Market Participant shall have an Energy Imbalance Service Uplift Obligation at each Settlement Location that is equal to the sum of:

(i) the absolute value of that Market Participant's actual net generation at that Settlement Location;

(ii) the absolute value of that Market Participant's Reported Load at that Settlement Location;

(ii) the absolute value of that Market Participant's bilateral transaction purchases external to the SPP Region at that Settlement Location; and,

(iv) the absolute value of that Market Participant's bilateral transaction sales external to the SPP Region at that Settlement Location.

(c) For each hour, each Market Participant's Energy Imbalance Uplift Charge/Credit at each Settlement Location shall be equal to:

$EIUC = SIC * (EISUO_{MP}$ / sum of $EISUO_{MP})$, where;

EIUC = Market Participant's Energy Imbalance Uplift Charge/Credit;

SIC = System Imbalance Charge/Credit;

$EISUO_{MP}$ = Market Participant Energy Imbalance Service Uplift Obligation

(d) For each hour, each Market Participant's total Energy Imbalance Uplift Charge/Credit shall be equal to the sum of that Market Participant's Settlement Location specific Energy Imbalance Uplift Charge/Credit.

Q. PLEASE DESCRIBE RNU AS IT PERTAINS TO THE MIDWEST ISO'S ENERGY MARKET?

A. Based on the Midwest ISO's Market Settlements Business Practices Manual Appendix A, the Real-Time Revenue Neutrality Uplift Amount is a charge type set up as a revenue distribution balancing mechanism for charges and credits that have no other distribution method to market participants. On an hourly basis, all charges and credits that have no other distribution method are summed, and the subsequent total charge or credit for the hour is distributed to market participants based on their Load Ratio Share ("LRS"). A market participant's LRS is determined by: 1) summing the volumes of the market participant's assets that are consuming energy (acting as load) for an hour plus the sum of all Real-Time Physical Bilateral Transaction volume where the market participant is buying the transaction volume for export out of the Midwest ISO (these are wheel out schedules from the Midwest ISO and do not include wheel through schedules) net of Carve-Out Grandfathered Agreement transactions (in MW) and absent a defined set of LRS exempt exclusions, and 2) dividing the result by the sum of all market participant's assets that are consuming energy during the same hour plus the sum of all Real-Time Physical Bilateral Transaction volume where market participant's are buying the transaction volume for export out of the Midwest ISO (these are wheel out schedules from the Midwest ISO and do not include wheel through schedules) net of Carve-Out Grandfathered Agreement transactions (in MW) and absent a defined set of LRS exempt exclusions.

The following charges and/or credits are distributed through this charge type:

1) Uninstructed Deviation Charge Distribution Uplift

2) Revenue Inadequacy Uplift

3) JOA Uplift

4) GFA Option B Financial Bilateral Transaction Congestion Rebate Distribution Amount Uplift

5) Carve-Out GFA Congestion Rebate Distribution Amount Uplift

6) Real-Time Revenue Sufficiency Guarantee Make Whole Payments Second Pass Distribution Uplift

For the purposes of this testimony there is no need to go into a detailed explanation of each specific component of the RNU, however my testimony later explains some of the current issues at the Midwest ISO involving the last component of the RNU mentioned above, the Real-Time Revenue Sufficiency Guarantee Make Whole Payments Second Pass Distribution Uplift.

Q. PLEASE BRIEFLY EXPLAIN HOW THE MIDWEST ISO'S REAL-TIME REVENUE SUFFICIENCY GUARANTEE ("RSG") IS CHARGED TO MARKET PARTICIPANTS?

A. RSG costs or make whole payments are paid to generation resources which are committed by the Midwest ISO for reliability purposes. These RSG costs consist of payments to generators to make up the difference in those instances when their market revenues do not cover their start-up, no-load and incremental energy costs. These costs are not considered to be an uplift because market participants, under the terms of the Midwest ISO's tariff in Section 40.3.3.**A.**, there are detailed provisions requiring that the RSG costs are to be paid by those market participants based on their relative share of their deviations between their day-ahead schedules and what actually occurred in the real-time energy market in proportion to all other deviations during the hour being settled.

Q. IF RSG CHARGES ARE TO BE PAID BY MARKET PARTICIPANTS ACCORDING TO SECTION 40.3.3.A. AND FOLLOW THE PRINCIPLE OF COST CAUSATION, THEN PLEASE EXPLAIN WHY THIS IS AN UPLIFTED COST UNDER THE MIDWEST ISO'S TARIFF?

A. Section 40.3.3.A. of Midwest ISO's tariff begins with the phrase, "On any Operating Day when a Market Participant physically withdraws Energy in the Real-Time…." and this single provision in the tariff has been an issue from the inception of the Midwest ISO's market in April 2005 and the subject of tenuous regulatory proceedings at the Commission and causing complex resettlements for the Midwest ISO.

As background, the Midwest ISO's Day-Ahead Energy Market allows market participants to submit virtual supply offers. These virtual transactions that clear in the day-ahead do not represent actual physical injections and/or withdrawals of energy and are generally used by market participants as a financial tool to hedge against real-time price exposure. Many of the market participants in the Midwest ISO's market do not own physical generation or serve end-use customers, these parties only participate in the market through virtual transactions and therefore these "virtual players" have no physical withdraw of energy in the real-time. As a result of the market participants that are purely "virtual players", (i.e. submitting virtuals only and not physically withdrawing energy) there is a mismatch between the development of the denominator used in developing the rate for the RSG charge, which includes all of the virtual transaction's deviations, and then language at the beginning of Section 40.3.3.A. requiring only market participants actually physically withdrawing energy during the day has the impact of excluding deviations included the denominator attributable to virtual transaction from paying the first pass Real-Time RSG charges. These uncollected dollars from the first pass are passed onto the second pass RSG distribution where these costs are uplifted to load on a load ratio share basis. Any Real-Time RSG costs not collected in the first pass distribution are being passed on to load via the Real-Time Revenue Sufficiency Guarantee Make Whole Payments Second Pass Distribution Uplift.

The Midwest ISO is currently going through a process with its stakeholders where the entire RSG cost allocation method will be redesigned by the RSG Task Force resulting in new proposed tariff provisions being submitted to the Commission in the third or fourth quarter of 2007.

Q. ARE THERE ANY OTHER COSTS IN THE MIDWEST ISO MARKET THAT ARE TYPICALLY UPLIFTED TO LOAD?

A. Yes. The Midwest ISO's Energy Market also includes a Miscellaneous Charge Type that is used under a variety of circumstances. This charge is uplifted to load on a load ratio share basis.

V. ANCILLARY SERVICES

Q. WHAT ARE ANCILLARY SERVICES AND HOW HAS THE PROVISION OF THESE SERVICES CHANGED UNDER THE RTO TARIFFS?

A. In 1996, when the FERC unbundled wholesale transmission service under Order No. 888, part of the unbundling included the requirement that transmission customers had to take and pay for six ancillary services identified as follows:

SCHEDULE 1 - Scheduling, System Control and Dispatch Service

SCHEDULE 2 - Reactive Supply and Voltage Control from Generation Sources Service

SCHEDULE 3 - Regulation and Frequency Response Service

SCHEDULE 4 - Energy Imbalance Service

SCHEDULE 5 - Operating Reserve - Spinning Reserve Service

SCHEDULE 6 - Operating Reserve - Supplemental Reserve Service

There is no need to go through a technical description and the associated billing calculation for each of the ancillary services for the purposes of this testimony. With the exception of Schedule 1, these services are provided by generation resources in order to maintain system reliability and for the most part, the six ancillary services were provided by transmission providers, who were traditional vertically integrated utilities owning generation, transmission and distribution assets, where the ancillary services were provided under cost-based rate schedules included in the utilities' individual open-access transmission tariffs. The key point is that, in all cases the parties filed cost-based rate schedules and each had to prove their generation resources were technically capable of providing the ancillary service. Transmission customers had the option of either 1) self-supplying; 2) making arrangements with third-party providers or; 3) the transmission provider could procure the required ancillary services on behalf of the transmission customer.

When the RTOs, such as the Midwest ISO, PJM and SPP, emerged as the regional providers of transmission service the obligation for transmission customers to provide their ancillary services remained. The only service the RTO was capable providing itself was Schedule 1, the remaining ancillary services or generation related ancillary services were provided from those parties with the required cost-based rate schedules on file with the Commission. Under the RTO's tariffs, transmission customers still had the option of self-supplying, making arrangements with third-party providers or RTO acted as the provider of last resort if the transmission customer did not provide the required ancillary services themselves or make arrangements with a third-party.

Q. PLEASE DESCRIBE THE PROCESS AND COSTS INHERENT IN PROCURING ANCILLARY SERVICES UNDER THE SPP TARIFF.

A. Under the SPP tariff, all transmission customers are required to purchase Schedules 1 and 2 from SPP under the cost-based rate schedules as found in the SPP Tariff. Schedules 3, 5 and 6 can either self-supplied by the transmission customer, or the customer can make arrangements with a third-party provider or the customer can have SPP provide the required ancillary services on their behalf. When SPP purchases Schedules 3, 5 and 6 on behalf of the customer, the costs to be passed on to the customer remain subject to the same cost-based rates the generation resources currently have on file with the Commission as described above. Also note that Schedule 4 has been replaced by SPP's Energy Imbalance Service.

Q. PLEASE DESCRIBE THE PROCESS AND COSTS INHERENT IN PROCURING ANCILLARY SERVICES UNDER THE MIDWEST ISO TARIFF.

A. Under the tariff provisions currently in effect under the Midwest ISO's tariff process, transmission customer options and cost-based rates are similar to the provisions under the SPP tariff, except energy imbalance service is provided under the Midwest ISO's existing real-time energy market. However, the Midwest ISO has recently filed to replace the cost-based ancillary services provided under Schedule 3, 5 and 6 with their proposed Ancillary Services Market ("ASM").

Q. PLEASE DESCRIBE THE MIDWEST ISO's PROPOSAL TO IMPLEMENT ASM.

A. According to the Midwest ISO's filing letter in their filing made September 14, 2007 in FERC Docket No. ER07-1732-000, the ASM proposal, with an effective date of June 1, 2008, will change the existing Day-Ahead and Real-Time Energy Markets by: 1) providing for integration of Operating Reserves into the existing two-market (*i.e.*, Day-Ahead and Real-Time) settlement of Energy; 2) providing for the simultaneously co-optimized commitment and dispatch of Energy and Operating Reserves to minimize total costs and incorporate Opportunity Costs into Day-Ahead and Real-Time Market-Clearing Prices ("MCP") of Operating Reserves; 3) integrating scarcity pricing, through the use of Demand Curves, into the Day-Ahead and Real- Time Markets as part of the co-optimization process; 4) establishing the foundation and support for greater market participation by Demand Response Resources to provide Operating Reserves in a manner that is comparable to Generation Resources and that will be consistent with Commission-approved ERO standards; and 5) establishing comprehensive and efficient procedures for addressing pre-Emergency and Emergency conditions, including the integration of Demand Response Resources into such procedures.

In addition, the proposed tariff modifications incorporate changes necessary to accommodate the transfer of certain Balancing Authority functions from the existing Balancing Authorities to the Midwest ISO. The Midwest ISO will function as a North American Electric Reliability Council ("NERC") certified Balancing Authority for the Midwest ISO Balancing Authority Area, working closely in connection with the existing Balancing Authorities, which will continue to function as Local Balancing Authorities ("LBAs"). Following the transfer of such authority, the Midwest ISO Balancing Authority will procure required Operating Reserves through the proposed Ancillary Services Markets.

Q. WHAT IS THE MAJOR DIFFERENCE BETWEEN THE COSTS OF PROCURING ANCILLARY SERVICES UNDER MISO's ASM PROPOSAL VERSUS SPP?

A. The Midwest ISO's ASM proposal will provide for the simultaneously co-optimized commitment and dispatch of Energy and Operating Reserves to minimize total costs and incorporate Opportunity Costs into Day-Ahead and Real-Time Market-Clearing Prices ("MCP") of Operating Reserves. The costs of procuring reserves under the ASM proposal will be a function of the co-optimized commitment and dispatch of energy and operating reserves resulting in MCP for operating reserves. This is in contrast to the cost-based rates in effect for Schedules 3, 5 and 6 under the SPP tariff. The procurement of ancillary services under the ASM proposal will have a cost impact once this market is implemented in spring 2008. The benefits of the ASM project and the future impact on ancillary services costs for the City of Independence cannot be ascertained until KCPL makes a firm commitment regarding their RTO membership intentions.

VI. RTO RATE PANCAKING

Q. PLEASE DESCRIBE WHAT IS MEANT BY THE TERM RATE PANCAKING.

A. The term rate pancaking applies to the stacking or the additive impact as it relates to transactions for transmission service that utilize multiple transmission providers systems. For example, in moving energy from a generation resource physically located in transmission provider A's footprint, across transmission provider's B system to a load located within transmission provider C's transmission system, there can be as many as 3 separate charges for the transmission service associated with the use of the three transmission systems. This example ignores the real costs of both congestion and losses. These charges are additive and result from use of the separate transmission systems on a contract path basis without taking into account the laws of physics under the understanding that a given transaction may actually use other transmission systems not on the contract path that actually carried the flow. This adjacent system will not be compensated because they are not on the contract path. Rate pancaking is a barrier to competition because it is distance sensitive -- it gives generation resources located close to a load an economic advantage in serving the load due to the multiple transmission charges in place versus what may be a more economic resource that happens to be located farther away from the load. The Commission has encouraged policy focused on eliminating rate pancaking as a means to put all generation resources on a level playing field. There is no rate pancaking on transactions within the RTOs, any resource inside the RTO can serve any load within the same RTO for a single zonal rate associated with the load.

Q. PLEASE DESCRIBE HOW TRANSMISSION RATES APPLY FOR TRANSACTIONS BETWEEN THE MIDWEST ISO AND SPP.

A. On transactions from a generation resource in the Midwest ISO to a load physically located in SPP and vice-versa, the transmission customer will pay two transmission charges. One for drive-out transmission service allowing for the generation to exit the Midwest ISO, at one of the interfaces to SPP, and a second charge associated with the load zone side of the transaction in SPP. The same logic would hold true if the transaction sourced in SPP and the sink was in the Midwest ISO - there would be two charges for the transmission service. Rate pancaking remains on inter-RTO transactions between the Midwest ISO and SPP. In contrast, transactions within the Midwest ISO, or within SPP, do not experience pancaked transmission charges.

Q. IS THIS TRUE FOR ALL TRANSACTIONS INTO OR OUT OF THE MIDWEST ISO?

A. No. As between the Midwest ISO and the Pennsylvania-Jersey-Maryland ("PJM") region rate pancaking has been eliminated due to the movement toward a "joint and common" market and the elimination of the "seam" between the two regions. As a result of the Seams Elimination Cost Allocation proceedings in FERC Docket No. EL02-111-000, *et al.*, there is no pancaking of transmission rates on transactions between the Midwest ISO and PJM. This generally means that, for transactions from a generation resource in the Midwest ISO to a load physically located in PJM and vice-versa, the transmission customer pays only for the transmission charges associated with the load zone side of the transaction. There is no "joint and common" market between the Midwest ISO and SPP and there remains a "seam" between the two regions. Thus, as explained above, transactions between the SPP and the Midwest ISO incur pancaked transmission charges.

VII. FUTURE TRANSMISSION EXPANSION COSTS

Q. PLEASE DESCRIBE THE CURRENT TRANSMISSION EXPANSION PLAN AND THE ASSOCIATED ESTIMATED COSTS FOR THESE INITIATIVES CURRENTLY UNDERWAY AT SPP.

A. The Extra High Voltage ("EHV") Overlay Transmission Expansion Report, which was independently prepared by InfraSource Technology and PowerWorld Corporation, provides a strategic assessment of how to meet SPP's future reliability and capacity needs through the use of a 500 kV and 765 kV transmission system overlaying the existing SPP footprint and integrating with the existing EHV systems of Entergy, the Midwest ISO, and PJM. The project evaluated the performance of steady state analysis to verify that the final recommended package of projects satisfies reliability criteria and to identify reinforcements that may be necessary on underlying, lower-voltage facilities. For the past year, the Cost Allocation Working Group has been discussing a variety of proposals regarding possible cost allocation methodologies to recover the associated costs of transmission investment. Of the alternatives presented, the preferred alternative includes construction of 890 miles of 500 kV lines and 1390 miles of 765 kV lines at an estimated total cost of $4.85 billion dollars. Another related task force examining a variety of transmission facilities related issues is the Transmission Ownership/Construction Task Force.

Second, in the emerging area of wind development, a presentation was recently made to SPP's Control Area Working Group to inform them of the cost and benefit analysis of wind energy by the Wind Coalition. According to The Wind Coalition, the SPP region has some of the greatest and most abundant wind resources in the country, with a potential location for wind development being the Kansas Panhandle, but current cost recovery protocols for economic transmission projects have resulted in very few projects. The wind industry supports the concept of base funding for these projects. Assurance of cost recovery for transmission owners is necessary for construction of a reliable and efficient transmission grid. Improved transmission reduces constraints and facilitates efficient delivery of the most economic resources, reducing costs to the end user.

Q. PLEASE DESCRIBE THE CURRENT TRANSMISSION EXPANSION PLAN AND THE ASSOCIATED ESTIMATED COSTS FOR THESE INITIATIVES CURRENTLY UNDERWAY AT THE MIDWEST ISO.

A. This Midwest ISO Transmission Expansion Plan 2006 ("MTEP 06") is the third regional expansion plan issued by the Midwest ISO. The plan will substantially improve electric power grid performance in the Midwest by ensuring continued compliance with national electric reliability standards, by relieving the most significant points of congestion on the grid, and by facilitating the development of new base load and renewable generation resources. The MTEP 06 report describes the currently recommended transmission needs for the Midwest ISO transmission system. In accordance with the Transmission Owners' Agreement, approval of the Midwest ISO Plan by the board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities. The MTEP 06, as the regional transmission expansion plan, has identified 416 projects comprised of 738 planned or proposed facility additions or enhancements representing an investment of $3.6 billion through 2011.

Q. HOW ARE THE COSTS OF THE MTEP 06 ALLOCATED TO CUSTOMERS?

A. The Regional Expansion Criteria and Benefits ("RECB") has been the result of a three-year stakeholder process which has been bifurcated into two MTEP cost allocation methodologies. "RECB I" was the initial filing that was directed on a narrow subset of projects that were deemed to be transmission reliability required projects and generator interconnection projects. "RECB II" is a more complicated analysis for Regionally Beneficial Projects (projects not required solely for reliability purposes). The reliability project procedures were filed with FERC on October 7, 2005 and conditionally approved by FERC on February 3, 2006.

A cost sharing methodology for Regionally Beneficial Projects developed into a tariff submittal that was filed on November 1, 2006. RECB I proposed changing the crediting mechanism on generator interconnection upgrades from 100% credit for generator financed upgrades to 50%. The costs for high voltage Network Upgrades above 345 kV would be allocated 20% across the entire Midwest ISO

Region on a "postage stamp" basis and 80% to a sub-regional set of zones physically located nearer to and including the zone where the Network Upgrade would be constructed, based on a flow distribution factor calculation. Stakeholders generally acknowledged a system wide benefit to high voltage projects within the footprint and eventually agreed to the socialized sharing of up to 20% of the cost of a high voltage project predicated solely on reliability as a "postage stamp" component of cost allocated on a load ratio share to all Midwest ISO load zones. This would be the first time that a mechanism is in place that moves costs in base rates between rate zones on a "base rate" allocation rather than a transactional allocation. The Midwest ISO's Real-Time energy market made a transaction based allocation of the transmission expansion costs impossible because the pairing of the buyer and seller, similar to the relationship in a bilateral contract, is lost.

The RECB II stakeholder efforts to construct a cost sharing mechanism for all Regionally Beneficial Projects debated how to allocate costs that are inextricably linked to the expansion planning processes and how to properly evaluate the benefits associated with proposed transmission upgrades. The desire to construct a method where it is clear that the customers who will benefit from an investment will pay for that investment over the useful life of the asset. However, as the useful life of the project's assets are examined, the reality of allocating the costs associated with the benefits for a 40-year investment that does not begin to accrue benefits for 10 years from the present day, there is a natural erosion of confidence in transmission planners' ability to forecast with precision which customers will benefit and for how long. It is also highly probable that the customers that benefiting from the project early on during the asset's useful life will change over time as the topography of the transmission system continues to evolve.

Under the Midwest ISO's tariff construct, Attachments FF and GG coupled with Schedule 26 are used to allocate the costs of RECB projects to the transmission customers responsible for these costs. In summary, Attachment FF codifies the cost allocation criteria resulting from the RECB process as described above in order to parse out the MTEP 06 costs from Appendix A, which are subject to the RECB cost sharing, to the appropriate transmission customers within the various pricing zones throughout the Midwest ISO region. Attachment GG is used to calculate the fixed carrying charge for each transmission owner or independent transmission company within the Midwest ISO owning and constructing transmission assets under the MTEP 06 which are subject to the RECB cost sharing provisions. The fixed carrying charge is multiplied times the project cost to determine the total revenue requirement to be collected from transmission customers, consistent with the allocation percentages on a per project basis according to Attachment FF. The revenue requirements allocated to each pricing are collected under Schedule 26 and these revenue requirements are netted against the annual revenue requirements calculated under Attachment O of the Midwest ISO tariff in order to avoid double recovery. Transmission customers pay under

Schedule 26 using the same billing determinants used to determine their charges for transmission service under Midwest ISO's Schedules 7, 8 and 9.

VIII. JOINT DISPATCH

Q. WHAT ARE THE COST ADVANTAGES ASSOCIATED WITH A CENTRALIZED DISPATCH OF GENERATION ON A REGIONALIZED BASIS?

A. The major cost advantage associated with market mechanisms utilizing a single centralized regional dispatch is that a centralized dispatch enhances the ability for utilities to serve customers at the lowest cost in a manner consistent with maintaining reliable system operation. Through a single coordinated regional economic dispatch, similar to that employed by the Midwest ISO, PJM and the other northeastern markets, the RTO is able to arrange a more efficient (i.e., lower cost) dispatch for the broader region, as a whole, than can be achieved by continuing to utilize the individual dispatches (i.e. separate utility merit order stacking of resources) of the separate balancing authorities. A more efficient centralized regional dispatch, based on the offers and bids submitted by market participants, can then serve loads that are relying on the regional dispatch at the lowest cost. Regions currently served by low-cost resources will be able to continue to serve local loads at low cost, but any surplus low-cost resources available can be offered to the market and made available as part of the centralized regional dispatch which helps to displace higher costing generation resources and as such lowers the dispatch costs for other load within the region.

This allows the party owning the more competitive generation to obtain a return on the surplus low-cost resource that would have otherwise been left out of the dispatch solution if it were still part of an individual balancing authority's inefficient dispatch.

In those instances where an area of the RTO is short on generation and relies on imports to serve local loads, the centralized dispatch as a function of the market will facilitate the region's ability to be serve customers at lowest cost, either through purchases from a financially binding day-ahead energy market, real-time spot markets or through efficient scheduling of bilateral transactions between suppliers and load-serving entities. One other point, is the that LMP-based markets tend to support these transactions with effective and efficiently priced redispatch.

IX. CONCLUSION

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM YOUR TESTIMONY?

A. The decision point regarding RTO membership for KCPL and Aquila's electric utility assets after the merger is not a trivial issue and would have an impact on their costs on a going forward basis. Throughout the course of my testimony, I have summarized the principal cost and charge types that differ significantly between SPP and the Midwest ISO. There are vast differences between the basic functions of their energy markets. The Midwest ISO operates a Day-Ahead, Real-Time and FTR Energy Market that is certainly more complex than the SPP

Energy Imbalance Market. The mechanisms used to recover the respective RTO's administrative costs are different as the Midwest ISO collects its administrative costs using three different rate schedules, each with their own separate rate design, while SPP collects all of their administrative costs under a single rate schedule. While both RTOs have the potential exposure to energy market charges that are uplifted to load, such as Revenue Neutrality Uplift ("RNU"), as part of their market design there are many discernable differences between the makeup of these two charges. The Midwest ISO's recent issues with regard to the Revenue Sufficiency Guarantee charge further illuminate the differences between the RTOs with respect to costs potentially uplifted to load. The procurement of ancillary services is currently an area where the two RTOs are structurally similar in part (although the actual level of charges will still differ), but the Midwest ISO's recent ASM filing will create another point of departure once this market in implemented. The economic impact of rate pancaking for transactions between the various RTOs could be assessed if the merged company were to commit their facilities to one RTO or another. This would be of interest to the City of Independence if they were to elect to sell some of their energy from Iatan 2 to load in adjacent RTO once this generating plant becomes operational. Both the Midwest ISO and SPP have extensive plans for building additional regional transmission infrastructure, and the level and allocation of those costs will have differing impacts. Finally, my testimony described the economic and reliability differences resulting from joint dispatch.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Joint Application of Great Plains Energy Inc., Kansas City Power & Light Company, and Aquila, Inc. for Approval of the Merger of Aquila, Inc. with a Subsidiary of Great Plains Energy Inc. and for Other Related Relief	)))))))	Case No. EM-2007-0374

AFFIDAVIT OF MARK J. VOLPE

STATE OF INDIANA)

COUNTY OF HAMILTON)

Mark J. Volpe, being first duly sworn on his oath, states:

1. My name is Mark J. Volpe. I am a consultant with the law firm of Jennings, Strouss and Salmon PLC. My business address is 1700 Pennsylvania Avenue N.W., Suite 500, Washington, D.C., 20006 and my office address is 5898 Garden Gate Way, Carmel, Indiana 46033. My business telephone number is (317) 246-0933.

2. I certify that the foregoing Testimony was prepared by me or under my direct supervision and that such Testimony is true and correct to the best of my knowledge and belief.

MJVolpe
Mark J. Volpe

Subscribed to and sworn to me this 11th day of October 2007.

Ima L. Hicks
Notary Public

My Commission expires: 1/14/2011

Ima L. Hicks
Notary Public, District of Columbia
My Commission Expires 01/14/2011

DATA REQUEST– Set Independence_20070920
Case: EM-2007-0374
Date of Response: 09/28/2007
Information Provided By:
Requested by: Robbins Alan

Question No. : 2-8
Please state whether or not KCP&L intends to remain a member of Southwest Power Pool ("SPP") should Applicants' merger application be accepted. If no decision has been made on this issue, please explain why not.

Response:

KCPL intends to remain a member of the SPP RTO when the merger is completed.

Prepared by: Todd Fridley, KCPL - Transmission Services

DATA REQUEST– Set Independence_20070920
Case: EM-2007-0374
Date of Response: 09/28/2007
Information Provided By:
Requested by: Robbins Alan

Question No. : 2-9
Please clarify whether Aquila, Inc. will become a member of SPP or the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") following the merger. If no decision has been made regarding Aquila's RTO participation, please explain why not.

Response:

AQUILA RESPONSE:

Aquila has filed with the Missouri Public Service Commission, in Docket EO-2008-0046, for approval to become a member of MISO.

ATTACHMENTS: None

ANSWERED BY: Dennis Odell

DATE ANSWERED: September 26, 2007

Please refer to the Aquila response.

Prepared by: Todd Fridley, KCPL – Transmission Services