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Ellen Wolfe
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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

PREPARED JOINT TESTIMONY OF
RALPH L. LUCIANI
VICE PRESIDENT, CRA INTERNATIONAL

AND

ELLEN WOLFE
SENIOR CONSULTANT, CRA INTERNATIONAL

ON BEHALF OF SOUTHWEST POWER POOL, INC.

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your names, positions, and business addresses.

A. Our names are Ellen Wolfe, Senior Consultant, CRA International (CRA), 5925 Granite Lake Drive, Suite 120, Granite Bay, CA 95746 and Ralph L. Luciani, Vice President, CRA International, 1201 F Street, NW, Suite 700, Washington, DC 20004. CRA's name was changed from Charles River Associates to CRA International on May 6, 2005.

Q. What is the purpose of your joint testimony?

A. We will summarize the methodology and findings in the Southwest Power Pool (SPP) Cost-Benefit Analysis study (Report) performed by CRA for the SPP Regional State Committee (RSC). The study was published on April 23, 2005 and presented by CRA to the RSC on April 25, 2005. The study was subsequently revised on July 27, 2005. The study was requested by the RSC to assess the impact of alternative future roles of SPP in light of its approval as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC). In particular, we will describe the history and purpose of the study, discuss the study methodology and assumptions that were used, describe the study results with respect to specific costs and benefits, discuss other qualitative considerations evaluated in the study, and provide a comparison of the general framework of this study in comparison with other RTO cost-benefit studies.

Q. **What are CRA's qualifications and experience in performing cost-benefit studies of RTOs?**

A. CRA is comprised of over 500 professional staff. Our experts possess substantial electricity and gas industry knowledge and routinely provide clients with advice related to market economics, asset valuation, regulation, litigation, business strategy, public policy and market design. The CRA senior staff members that prepared this study have extensive experience in advising clients on institutional designs needed to effectively implement competitive electricity markets, and have performed a number of RTO cost-benefit studies. These include cost-benefit studies on behalf of RTO West in March 2002, on behalf of the Southeastern Association of Regulatory Utility Commission (SEARUC) in November 2002, on behalf of Dominion Power in June 2003, and on behalf of the Electric Reliability Council of Texas (ERCOT) in November 2004. In each of these studies, CRA has made use of its extensive knowledge of regional generation and transmission systems and electricity market structures and rules to specify a model representation of the regional electricity market. The computer simulation market model was used to project generation dispatch, production costs, inter-regional flows, and spot prices under various RTO-related scenarios. The results of the electricity modeling, supplemented with relevant RTO operating cost estimates, were then used to evaluate net benefits to individual regions and companies.

Q. **Please describe your roles in the preparation of the study.**

A. Ms. Wolfe was project manager of the study, and Mr. Luciani oversaw the financial evaluation of costs and benefits contained in the study. Both Ms. Wolfe and Mr. Luciani participated actively in the study from its inception in July 2004 through the writing of the report and presentation of the study to the RSC in April

2005. The CRA senior staff on this study also included Aleksandr Rudkevich, an expert on electricity market modeling, and J. Stephen Henderson, an expert on electricity policy and market power.

Q. **Please describe your educational and professional backgrounds.**

A. Ms. Wolfe has nearly 20 years of experience with electric utilities and in the energy industry, focusing on such issues as market designs and protocols, energy price forecasting and policy support. Ms. Wolfe previously led the RTO West and ERCOT cost-benefit studies. Ms. Wolfe has a B.S. in Electrical Engineering from the University of California, Davis, and Masters' degrees in Management and in Technology and Policy from the Massachusetts Institute of Technology.

Mr. Luciani has more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, and utility wholesale power solicitations. Mr. Luciani oversaw the financial and rate analyses presented in the SEARUC and Dominion Power RTO cost-benefit studies. Mr. Luciani has a B.S. in Electrical Engineering and Economics and a M.S. in Industrial Administration from Carnegie Mellon University.

2. HISTORY AND PURPOSE OF STUDY

Q. **What was the purpose of the study?**

A. The purpose of the study was to evaluate: (1) the costs and benefits that accrue from SPP-wide consolidated services and functions (which include reliability coordination and regional tariff administration) and (2) the costs and benefits of SPP's implementation of an Energy Imbalance Service (EIS) market.

Q. Describe the process used in preparing the study.

A. The study was performed under the direction of the RSC through the Cost Benefit Task Force ("CBTF"). The CBTF included representatives from the State Commissions in the SPP RSC, the SPP utilities, a consumer advocate, and SPP staff. After CRA's selection by the RSC in July 2004, an open, collaborative process was put in place by CRA and the CBTF in which stakeholders were presented multiple opportunities to review and comment on the proposed study methodology, input assumptions,[1] and interim results. Numerous conference calls and face-to-face meetings were held with CRA and CBTF members from July 2004 through April 2005. While stakeholders participated throughout the study process, the final study reflects the independent analyses, findings and judgment of CRA.

3. STUDY METHODOLOGY

Q. Please describe the general methodology applied in the study.

A. Five areas of analysis were selected and designed to provide a comprehensive understanding of the costs and benefits relevant to the SPP study questions.

a) Wholesale Energy Modeling

b) Allocation of Energy Market Impacts and Cost Impacts

c) Qualitative Assessment of Energy Imbalance Impacts

[1] To perform the market modeling in the study, it was necessary to finalize or "freeze" the market model input assumptions as of August 2004.

d) Qualitative Assessment of Market Power Impacts

e) Aquila Sensitivity Cases

The Wholesale Energy Modeling addressed the expected impacts on the SPP energy market resulting from the different operational or system configuration assumptions in the various cases. This energy market simulation, using General Electric's Multi Area Production Simulation Software (MAPS) tool, included an assessment of the impact on production costs, on the dispatch of the system, and on the interregional flows in the study area. The Wholesale Energy Modeling provided the energy market impacts for the analysis of the Allocation of the Energy Market Impacts and Cost Impacts. The Allocation of Energy Market Impacts and Cost Impacts provided an assessment of the cost and energy market impacts on SPP and individual market participants. This assessment was based on specific assumptions regarding regulatory policies and the sharing of trade benefits and was used to provide detailed company- and state-specific impact measures. A qualitative review of relevant issues that were not quantified was also performed, along with a special sensitivity in which Aquila was assumed to join the SPP EIS market.

Q. What scenarios were modeled in the study?

A. CRA modeled three operational market scenarios in this study in order to compare several potential future operating states:

- **Base case:** SPP within its current footprint with no balancing market
- **EIS case:** A real-time EIS market is implemented within today's SPP tariff footprint

- **Stand-Alone case:** SPP tariff is abandoned and each transmission operator operates under its own transmission tariff

Q. What time period was evaluated in the study?

A. The time horizon for the study consisted of the calendar years 2006–2015. A 10-year period is often used for studies of this type in order to capture both near-term and longer-term impacts. For the MAPS modeling, detailed simulations were performed for 2006, 2010, and 2014, and interpolation and extrapolation were used to obtain results for the other years in the study horizon. The Aquila Sensitivity cases were evaluated only for the year 2006 and only the wholesale market impacts were assessed in the Report.

4. WHOLESALE ENERGY MODELING

Q. Please describe the general framework applied in the wholesale energy modeling.

A. For each simulation year, MAPS modeling was performed for each of the three scenarios, and the results were compared to produce the Wholesale Energy impacts. Thus, the impacts of SPP returning to a non-RTO structure were determined by comparing the Stand-Alone case with the Base case, and the impacts of the EIS market were determined by comparing the EIS case with the Base case. The quantitative modeling of the three scenarios was distinguished by three factors: through-and-out rates for transmission service, the dispatch of non-network generating units, and the transfer limits on constraints within SPP.

Section 3 of the Report describes the Wholesale Energy Modeling, and Section 3.1.2 specifically defines the simulation cases.

Q. Can you discuss further what the Base case is meant to represent?

A. The Base case was developed to be a representative simulation of the current SPP wheeling tariff structure, transmission allocation practices, and transmission path management approaches. In this sense, although not necessarily fully capturing all current bilateral arrangements and practices, it is designed to simulate the "status quo" SPP operations and practices.

Q. Please describe the differences between the Stand-Alone case and the Base case simulations.

A. The Stand-Alone case simulation models instituted wheeling out and wheeling through charges between control areas *within* SPP. In the existing structure, represented by the Base case, wheeling charges were not applied between SPP control areas.

Q. Please describe the differences between the EIS case and the Base case simulations.

A. There are two differences, both of which reflect inefficiencies in the existing Base case market structure which are expected to be alleviated in the EIS market. First, in the current market structure, the scheduling capacity of major transmission paths (flowgates) is reduced given that SPP does not have full dispatch control of resources needed to manage the flows of energy throughout SPP. In the EIS case, SPP will centrally dispatch units and there is expected to be sufficient control and visibility to fully schedule the flowgates. The flowgate capacity is 10% lower in the Base case than in the EIS case based on historical flowgate flows during congestion events.

The second difference is the optimality of the dispatch of the system. Under the current market structure (Base case), some generating units, primarily certain merchants units in SPP, do not have network service and only obtain transmission service when there is available capacity. Under the EIS market, all units will have access to provide energy in the EIS market. In the Base case, the non-network units were only dispatched if there was spare transmission capacity. The list of non-network units treated in these cases was developed under consultation with the CBTF.

Q. What were the key inputs used in the wholesale energy modeling?

A. There are a large number of input variables to the wholesale energy models, and these assumptions were developed in conjunction with, or reviewed by the CBTF and SPP staff. The assumptions are described in detail in the Report Appendices 3-1 and 3-2. Key assumptions include the following:

- Hourly loads based on FERC 714 filings for 2002
- Gas and oil price forecasts developed by CRA
- Generation bids based on marginal cost[2] (fuel, non-fuel variable operations and maintenance, and opportunity cost of tradable emissions permits based on a number of public and private sources of information, as described in the Report Appendix 3-1) and an efficient dispatch based on these bids[3]

[2] Generating costs used in the simulated dispatch did not include any debt service, fixed O&M, or equity recovery in any of the cases' simulations.

[3] In general, the simulation models performed the economic dispatch of generating units as if all energy transactions occurred with a regional spot market. Individual bilateral transactions were not modeled

- Coal forecast as obtained from Resource Data International
- Use of a large “footprint” for the modeling, compiled by CRA, encompassing much of the Eastern Interconnect
- A transmission system configuration based on a load flow representation that includes all planned transmission upgrades, as provided by SPP
- Environmental adders based on forecast emissions values (based upon EPA’s Clean Air Markets database for 2002)
- New generation additions already under construction based on public information and validated with the CBTF.

5. COST AND BENEFIT MEASURES

Q. What measures of costs and benefits were used in the study?

A. Welfare for regulated customers of a utility, as measured in this study, was measured based on the charges to local area load for generation and transmission service, assuming that any benefits to the regulated utility are passed through to its native load. If these charges decrease, regulated customer welfare is assumed to increase. To quantify the change from Base case conditions to Stand-Alone status or participation in an EIS market, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation or production costs, energy purchases, wheeling charges, and O&M expenditures. The major categories of benefits and costs addressed in this study were trade benefits, wheeling charges and revenues,

explicitly, but rather were assumed to be efficient – given the simulation model parameters – such that the resulting dispatch would be equivalent to one that explicitly reflected bilateral transactions.

SPP implementation and operating costs, and individual utility implementation and operating costs.

Q. What were the sources of these cost and benefit measures?

A. Trade benefits and wheeling impacts were computed using the Wholesale Energy modeling results for each case. The changes in SPP costs from the Base to the Stand-Alone case and from the Base to the EIS case were estimated using projected SPP budgets. Individual company changes in operating and capital costs that would take place under stand-alone status and under participation in the EIS market were projected by each company, reviewed by CRA for consistency in approach, and converted to revenue requirements.

Q. Can you describe in further detail what trade benefits are and how they relate to the Wholesale Energy modeling results?

A. As described in Section 4, the cases analyzed in this study (Base, Stand-Alone, and EIS) reflect varying degrees of impediments to trade between regions. In particular, the institution of intra-SPP wheeling rates in the Stand-Alone case results in greater impediments to trade between utility areas, and institution of the EIS market results in reduced impediments to trade between utility areas. Reductions in the impediments to trading between utilities should generally result in a more efficient system dispatch and production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they are comprised of fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. While production cost changes cannot be used directly to allocate trade benefits to individual utility areas, the sum of all individual utility trade benefits will equal the total change in production cost.

6. STUDY RESULTS

Q. Please characterize the study results and how they should be interpreted.

A. The results reflect a number of inter-related analyses. As a result, individual elements of any particular analysis cannot be selectively changed without impacting the findings of the other analyses. The study results reflect our best prediction of future impacts, but are dependent on forecasts of uncertain input assumptions that may not unfold exactly as predicted. As will be discussed, the study results are subject to a margin of error, and the accuracy of the study results is higher at the regional level than it is for individual companies and states.

Q. Given the large number of inputs and the uncertainty in them, what provides any level of assurance that the results are meaningful?

A. There are a wide variety of assumptions used in the study, especially related to the wholesale energy modeling. However, because the wholesale energy impacts are measured as the difference between two cases, in many cases uncertainties in assumptions tend to operate similarly between cases and therefore tend to cancel out between cases. The majority of assumption uncertainties tend to operate in this fashion. It is only those few assumptions that tend to be sensitive to the market structure that likely could significantly influence the measured impacts. Assumptions such as these, to which the results may be sensitive, are discussed more specifically in the study.

6.1. Cost-benefit Results for EIS Market

Q. Please describe the cost-benefit results for the implementation of the EIS market.

A. The study found that the implementation of an EIS market within SPP would provide aggregate trade benefits of $614 million over the 10-year study period[4] to the transmission owners under the SPP tariff,[5] as summarized in Table 1. This

[4] All study period figures in this study are discounted present values as of January 1, 2006 over the 2006-2015 period. An annual discount rate of 10% was applied. Annual inflation was assumed to be 2.3% over the study period.

[5] Transmission owners under the SPP tariff include six investor-owned utilities (American Electric Power, Empire Electric Company, Kansas City Power & Light, Oklahoma Gas & Electric, Southwestern Public Service, and Westar Energy), two cooperatives (Midwest Energy and Western Farmers), one federal agency (Southwestern Power Administration), one state agency (Grand River Dam Authority) and one

represents about 2.5% of the total production costs within the SPP area during this period. The study accounted for impacts due to changes in wheeling charges and wheeling revenues, which was a minor consideration as shown in Table 1.

The study also evaluated the administrative costs of implementing the EIS market, both in terms of the costs incurred by SPP to administer the EIS market and of the costs to the utilities of participating in such a market. SPP's 10-year costs are shown in Table 1 as being $105 million, while the 10-year costs of the EIS market participants are estimated to be $108 million (increased costs are reported in the table as negative benefits so that all of the numbers in the table can be added directly). On net, the EIS market is estimated to provide considerably more benefits than costs, with the net benefits being $373 million to the transmission owners under the SPP tariff over the 10-year study period. In addition, the study estimated that benefits to other typical load-serving entities in the EIS market would be an additional $45.2 million without consideration of individual implementation costs.[6]

municipality (Springfield, Missouri). The Southwestern Power Administration has recently withdrawn from the SPP, but continues to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.

[6] These other entities are Arkansas Electric Cooperative Corporation; Oklahoma Municipal Power Authority; the Board of Public Utilities, Kansas City, Kansas; and City Power and Light, Independence, Missouri. Together with the transmission owners under the SPP tariff, these entities account for nearly all non-merchant generation in the EIS market. Other SPP members not modeled as participating in the EIS market in these results include Aquila, Cleco Power, Sunflower Electric, City of Lafayette, Louisiana, and Louisiana Energy & Power Authority.

Table 1 EIS Case, Benefits (Costs) by Category for Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	614.3
Transmission Wheeling Charges	24.4
Transmission Wheeling Revenues	(53.2)
SPP EIS Implementation Costs	(104.8)
Participant EIS Implementation Costs	(107.6)
Total	373.1

Q. How do the trade benefits of $614.3 million compare to the total production costs savings in the MAPS modeling?

A. The total production cost savings across the modeled footprint (most of the Eastern Interconnect) over the study period in the EIS case was $1,173 million. Thus, transmission owners under the SPP tariff obtain 52% of the total trade benefits. Including other SPP members that are not transmission owners but part of the EIS market, as well as SPP merchants and other SPP members bordering the EIS market, yields $813 million in trade benefits to SPP members, or roughly 70% of total production cost savings. Neighboring control areas that trade with SPP members obtain the remainder of the trade benefits.

Q. What were the estimated impacts of the EIS market on individual SPP utilities?

A. Table 2 shows the distribution among the individual utilities within SPP of these SPP-wide net benefits. As described in Section 4.1 of the Report, trade benefits were allocated among utilities within SPP, and control areas with direct interties to SPP, based on the change in utility generation in the EIS market case relative to the Base case. Individual utility wheeling impacts were assessed based on the change in the hourly MAPS net physical flows between utility control areas in the EIS market case relative to the Base case. The EIS market implementation costs incurred by SPP were allocated to individual companies using the standard company SPP assessment percentages applied in SPP budgets. The EIS market implementation costs incurred internally by each utility were estimated on a company-specific basis as described in Appendix 4-4 of the Report.

As shown in Table 2, most of the utilities are shown as receiving positive net benefits over the 10-year study period. Four of the utilities (KCPL, Midwest Energy, SWPA, and GRDA) have small impacts, either positive or negative, that should be interpreted as essentially breaking even. The results for these utilities are probably smaller than the margin of error of this study. Those utilities with larger positive impacts tend to be the companies that are measured in the EIS case to have a relatively significant change in the dispatch of their generating units under the institution of an EIS market.

Table 2 EIS Case, Benefits (Costs) for Individual Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	47.9
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	27.4
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

Q. Have you performed any updates to the allocation analysis since the time that the Report was originally published in April?

A. Yes. We discovered that the ownership shares for some jointly-owned generating units in SPP had been incorrectly input in the allocation model. Most were large coal-fired baseload plants that operate similarly in all scenarios and correcting the ownership shares would have only a minor impact on the individual company results. However, one of these jointly owned units, Stateline Combined Cycle, is a 500 MW gas-fired combined-cycle unit and has a significant change in its dispatch between the Base and EIS cases. The unit had been treated as 100% owned by Empire in the allocation model, and correcting the ownership shares to 60% for Empire and 40% for Westar Energy provides a material difference in the EIS market benefits allocable to Empire and Westar Energy. We corrected for the Stateline Combined Cycle ownership in the revised Report issued on July 27, 2005. The correction decreases the benefits for Empire and increases the benefits for Westar Energy from those originally presented in the Report in April. Table 2 above incorporates the figures from the revised Report.

Q. What is the margin of error in these results?

A. The study results are subject to a margin of error due to various abstractions that must be made in any modeling exercise such as this. Possible sources of error include incomplete monitoring of transmission constraints, incomplete data on generation characteristics, fuel price forecast margin of error, and error in forecasting RTO costs. CRA has not had the opportunity to develop a formal margin of error for this study, but CRA experience in modeling exercises of this type suggest that changes of less than $10 million over the study period for individual companies are likely to be within the study's margin of error.

Q. Can you discuss further the negative impacts shown for GRDA, KCPL and Midwest Energy?

A. Yes. Each of these companies shows trade benefits that exceed EIS implementation costs, but the resulting net benefits are offset by the wheeling impacts. While the net wheeling impacts on SPP as a whole are relatively small in the EIS case, the relative impact on certain individual companies is more significant. In the study, wheeling impacts were calculated based on hourly MAPS *net physical* flows between control areas, and as a practical matter this method cannot precisely represent the specific transactions that would actually pay wheeling charges, particularly in a highly interconnected compact region such as SPP. Further, some aspects that impact wheeling charges such as loop flow, "through" transactions that sink in adjoining SPP control areas, wheeling rate discounts, the bypassing of embedded control areas when scheduling through transactions, and the MW-mile methodology used to share SPP wheeling-out revenues were not precisely captured in this study.

Given the uncertainty associated with individual company wheeling impacts, the results excluding these wheeling impacts should also be considered in evaluating the specific net benefits to individual companies. Excluding transmission wheeling impacts, GRDA shows $4.1 million in benefits, KCPL shows $4.2 million in benefits, and Midwest Energy shows $0.1 million in benefits.

Q. What were the estimated impacts of the EIS market on individual states?

A. The estimated impact of the EIS market on the retail customers of the six investor-owned utilities (IOUs) in Table 2 is distributed to individual states in Table 3. This state-by-state allocation of benefits is based on a load-ratio share methodology and shows that the IOU retail customers in all states but Louisiana are measured to receive positive benefits, although the positive results for Arkansas and New Mexico are relatively modest. The Empire/Westar Energy unit ownership correction made in the revised Report increases the EIS market benefits shown for Kansas and decreases the benefits shown for Missouri from those originally presented in the Report in April. There were also some minor changes to the benefits of the other states in which Empire is located. Table 3 below incorporates the figures from the revised Report.

Table 3 EIS Market Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Arkansas	8.5
Louisiana	(3.8)
Kansas	26.4
Missouri	41.7
New Mexico	9.2
Oklahoma	141.1
Texas	26.6

Q. Can you discuss further the net benefits to Missouri?

A. Yes, the Missouri retail customer impacts shown in Table 3 are comprised of net benefits of $39.6 million for Empire and net benefits of $2.1 million for KCPL.[7] Excluding transmission wheeling impacts, as discussed above, would increase the net benefits for these Missouri companies. The net benefits to Missouri retail customers would be $41.4 million for Empire and $5.1 million for KCPL.

Q. How might you expect the net benefits to differ with higher natural gas price forecasts?

A. The EIS case benefits reflect, in part, the more efficient use of certain natural gas-fired merchant generating units. The more efficient use of these units produces production cost savings that create trade benefits. Give that in the EIS case these units tend to displace other less efficient units (such as gas-fired steam units), it is expected that higher natural gas price forecasts would lead to increased EIS case benefits.

[7] As discussed above, the overall net benefits for KCPL are negative $2.2 million when wheeling impacts are included. Based on guidance from KCPL, the KCPL trade benefits are allocated to individual wholesale and state retail jurisdictions using a net energy for load allocation, while the other categories of KCPL benefits and costs are allocated to individual jurisdictions using a four summer months coincident peak allocation. The resulting allocation of KCPL net benefits following this methodology yields a positive $2.1 million in net benefits for Missouri. See Appendix 4-2, Table 2 in the Report for further details.

Q. Can you comment generally on the level of accuracy in the regional results in comparison to the results at the company and state level?

A. Yes, as a general matter, any particular source of error in modeling (e.g., incomplete data on a particular unit or a particular transmission constraint) will have a greater relative impact on a localized area than on a broader region. Some sources of uncertainty in the study, such as the use of physical flows to estimate scheduled wheeling transactions, tend to offset one another when looking across a broader region. Similarly, the method used to allocate trade benefits to individual companies uses a level of aggregation that may not precisely capture the localized benefits of trading relative to the benefits of trading in other areas. Moreover, some uncertainties, such as the precise allocation of SPP wheeling-out revenues to individual companies, do not affect regional measures, but do provide additional uncertainty to company and state results.

6.2. Stand-Alone Cost-Benefit Results

Q. Please describe the cost-benefit results for the Stand-Alone case.

A. In the Stand-Alone case, implementation of intra-SPP wheeling rates leads to a less efficient dispatch and thereby increases system-wide production costs relative to the Base case. Table 4 shows that the trade benefits allocated to the transmission owners under the SPP tariff area is negative $21 million over the 10-year study period for this movement to a stand-alone structure. This is about 0.1% of the SPP production costs over this period. Wheeling rate impacts are shown in Table 4 as being somewhat positive, with a net impact of $16 million. The major costs associated with this case are the administrative costs that must be undertaken by the individual utilities if SPP were to no longer administer the SPP Tariff. In addition, the SPP withdrawal obligations are shown as an additional cost of $47 million.

These additional costs are offset to some degree by the reduction in FERC fees that would occur under a Stand-Alone scenario, assuming that FERC continues to assess its fees as it does at present. CRA has no way to assess whether such a revision in FERC's assessment formula is likely, but this benefit is subject to considerable regulatory uncertainty. So, while Table 4 indicates that the Stand-Alone case would result in about $70 million of additional net costs over the 10-year study period, this estimate could easily be closer to $100 million in net costs if FERC were to revise the formula for its fees.

Table 4 Stand-Alone Case, Benefits (Costs) by Category for Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Q. What were the estimated impacts of the Stand-alone case on individual SPP utilities?

A. Table 5 shows the distribution among the individual utilities within SPP of these SPP-wide net costs (negative net benefits). For the reasons discussed above, the results in Table 5 are shown without the impact of wheeling revenues and charges. As shown, excluding these wheeling impacts, the benefits of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).[8]

Table 5 Stand-Alone Case, Benefits (Costs) for Individual Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	**Type**	**Benefits excl. Wheeling**
AEP	IOU	(19.8)
Empire	IOU	(5.8)
KCPL	IOU	(17.8)
OGE	IOU	(8.2)
SPS	IOU	(5.0)
Westar Energy	IOU	(17.0)
Midwest Energy	Coop	(7.9)
Western Farmers	Coop	1.3
SWPA	Fed	1.2
GRDA	State	(4.8)
Springfield, MO	Muni	(2.5)
Total		(86.3)

In performing the distribution to individual utilities shown in Table 5, trade benefits were allocated using the same method described above for the EIS market case. The incremental costs incurred by individual utilities to provide the functions currently provided by SPP were estimated on a company-specific basis as described in Appendix 4-3 of the Report. FERC charge impacts and

[8] The individual company Stand-Alone results with wheeling impacts are provided in the study, but, as noted in the study, should be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts.

withdrawal obligations also were estimated on a company-specific basis as described in Section 4.2 of the Report.

Q. What were the estimated impacts of the Stand-alone case on individual states?

A. The estimated impact of the Stand-alone case on the retail customers of the six investor-owned utilities (IOUs) in Table 5 is distributed to individual states in Table 6. This state-by-state allocation of benefits is based on a load-ratio share methodology, and, as shown, the impact on most of the states is relatively modest.

Table 6 Stand-Alone Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

	Benefits excl. Wheeling
Arkansas	(3.0)
Louisiana	(2.6)
Kansas	(22.2)
Missouri	(13.7)
New Mexico	(0.7)
Oklahoma	(16.2)
Texas	(5.5)

Q. What were the estimated impacts of the Stand-Alone case on individual Missouri investor-owned utilities?

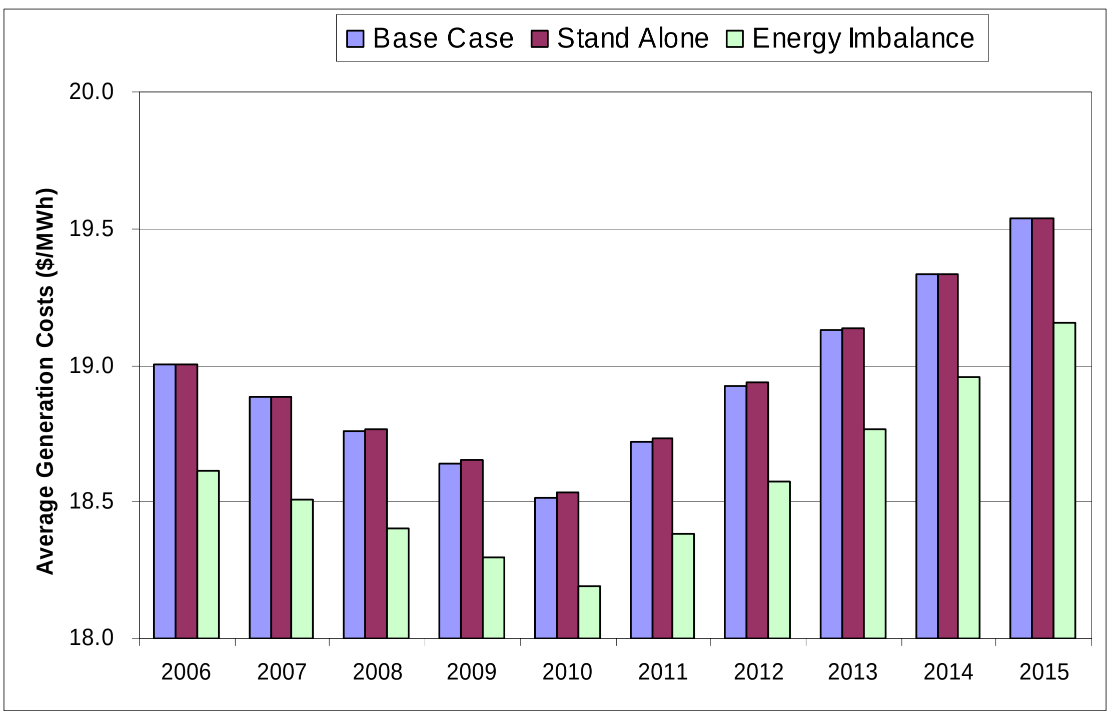
A. The Missouri retail customer impacts shown in Table 6 are comprised of increased costs of $4.8 million for Empire and $8.9 million for KCPL.

6.3 Wholesale Impacts to SPP

Q. Please describe the wholesale energy market impacts evaluated in the study.

A. The Wholesale Energy Modeling process provided the energy-impact inputs to the allocated results discussed above. It also yields some high-level, region-wide wholesale market metrics related to the three cases simulated. Figure 1 shows the SPP average annual generation cost impacts resulting from the cases. (Note that the trend across the years is primarily due to non-case related factors such as fuel prices, transmission system upgrades, and load growth.) The difference between the respective average cost in each year reflects the fact that the institution of the EIS market increases dispatch efficiency (reduces generation, or production, cost[9]) by approximately 2% ($0.32 to $0.39 per MWh).

Figure 1 Wholesale Aggregate Generation Cost Impacts



SPP spot energy prices are also expected to decrease by approximately 7%. The Stand-Alone comparison with the Base case did not reveal significant differences.

[9] Generation costs, or production costs include start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

These results are consistent with the level of SPP-wide trade benefits discussed above in the individual case findings.

6.4 Qualitative Analysis of EIS Impacts

Q. Please describe the qualitative considerations evaluated in the study.

A. In addition to the quantified impacts discussed above, the long-run impacts of implementing a formal nodal EIS market are expected to include improved transparency and improved price signals. Added complexities may produce adverse impacts during a transition period of roughly three to five years. Applying explicit imbalance energy prices creates risks for market participants associated with not following schedules; however, these risks are likely to abate as participants become familiar with the EIS market and are offset by the improved efficiency in scheduling that will result from the EIS market price signals. The movement with the EIS to the centralized management of inadvertent energy will likely be subject to additional production efficiencies, a benefit that is not captured in the quantitative results of the energy modeling. That is, with SPP operating the real-time balancing service, SPP will have greater visibility into the region than individual control area operators have now or would have going forward absent a regional Energy-Imbalance Service. SPP will also likely have improved schedule information and can better anticipate what otherwise would have been loop flows between adjacent control areas.

6.5 Market Power Considerations

Q. Please describe the market power considerations evaluated in the study.

A. CRA did not conduct a formal study of market power in conjunction with this cost-benefit study. Two primary factors, of approximately equal strength, suggest that market power is not likely to become a significant consideration under the EIS market, in particular. These are (1) the provision for an ongoing market monitoring function within SPP and for a separate, independent monitor, and (2) the lack of incentive for the exercise of market power under the economic conditions likely to prevail under the EIS market. Market monitoring is required by FERC and should provide a substantial check on any potential to exercise market power after the implementation of the EIS market. The continuation of cost-based regulation for most of the output of generation in this region means that the EIS market is not likely to augment the incentive to exercise market power in a significant way.

6.6 Aquila Sensitivity Case Results

Q. Please describe the wholesale market results of the Aquila in SPP sensitivity.

A. Using the Wholesale Energy Modeling sensitivity analysis performed for Aquila for 2006, CRA considered both (1) the wholesale market effects of whether Aquila was part of the MISO or whether Aquila was part of SPP, and (2) the sensitivity of the EIS wholesale market results to which RTO that Aquila joins. That Aquila wholesale market sensitivity simulation showed that if Aquila were to affiliate with SPP there would be wholesale market benefits to Aquila, though impacts to the surrounding SPP region was not necessarily affected in the same direction. That analysis suggested that while the SPP region's generating costs would be lower with Aquila in MISO, Aquila's generating costs would be lower with Aquila in SPP. The sensitivity analysis indicated that the wholesale market measures for the EIS market are not particularly sensitive to whether Aquila is in MISO or in SPP.

7. COMPARISON TO OTHER COST BENEFIT STUDIES

Q. How does the SPP Cost Benefit study compare to other RTO cost-benefit studies that have been performed?

A. Appendix 2-1 of the Report describes a number of RTO cost-benefit studies that have been performed since 2001, several of which were performed by CRA senior staff members. As the Report notes, each of these RTO cost-benefit studies differs in a number of important respects, addressing different policy questions and comparing market restructuring at various stages of integration. Of the studies, one – a study addressing the historical benefits of PJM – was based on historical evidence. The other studies included simulations and most used the same MAPS modeling application that was employed in the SPP study.

The studies have primarily addressed the benefits of RTO formation, although one of the studies, performed in 2004 for ERCOT addressed a nodal versus a zonal market structure, with the RTO in operation in both cases. Like the SPP study, the SEARUC study prepared by CRA also performed an allocation of trade benefits to determine impacts to native load, but performed the allocation to larger regions than the control areas used in the SPP study. Table 1 of the Report Appendix 2-1 provides a detailed comparison of study characteristics.

Q. Can you describe further how the SPP Cost Benefit study compares to the SEARUC cost-benefit study performed by CRA?

A. Yes, the SEARUC study focused in part on an assessment of the timing and regulatory treatment of the transmission integration costs needed to fully integrate the significant amount of merchant generating capacity that had been constructed in the Entergy and Southern Company regions. The SPP region is not faced with transmission integration cost issues of a similar magnitude, and thus this issue was not a focus of the SPP study.

Absent this transmission integration issue, the SEARUC study found 10-year benefits for the institution of a SeTrans RTO with a locational marginal pricing market of $352 million. However, the benefits to the GridSouth and GridFlorida RTOs were found to be negative. In considering these results, it is important to understand that the SEARUC study analyzed a transition from a “No RTO” base case in which local load-serving utilities were essentially in a stand-alone status, and not participating in the regional joint functions already in place at SPP (e.g., tariff administration, reliability coordination, available transmission capacity calculations). Thus, the incremental costs to move to an EIS market relative to the Base case for SPP were substantially less than those estimated for the SEARUC RTOs to start-up, implement and operate an RTO from base stand-alone conditions.

For example, the 10-year RTO implementation and operation costs projected in the SEARUC study ranged from $543 to $693 million for the SeTrans RTO and from $501 to $632 million each for GridSouth and Grid Florida. This compares to the projected $212 million in 10-year EIS implementation and operation costs for SPP (including both SPP and member utility costs). On a $/MWh of load basis, the SPP EIS costs were roughly equal to the SeTrans RTO costs, but about half that of GridSouth and GridFlorida (which are more comparable in terms of load served to the SPP EIS market).

8. CONCLUSIONS

Q. Please summarize your conclusions.

A. The study found that the implementation of an EIS market within SPP would provide nearly $400 million in benefits to the Transmission Owners under the SPP tariff. The benefits to other EIS market members and to regions bordering the SPP EIS market are also significant. While there are substantial costs that will be incurred by SPP and by EIS participants in implementing and administering the EIS market, the projected regional benefits significantly exceed these projected costs. With respect to Missouri, the collective benefit of the EIS market to the Missouri retail ratepayers of Empire and KCPL are substantially positive.

Q. Does this conclude your joint testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	)))))	Case No. EO-2006-0142

AFFIDAVIT OF ELLEN WOLFE

State of CALIFORNIA)
) ss
County of PLACER)

Ellen Wolfe, being first duly sworn on his oath, states:

1. My name is Ellen Wolfe. I am Senior Consultant, CRA International (CRA), 5925 Granite Lake Drive, Suite 120, Granite Bay, CA 95746

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, prepared as joint testimony with Ralph L. Luciani, Vice President, CRA International, 1201 F Street, NW, Suite 700, Washington, DC 20004, on behalf of Southwest Power Pool, Inc., consisting of twenty-nine (29) pages, having been prepared in written form for introduction into evidence in the above-captioned case.

3. In consultation with Ralph L. Luciani, I have knowledge of the matters set forth therein. I hereby swear and affirm that the answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Ellen Wolfe

Ellen Wolfe

Subscribed and sworn before me this 29th day of September 2005.

EILEENE M. SCHLICHTING
COMM. # 1540381
NOTARY PUBLIC-CALIFORNIA
PLACER COUNTY
COMM. EXP. JAN. 1, 2009
MGC1

Eileene M. Schlichting

Notary Public

My commission expires: Jan. 1, 2009

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	)))))	Case No. EO-2006-0142

AFFIDAVIT OF RALPH L. LUCIANI

State of ______________)
) ss
County of _____________)

Ralph L. Luciani, being first duly sworn on his oath, states:

1. My name is Ralph L. Luciani, Vice President, CRA International, 1201 F Street, NW, Suite 700, Washington, DC 20004.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, prepared as joint testimony with Ellen Wolfe, Senior Consultant, CRA International (CRA), 5925 Granite Lake Drive, Suite 120, Granite Bay, CA 95746, on behalf of Southwest Power Pool, Inc., consisting of twenty-nine (29) pages, having been prepared in written form for introduction into evidence in the above-captioned case.

3. In consultation with Ellen Wolfe, I have knowledge of the matters set forth therein. I hereby swear and affirm that the answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Ralph L. Luciani

Ralph L. Luciani

Subscribed and sworn before me this 28th day of September 2005.

Notary Public

My commission expires: 1/1/2008

Karyn Joelle Walz
Notary Public, District of Columbia
My Commission Expires 1-1-2008