BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S INTERIM REPORT ON ITS PARTICIPATION IN THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION,	)	**Case No. 13-00______-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY	)	
Respondent.	)	

DIRECT TESTIMONY

of

William A. Grant

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

February 4, 2013

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
AGC	Automatic Generation Control
ARR	Auction Revenue Rights
BA	Balancing Authority
CAT	Curtailment Adjustment Tool
CAWG	Cost Allocation Working Group
CBS	Cost Benefit Study
CCN	Certificate of Convenience and Necessity
CBS	Cost Benefit Study
Commission	New Mexico Public Regulation Commission
DA	Day Ahead
DTO	Designated Transmission Owner
EIS	Energy Imbalance Service
ERCOT	Electric Reliability Council of Texas
EPAct	Energy Policy Act of 2005
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause
ICT	Independent Coordinator of Transmission
IDC	Interchange Distribution Calculator

Acronym/Defined Term	**Meaning**
IM	Integrated Marketplace
Interim Period	February 3, 2010 – February 2, 2015
IPP	Independent Power Producer
ITP	Integrated Transmission Planning
ITPNT	ITP Near Term
ISO	Independent System Operator
ITO	Independent Transmission Organization
Lamar DC Tie	Lamar Tie Line
LIP	Locational Imbalance Price
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
MOPC	Market and Operations Policy Committee
MP	Market Participant
NERC	North American Electric Reliability Corporation (successor to the North American Electric Reliability Council)
Network	Network Integration Transmission Service
NITSA	Network Integration Transmission Service Agreement
NTC	Notice to Construct
OATT	Open Access Transmission Tariff
PSCo	Public Service Company of Colorado, a Colorado corporation

Acronym/Defined Term	**Meaning**
PTP	Point-to-Point transmission service
PUCT	Public Utility Commission of Texas
RC	Reliability Coordinator
RE	Regional Entity
RRO	Regional Reliability Organization
RSC	Regional State Committee
RTO	Regional Transmission Organization
RTOSS	RTO Scheduling System
RUC	Reliability Unit Commitment
SPP	Southwest Power Pool, Inc.
SPP Regional OATT	SPP Open Access Transmission Tariff as accepted by the FERC
SPS	Southwestern Public Service Company, a New Mexico corporation
STEP	SPP Transmission Expansion Plan
TCR	Transmission Congestion Right
TLR	NERC Transmission Loading Relief
TO	Transmission Owner
TOP	Transmission Operator
TWG	Transmission Working Group
WECC	Western Electricity Coordinating Council
Xcel Energy	Xcel Energy Inc.

Acronym/Defined Term	**Meaning**
XES	Xcel Energy Services Inc.

LIST OF ATTACHMENTS

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William A. Grant. My business address is 600 South Tyler, Suite 2900, Amarillo, Texas 79101.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company ("SPS"), a New Mexico corporation and electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a registered holding company that owns several electric and natural gas utility operating companies.[1]

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

A. I am employed by SPS as Director, Strategic Planning.

Q. Please briefly outline your responsibilities as Director, Strategic Planning.

A. I am responsible for determining the appropriate planning strategy for SPS. In this role, I work with SPS's generation and transmission planning and operation personnel and coordinate with the Southwest Power Pool ("SPP") Regional

[1] Xcel Energy is the parent company of the following four wholly owned electric and gas utility operating companies: Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; Public Service Company of Colorado, a Colorado corporation ("PSCo"); and SPS (collectively, "Operating Companies"). Xcel Energy's natural gas pipeline subsidiary is WestGas Interstate, Inc.

Transmission Organization ("RTO") on regional policy and cost allocation issues affecting SPS.

Q. What is your professional experience?

A. I have 31 years of experience in both power plant and system operations at Xcel Energy or its predecessors. I have had responsibility for operating several different types of electric generating units ranging from diesel generators, coal-fired steam electric stations, and gas-fired steam units and combustion turbines. I have five years experience as a System Operator for the SPS transmission control center. For seven years, I was Director, Power Operations for Xcel Energy Services Inc. ("XES"), in which I was responsible for the economic dispatch and analytical support for all of the Xcel Energy Operating Companies, including SPS. For seven years, I was Manager, Transmission Control Center and Wind Integration for SPS. I recently was named Director, Strategic Planning for SPS.

Q. Have you testified before any regulatory commission?

A. Yes. I have testified before the New Mexico Public Regulation Commission ("Commission"), the Public Utility Commission of Texas ("PUCT"), the Colorado Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC").

II. ASSIGNMENT, SUMMARY OF RECOMMENDATIONS, AND ORGANIZATION OF TESTIMONY

Q. What is your assignment in this proceeding?

A. My testimony is part of SPS's Interim Report on its participation in the SPP. The Commission directed SPS to file the Interim Report in its February 2, 2012 Order in Case No. 07-00390 ("February 2nd Order") [2]. In my testimony, I provide:

- A summary of Case No. 07-00390-UT, including the Uncontested Stipulation ("Stipulation") approved by the Commission, the certification of the Stipulation ("Certification"), the February 2nd Order, and the requirement for SPS to file the Interim Report;
- A brief background of SPS and the SPP, and, SPS's membership in the SPP;
- An overview of the services provided by the SPP and a discussion of significant changes in the SPP since the February 2nd Order was issued;
- An assessment showing significant actual production costs benefits from SPS's participation in the SPP Energy Imbalance Service ("EIS") Market to an estimate of SPS energy costs absent SPS's participation in the EIS Market;

[2] *In the Matter of an Investigation into the Prudence of Southwestern Public Service Company's participation in the Southwest Power Pool Regional Transmission Organization*, Case No. 07-00390-UT, Final Order Approving Certification of Stipulation (February 2, 2010).

- An estimate showing expected future substantial production costs benefits resulting from SPS's participation in the EIS Market; and
- A discussion of other benefits that continue as a result from SPS's membership in the SPP.

Q. Are you the only witness presenting direct testimony for SPS?

A. No. Ruth M. Sakya also testifies on behalf of SPS. Ms. Sakya addresses: (1) SPS's costs and off-setting revenues associated with its participation in the SPP and how those costs and revenues are treated for ratemaking purposes; (2) the North American Electric Reliability Corporation ("NERC") fees SPS pays to the SPP; (3) the Commission's authority regarding the transmission-related and generation-related components of SPS's bundled New Mexico retail revenue requirement and the protection of SPS's New Mexico retail customers; and (4) certain reporting and notification requirements under the Stipulation.

Q. Please summarize the conclusions and recommendations in your testimony.

A. SPS's New Mexico Customers have benefitted greatly from SPS's participation in the SPP. The benefits result from the services SPP provides to SPS, which results in lower costs of providing service for SPS customers. As required by the February 2nd Order, SPS's analyses demonstrate that SPS's participation in the EIS Market has resulted in a reduction of actual production costs of approximately $19.28 million. Further, SPS estimates continual production cost savings of approximately $43.7 million through February 2015 as a result of EIS Market participation and other market activity.

In addition to participation in the EIS Market and the associated reduction in production costs, other benefits acknowledged in the February 2nd Order continue to exist for SPS's New Mexico customers as a result of the SPP membership, including:

- Membership in the SPP reserve sharing group, which results in an estimated annual savings of $80.9 million dollars from avoided start up and fuel costs and estimated annual savings of $32.96 million from reduced capacity margin.
- The SPP provision of security reliability coordination services to manage transmission congestion on a regional basis.
- The SPP acting as the NERC Regional Entity ("RE") to establish regional reliability standards.
- The SPP transmission planning functions, which ensures transmission expansion is performed on a regional, long-term basis to ensure continued reliability and economic upgrade implementation.
- The SPP's processing of wholesale generation interconnection requests and long-term transmission requests.
- A reduction in labor costs due to the services provided by the SPP.

Based on the continued significant benefits received by SPS's New Mexico customers as a result of the SPP membership, the Commission should approve SPS's membership in the SPP on a permanent basis.

Q. How is the remainder of your testimony organized?

A. In the next section of my testimony, I describe the February 2nd Order, the Stipulation and the Certification. In Section IV, I describe SPS. In Section V, I describe the SPP. Then in Section VI, I discuss in greater detail some of the services provided to SPS by the SPP. I also discuss the upcoming SPP Integrated Marketplace, how it will provide benefits, and the need to turn over the Balancing Authority responsibilities to the SPP.

In Section VII, I discuss the benefits of continued membership in the SPP, including the results of the production cost analysis, which shows a $19.28 million savings as a result of SPS's participation in the EIS Market since the February 2nd Order and an estimate of $43.7 million of production costs savings as a result of continued participation in the EIS Market through 2015. I further discuss other cost-saving benefits and qualitative benefits from continued SPP membership. In Section VIII, I provide an overview of other costs and burdens associated with the SPP membership, which will be more fully discussed by SPS

Witness Ms. Sakya. Finally, in Section IX, I set out SPS's requests to the Commission in this case.

III. BACKGROUND ON THE FEBRUARY 2ND ORDER AND THE STIPULATION IN CASE NO. 07-00390-UT

Q. Please provide an overview of the February 2nd Order.

A. In Case No. 07-00390-UT, the Commission considered whether SPS's membership in the SPP is beneficial to SPS's New Mexico retail ratepayers. In addition, the Commission considered SPS's request for approval to transfer retail load to the Network Integration Transmission Service Agreement ("NITSA") under the SPP Regional Open Access Transmission Tariff ("OATT").

In that case, SPS provided extensive testimony, evidence, and cost benefit analyses to demonstrate that the costs incurred by SPS to participate in the SPP would be greatly out-weighed by the beneficial impact on SPS's purchased power and fuel costs, other cost savings and reliability of service. In addition to the Commission's Utility Division Staff ("Staff") and the New Mexico Attorney General, a number of other parties intervened in the proceeding.

The parties negotiated over several months and reached the agreements reflected in the Stipulation. A copy of the Stipulation is provided as Attachment WAG-1. Among other items, the Stipulation provided: (1) approval of SPS's participation in the SPP RTO on an interim basis of five years; and (2) no opposition to the transfer of SPS's New Mexico retail load to network transmission service ("Network") under the SPP OATT's NITSA. The Hearing

Examiner issued his Certification on December 9, 2009, which the Commission approved in its February 2nd Order.

Q. Please describe the benefits of SPS's participation in the SPP as identified in the Certification.

A. The Certification identified a number ways in which SPS's participation in the SPP resulted in cost savings for SPS's New Mexico retail customers. A large portion of the benefits resulted from SPS's participation in the EIS Market, which is operated by the SPP. The EIS Market is a real-time balancing market using Locational Marginal Pricing ("LMP") and physical transmission rights. Through the EIS Market, the SPP models the least costly means of obtaining energy to serve the next increment of load based on the lowest LMP while maintaining reliability. SPS benefits by reducing the output of its own generation and purchasing lower cost energy from the EIS Market. SPS also offers its generation for sale into the EIS Market on an incremental basis. The Certification identified that from November 2007 through June 2008, SPS had experienced an average monthly benefit of approximately $252,000 through participation in the EIS Market.

In addition, other cost savings resulted from SPS's membership in the SPP contingency reserve sharing group. The Certification explained that the contingency reserve sharing agreement among SPP members allows each member to reduce the amount of contingency reserve it would otherwise be required to procure independently. SPS, for example, is required by NERC to carry sufficient reserves to respond to a sudden loss of capability equal to the SPS balancing area's most severe contingency, *e.g.*, an unplanned outage at the Tolk generation facility. Without the contingency reserve sharing agreement, SPS would have to carry 540 MW of contingency reserves, with half running, but not producing electricity. With the contingency reserve sharing agreement, SPS is only required to obtain 151 MW of contingency reserve to comply with NERC standards.

Finally, other cost savings were identified through the SPP providing transmission planning, and processing generator interconnection and transmission interconnection requests. In particular, without the SPP providing these services, SPS would need to hire additional engineers and incur the related labor expense.

Q. In addition to cost-saving benefits identified in the Certification, were other benefits identified?

A. Yes. The Certification noted reliability benefits from SPS's participation in the SPP. For example, the Certification identified the SPP's obligation to provide security reliability coordination services to manage transmission system congestion on a regional basis. In addition, the Certification identified that the

SPP is responsible for establishing regional reliability standards to ensure that all entities that could affect the reliability of the bulk electric system operate their facilities in a reliable manner.

Q. Please explain the Commission's interim approval of SPS's participation in the SPP.

A. The Commission approved SPS's participation in the SPP for an interim period of five years from the date of the February 2nd Order, that is, for the five-year period ending February 2, 2015 ("Interim Period"). Section 4 of the Stipulation requires SPS to file and serve on the other parties and Staff an Interim Report two years before the end of the Interim Period, that is, by February 2, 2013. As part of the Interim Report, SPS is required to provide a comparison of: (1) actual production costs from participation in the SPP EIS market to an estimate of SPS energy costs absent SPS's participation in the EIS Market; and (2) estimated production costs for participation in the EIS Market to an estimate of SPS energy costs absent participation in the EIS Market. In addition, SPS is allowed to provide other benefits and identify additional costs or other burdens related to SPS's continued participation in the SPP RTO.

Q. What happens if the Commission does not act on SPS's Interim Report by the end of the Interim Period, February 2, 2015?

A. Under Section 2 of the Stipulation, "[i]f the Commission does not issue an order to terminate or extend its interim approval prior to the end of the Interim Period, the approval of SPS's participation in the SPP and the transfer of SPS's retail load to the SPP Regional OATT shall no longer be deemed to be interim."

Q. Does the Stipulation establish reporting and notice requirements for SPS?

A. Yes. SPS is required to provide the Commission with: (1) notice if the SPP administrative charge increases by more then 25% above $0.19 per MWh and to explain the reasons for the increase; (2) notice of any material changes in the membership or load functions of the SPP within 60 days of such event; (3) annual reports regarding SPP-related charges for the prior calendar year; and (4) notice if SPS proposes to participate in any additional markets beyond the EIS Market or if the SPP proposes to modify the OATT to begin providing additional market services.

Q. Has SPS complied with these reporting and notice requirements?

A. Yes. SPS has filed the annual reports regarding SPP-related charges. In addition, SPS filed a notice regarding the administrative charge on February 13, 2012. Ms. Sakya provides copies of these filings as attachments to her testimony. There have been no other events that triggered these notice requirements.

The SPP, however, is planning to replace the EIS Market with a new market in 2014, the Integrated Marketplace. The SPP has already provided the Commission with notice of this additional market. SPS is providing its notice of that additional market through this Interim Report. I will discuss the Integrated Marketplace in more detail later in my testimony.

IV. DESCRIPTION OF SPS

Q. Please generally describe SPS.

A. SPS is a New Mexico corporation, with its corporate headquarters in Amarillo, Texas, and a vertically integrated electric utility that provides generation, transmission, and distribution services in Texas and New Mexico. SPS is subject to the jurisdiction of the Commission, the Public Utility Commission of Texas, and the FERC. SPS generates, transmits, distributes, and sells electric energy to approximately 376,000 customers in its 52,000 square mile service area of the Panhandle and the South Plains of Texas, and eastern and southern New Mexico. SPS's service area extends approximately 400 miles from north to south and 200 miles from east to west. A copy of the map of SPS's service territory is provided as Attachment WAG-2.

SPS sells power to retail customers and wholesale customers over its system. Approximately 36 percent of the load on the SPS system is wholesale sales or transmission-only load. SPS's service area is primarily agricultural, but it also has large areas of oil and natural gas production. In 2012, the generation system peak of SPS was 5174 MW, and annual electric sales were 27,818 GWh.

SPS has been a transmission-owning member of the SPP since 1973 and made its transmission facilities available for service under the SPP Regional

OATT in 2000. Although SPS operates adjacent to the Electric Reliability Council of Texas ("ERCOT") grid, it has no direct interconnections with ERCOT transmission owners.

Q. Please describe SPS's operations in New Mexico.

A. SPS sells electricity to approximately 100,000 retail customers in and around the communities of Artesia, Carlsbad, Clovis, Dexter, Eunice, Hagerman, Hobbs, Jal, Lake Arthur, Loving, Malaga, Monument, Otis, Portales, Roswell, Texico, Tucumcari, and White City under rates subject to the Commission's jurisdiction. The New Mexico service territory thus comprises approximately 31 percent of all SPS retail customers and approximately 17 percent of total 2012 electric sales.

V. DESCRIPTION OF THE SPP

Q. Please describe the SPP.

A. The SPP is a FERC-approved RTO. It is an Arkansas non-profit corporation with its principle place of business in Little Rock, Arkansas. SPP has 66 members, consisting of 14 investor-owned utilities, 11 municipal systems, 12 generation and transmission cooperatives, 4 state authorities, 8 independent power producers, 10 power marketers, and 7 independent transmission companies.

Q. Please describe the services the SPP provides to its members.

A. As an RTO, SPP provides several services to its members, consisting of:

- Reliability Coordination;
- Tariff Administration;
- Regional Scheduling;
- Transmission Expansion Planning;
- Market Operations;
- Compliance; and
- Training.

I provide a more detailed discussion of some of the services provided by the SPP later in my testimony.

Q. How does the SPP develop its policies, rules, and tariffs?

A. The SPP is a member-driven organization. As a result, various committees exist within SPP to develop policy, rules, and tariff provisions related to a wide variety of topics. The primary role of the SPP stakeholder committees and working groups is to drive major initiatives that improve or enhance SPP operations. The stakeholder process also focuses on planning for the future. The various committees and working groups provide recommendations to the SPP independent Board of Directors on technical issues. The committees are further comprised of working groups, steering committees, and task forces. The committees and groups are made up of representatives of the SPP members, including SPS. An organizational chart of SPP's committees and working groups is attached to my testimony as Attachment WAG-3.

Q. Please provide an explanation of SPP's committee and working group structure.

A. The SPP Board of Directors is the ultimate decision-maker for the SPP, but various sub-groups report directly to the Board. One group is the Market and Operations Policy Committee ("MOPC"). The MOPC has representatives from all SPP Members and is responsible for making recommendations to the Board of Directors involving market, policy, planning, and operational issues. I am the voting member of the MOPC for SPS. The proposals provided by MOPC reflect input and work of a number of sub-groups, including the Transmission Working Group ("TWG").

The TWG in turn is responsible for planning criteria to evaluate transmission additions, seasonal available transmission capacity calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. The TWG: (1) develops recommendations for the MOPC regarding changes to particular sections of SPP's Reliability Criteria; (2) works with individual transmission owners on issues of coordinated planning and NERC and SPP compliance; and (3) is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region.

Q. Do state retail rate regulators have a role in the SPP member-driven process?

A. Yes. State retail regulators in the SPP footprint have an active role through the Regional State Committee ("RSC").

Q. Please describe the RSC.

A. The RSC is comprised of retail regulators across the SPP footprint, and has its own working group, the Cost Allocation Working Group ("CAWG"), which is made up of staff members of the retail regulatory authorities. The SPP RSC actively engages in a broad range of issues where SPP has ceded authority, including transmission planning and cost allocation, resource adequacy, allocation of transmission rights, and market evolution issues. For example, the RSC determines: (1) the approach for resource adequacy across the entire region and, with respect to transmission planning; (2) whether transmission upgrades for remote resources will be included in the regional transmission planning process; and (3) the role of transmission owners in proposing transmission upgrades in the regional planning process. The SPP RSC may further direct SPP to submit FERC filings to effectuate regional changes proposed by the SPP RSC. Thus, the RSC is an active and important part of the SPP stakeholder process, providing collective retail regulatory agency input on matters of regional importance related to the development and operation of the bulk electric transmission system.

Q. Please describe the SPP Regional OATT and its impact on SPS.

A. The SPP offers transmission service under the SPP Regional OATT, which sets forth the wholesale transmission service rates for the SPS rate zone and the other rate zones (approximately 16) in the SPP region. All transmission service arrangements for SPS's wholesale customers are subject to the SPP Regional OATT. In addition, PSCo and the Municipal Energy Agency of Nebraska take Network service under the Xcel Energy OATT across the Lamar Tie Line

("Lamar DC Tie"), which went into service in May 2005, for loads on the PSCo system, limited to the capacity (210 MW) of the Lamar DC Tie.

Both the SPP Regional OATT and the Xcel Energy OATTs relate to the provision of transmission service in interstate commerce and are regulated by the FERC under the FPA and FERC Orders No. 888 (1996) and 890 (2007). The SPP Regional OATT allows access to transmission service to deliver generation anywhere in the SPP to load anywhere in the SPP at non-pancaked rates. By contrast, the SPS system provisions of the Xcel Energy OATT only allow access to the SPS transmission system and only for the grandfathered service that has been granted. All new transmission service is subject to the terms and condition of the SPP OATT.

The SPS wholesale merchant function purchases transmission service under the SPP Regional OATT to deliver wholesale sales to customers connected to the SPS transmission system, to make wholesale sales out of the SPS control area, or to deliver capacity or energy purchased from third party utilities. SPS serves its retail native load customers on a Network basis subject to the non-rate terms and conditions of the Xcel Energy OATT, but does not pay any transmission service rates for use of its own system. However, SPS must pay certain SPP Regional OATT charges for SPP services, such as the SPP

Administrative Fee imposed under Schedule 1A to the SPP Regional OATT, for all loads in the SPP region (including retail native loads).

Q. Describe further the relationship between the SPP and the Xcel Energy OATTs and the Lamar Tie.

A. The SPP OATT and the Xcel Energy OATT specify terms and conditions for transmission service in the SPS zone. Most of SPS's wheeling activity takes place under the SPP OATT. Since SPP filed its regional OATT, all new network transmission service and all point-to-point ("PTP") transmission service granted since 2000, except for grandfathered service across the Lamar DC Tie, have been provided under the SPP OATT for the SPS zone.

The Xcel Energy OATT is a joint transmission tariff, approved by the FERC, for all of Xcel Energy's Operating Companies. SPS's participation in the Xcel Energy OATT relates to transactions over the Lamar DC Tie. SPS purchases, and has historically provided, transmission service across the Lamar DC Tie under the Xcel Energy OATT.

VI. DESCRIPTION OF THE SERVICES PROVIDED THE SPP

A. *Reliability Coordination*

Q. Please discuss the SPP's reliability coordination function.

A. NERC Standards require every Regional Reliability Organization ("RRO"), subregion, or interregional coordinating group to establish a Reliability Coordinator to continually assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries. SPP is recognized as the Reliability Coordinator ("RC") for all of the Balancing Authorities ("BA") and Transmission Operators ("TO") in the SPP reliability footprint. The SPP Reliability Coordinator is responsible for the bulk transmission reliability and power supply reliability within its Reliability Coordination Area. Bulk transmission reliability functions include assessment of real-time, current day and next-day operating conditions, loading relief procedures, re-dispatch of generation, coordination of transmission and generation outages, and ordering curtailment of transactions and load. Power supply reliability entails monitoring Balancing Authority Area performance and ordering the Balancing Authorities to take actions, including load curtailment and adjusting generation levels in situations where an imbalance between generation and load places the system in jeopardy.

Q. Please describe further the activities the SPP undertakes to fulfill its reliability coordination function.

A. As both the RE and the RRO, the SPP monitors power flow throughout its regional footprint. The SPP anticipates problems and takes preemptive action to mitigate operating limit violations. The SPP coordinates regional response in emergency situations or blackouts. The SPP oversees SPS's operations under the FPA and FERC Order No. 693 regulations pertaining to mandatory reliability standards. SPP coordinates and approves transmission and generation outages and performs next day and real time studies to help identify potential overload and reliability issues. SPP sends outage data to the NERC interchange and distribution calculator to keep the models updated for purposes of evaluating transaction impact on overloaded transmission lines to provide transmission line loading relief.

Q. What is congestion management and how does it fall under the SPP reliability coordination function?

A. Congestion management is the process that RCs utilize to relieve transmission congestion on the bulk electric power system. Congestion is when the power flows on the system load to the point that an element has either reached its thermal loading rating, has reached a point that voltage stability can not be maintained, or the next event on the system will cause either a thermal or voltage stability violation. The two major processes utilized in relieving congestion is Transmission Load Relief ("TLR") or redispatch of generation. The SPP RC is responsible for issuing the necessary level of TLR to relieve congestion on the transmission system. SPP through the stakeholder process will identify elements on the system that are identified as flowgates that will be monitored and entered into the NERC Interchange Distribution Calculator ("IDC") that is used to identify transactions that impact the flowgate for purposes of providing relief by curtailing these transactions. Before the SPP EIS Market started in 2007, this was the primary way that relief was provided on the SPP transmission system. For SPS to get relief on a transmission facility, the SPS transmission operator would call the SPP RC and ask for the implementation of a TLR and transactions that were identified through the NERC IDC as having a greater than 5% impact on the element would be curtailed. SPP still utilizes the TLR process for transactions into and out of the SPP footprint but developed a Curtailment Adjustment Tool ("CAT") for transactions that source and sink within the SPP footprint. CAT will utilize generation redispatch with generation that is participating in the EIS Market to provide relief for the congested element if available. The monitored flowgates are in the SPP market model and the market will perform a constrained economic dispatch to keep the flows on the monitored elements within compliance. This will allow flows that in the past would have been curtailed. If generation dispatch is not available to provide relief, then the SPP would utilize the TLR process if necessary to provide the relief.

Q. What is outage coordination and how does it fall under the SPP reliability coordination function?

A. The SPS transmission operator will determine when there is a need to take a transmission line out of service. The reasons for needing a transmission line out of service can vary from repairs of existing lines to new construction to unplanned outages. For planned outages on the bulk electric system for line outages, the SPP RC as well as the SPS transmission operator ("TOP") is required to perform reliability studies with the expected generation pattern and the forecasted load. SPP criteria requires for one week notice for 230 kV line outages and before noon day ahead for 115 kV outages. These timing requirements are there so that the RC can study the bulk electric system and identify operational issues before approval is given for line outages. The SPP models all of the TOs' systems and is able to tell if an outage in another system is causing issues on the SPS transmission system and if an outage on SPS will cause issues on a neighboring system as well.

The ability to see all of the SPP footprint and more improves the reliability of the SPS system since outages on neighboring systems will impact flows on the SPS system and if unexpected, could cause overloads. SPP will also keep track of generation outages as well since generation patterns will also impact the flows on the system. If SPS experiences an unexpected transmission outage on the system, the SPS operator is required to enter the outage in the SPP outage system as soon as practical. All transmission outages are then forwarded by SPP to the NERC IDC system to identifying contributing schedules if TLR is required. If SPS is experiencing an issue on a transmission element that is not a monitored flowgate, SPP can (at SPS's request) establish a temporary flowgate so that the market will perform the constrained economic dispatch for the identified element. This provides a more economic and immediate process to relieve congestion.

B. Tariff Administration and Regional Scheduling

Q. Please discuss the SPP's Tariff Administration and Regional Scheduling functions.

A. The SPP Regional OATT[3] prescribes non-discriminatory rates, terms, and conditions for market participants within the SPP to transport power. The SPP administers that tariff by processing requests for transmission service and making

[3] http://www.spp.org/publications/SPP_Tariff.pdf

sure that the transmission paths are not overloaded. The SPP also acts as the settlement agent by collecting revenue from the entities who request transmission service and forwarding the appropriate amount of that revenue to the owners of the transmission facilities. In its role as tariff administrator, the SPP also follows other stakeholder-approved documents such as the SPP Market Protocols and the SPP Business Practices.

The SPP requires that load-serving entities provide plans showing how much energy they expect to withdraw from the grid in a given hour. The SPP also requires generation resources to submit plans showing how much energy they anticipate injecting onto the grid in a particular hour. The SPP is responsible for ensuring that the amount of energy that is delivered to the grid is matched with the amount that is needed to serve load. SPP's regional scheduling service reduces the number of entities with which SPP members and customers have to coordinate.

Q. Please further describe the steps SPP undertakes to fulfill its Regional Scheduling function.

A. The SPP ensures that the amount of power sent is coordinated and matched with power received. SPP's regional scheduling service reduces the number of entities with which SPP members and customers have to coordinate. SPP will monitor flowgate loading and scheduling to prevent over scheduling transmission facilities. SPP sends the schedules to all of the SPP BAs through the SPP RTO scheduling system (“RTOSS”) and each BA will utilize the schedule in its Automatic Generation Control (“AGC”) system to balance the balancing area.

C. Transmission Expansion Planning

(1) Transmission Planning Process

Q. Please discuss the SPP’s Transmission Planning function.

A. As a FERC-designated RTO, one of the SPP's responsibilities is to create regional transmission expansion plans. With its members, regulators, and stakeholders, the SPP creates planning models and studies that determine what and when new transmission is needed to meet the region's long- and near-term needs. This planning activity creates a cost-effective, flexible, and robust transmission network.

Q. Please provide a brief history of the SPP regional transmission planning process.

A. Before 2005, the transmission owning companies in the SPP footprint coordinated with SPP on projects that were needed for the reliability of the local areas being served.

Q. What changed in 2005?

A. The SPP, with RSC participation, approved the SPP Transmission Expansion Plan ("STEP"), which encouraged transmission expansion for reliability purposes utilizing region wide cost sharing.

Q. Why did SPP members, with RSC participation, decide to change to this region wide cost sharing methodology?

A. The SPP members as well as the RSC committee recognized that this process alone would not encourage the build out of transmission that was needed to recognize economic benefits. The stakeholders recognized that there were several projects that would have large economic benefits that fell just short of being justified solely on the reliability criteria. That is not to say that these projects would not add reliability benefits, but that they were not justified on the criteria at that time.

Q. What was the next step in the progression of regional transmission planning?

A. While the stakeholders were working on a regional planning process that would include cost allocation on a regional basis, the stakeholders also recognized that there were several projects that would add immediate benefits to the region. The stakeholders identified several projects and developed what was called the Balanced Portfolio.

Q. What is the Balanced Portfolio?

A. The Balanced Portfolio is a cohesive grouping of economic transmission upgrades that benefit the SPP region, the costs of which are allocated regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV transmission facilities that are intended to reduce congestion on the SPP transmission system, thus resulting in savings in generation production costs. These economic upgrades may provide other benefits to the power grid such as increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

Q. What was the next step in the evolution of the SPP transmission planning process?

A. Through the regional planning process and Balanced Portfolio, the SPP stakeholders transitioned to a process that took into account both reliability and economic benefits using an expanded cost allocation methodology to ensure those who benefit would also pay a reasonable portion of the costs. While this new allocation methodology was being approved, another set of projects were identified that would provide immediate benefits to the region. These were projects that were showing up on many future planning scenarios that also added immediate economic benefits. This set of projects was called the priority projects.

These were the first set of transmission projects whose costs were allocated based on the Highway/Byway methodology approved by SPP and FERC in 2010, which I discuss in further detail below. SPP then transitioned into the current process that is utilized today.

Q. Please summarize the current process the SPP uses for Transmission Planning.

A. As outlined in Attachment O of the SPP Regional OATT, SPP uses an integrated transmission planning process ("ITP"), which is an iterative three-year process.

A major objective of the ITP is the design and construction of a transmission backbone to connect load centers to known or expected large generation resources. The process seeks to target a reasonable balance between long-term transmission investment and congestion costs to customers. The ITP also integrates several existing SPP transmission planning processes into one coordinated assessment consisting of: (1) transmission service requests; (2) generation requests; (3) the Balanced Portfolio; (4) the high priority upgrades; (5) the 20 – Year assessment; (6) the 10 – Year assessment; and (7) the Near Term assessment.

Q. Briefly explain the components of the ITP planning process.

A. SPP is required by its tariff to incorporate new transmission service requests and generation interconnection requests into its transmission planning process to accommodate new service, load growth, and new generation additions to the system. In addition to those requirements, SPP performs the 20 – Year assessment, the 10 – Year assessment, and the Near Term assessment to identify the projects that are needed for a reliable and robust transmission system. The Balanced Portfolio and the Priority projects are included in the models since they have been approved and are in the planning and construction stage.

Q. Please describe the 20 - Year assessment.

A. The 20 - Year assessment is utilized for the purpose of planning the most beneficial and robust high voltage backbone in the future studying different scenarios since the future needs are uncertain. Several different scenarios will be studied and plans developed for each scenario. These plans will then be evaluated and one set of plans will be presented in the ITP 20 report. This process is repeated every three years. Assumptions used for the ITP 20 year report will be reevaluated during the first and second year of the three year cycle.

Q. Please describe the 10 - Year assessment.

A. The 10 - Year assessment is the second phase of the ITP process. Utilizing the results of the 20 - Year assessment, a set of plans studying several different scenarios are utilized to evaluate the need for ten years out down to the 100 kV voltage level. This assessment will be utilized to resolve potential violations of criteria, improve known and forecasted congestion, improve access to markets, staging transmission expansion, and improving interconnections. The results will be compiled into a 10 - Year assessment report and incorporated in the SPP transmission expansion plan on an annual basis.

Q. Please explain the Near Term Assessment.

A. The purpose of the ITP Near Term ("ITPNT") assessment is to determine the projects needed to meet reliability requirements. The ITPNT is performed on an annual basis. The results of the study will develop a set of projects 69 kV and above that will meet criteria while still incorporating the principals of the ITP process.

(2) SPP Cost Allocation for Transmission Infrastructure

Q. Is SPS affected by the SPP's method for allocating costs for new transmission infrastructure?

A. Yes. For example, in the SPS electric rate case currently pending before the Commission, Case No. 12-00350-UT, SPS's revenue requirement includes SPP costs that have been allocated to SPS under four different allocation methods: (1) Pre-2005; (2) Original Base Plan Funding; (3) the Balanced Portfolio; and (4) the

Highway/Byway. A matrix showing the effects of these methods during calendar year 2014, which is the test year in SPS's rate case, is shown in Attachment WAG-04.

Q. How were costs allocated under the Pre-2005 method?

A. Under this method, transmission owners were allocated all the costs for transmission projects located within their respective service territories. Thus, projects identified prior to 2005 had costs allocated in this fashion. It was not until the Original Base Plan Funding method that inter-zonal allocation of costs began.

Q. Please explain the Original Base Plan Funding for Transmission Upgrades.

A. Inter-zonal allocation of costs is the method of cost allocation for original base plan transmission upgrades. When Network or Reliability Transmission Upgrades are implemented, those SPP transmission customers benefitting most directly from the upgrade pay 2/3 of the costs with the remaining SPP transmission customers paying the remaining 1/3 of the costs. These upgrades were required to maintain reliability of the electric transmission grid. This methodology was utilized for projects identified from 2005 until June of 2010.

Q. How do SPP members pay for the Balanced Portfolio projects?

A. The allocation of costs associated with the Balanced Portfolio projects is intended to balance the benefits over the region. The SPP has begun to allocate those costs. A cost to benefit analyses is performed to ensure that the benefits are greater than the cost of the projects. In the analysis, the benefits were also studied on a zone by zone basis to ensure that every zone showed benefits greater than the allocated cost on a load ratio share or that zone would receive transfer payments to bring the deficient zone back to a 1 to 1 cost to benefit ratio.

Q. Have these transfer payments started?

A. Yes. In August of 2012, SPP filed the revisions to its OATT to implement the initial reallocation of revenue requirements pursuant to Attachment J of its tariff (provided as Attachment WAG-5)(FERC Docket No. ER12-2387).[4] The initial reallocation was authorized under the Balanced Portfolio because at least 10% of the levelized annual transmission revenue requirements for the approved Balanced Portfolio had been included in rates (*i.e.*, the "Trigger Date"). On each anniversary of the Trigger Date in the subsequent four years, an additional 20% of the Reallocated Revenue Requirement will be transferred to the Total Balanced Portfolio Region-wide Annual Transmission Revenue Requirement. The SPP

[4] *See* Attachment J of the SPP OATT at http://www.spp.org/publications/SPP_Tariff.pdf

filing requested to initiate these initial transfer payments on October 1, 2012. The FERC approved SPP's filing on November 20, 2012.

Q. What is the Highway/Byway cost allocation?

A. Highway/Byway funding was approved in 2010. This process splits the funding into three different categories: projects less than 100 kV; projects at or above 100 kV but below 300 kV; and projects over 300 kV. This methodology replaced the prior methods of cost allocation. Under Highway/Byway, projects below 100 kV are 100 % funded by the zone in which they are built, projects between 100 kV and 300 kV are funded 1/3 regionally and 2/3 by the zone in which they are built, and projects over 300 kV are 100% regionally funded on a load ratio share basis.

Q. How does SPP administer these cost allocations and collect the revenue for the regional transmission funding?

A. SPP administers the process through the methodologies contained in Attachment J of the SPP OATT and recovers the revenue through the resulting Schedule 11 charges under the SPP OATT. SPP collects both the zonal and any regionally allocated costs under Schedule 11. SPP then distributes this revenue to the Transmission Owners in accordance with their respective Attachment J.

(3) SPP Directives to Construct Facilities

Q. When Transmission Projects have been identified through the SPP transmission planning process and approved by the SPP Board of Directors, how are Transmission Owners notified to construct the projects?

A. Currently, when a project is approved, the SPP sends notice to the TO(s) in whose service territory the project is to be located. This TO is referred to as the "Designated Transmission Owner or "DTO." Written notification is provided to the DTO through a letter that includes the specifications of the project required by the SPP and a reasonable project schedule, including a project completion date. This letter is referred to as the Notification to Construct ("NTC").

Q. When are NTCs Issued?

A. After projects have been identified and approved, the SPP will issue a NTC within 15 business days for each Network upgrade for which a financial commitment is needed within the next four years. This is specified under section 7060 of the SPP OATT Business Practices.[5]

Q. What are the responsibilities of the DTO when a NTC is received?

A. To maintain its right to construct, the DTO is required to respond within ninety days after the receipt of the NTC. The DTO can respond with a commitment to

[5] http://www.spp.org/publications/SPP%20Business%20Practices%204_17_2012.pdf

construct as specified or submit a response with a different project schedule or alternative specifications.

If an amended proposal is provided by the DTO, SPP must respond within ten days of the receipt of the amended proposal. If the amended changes are rejected by SPP, the Transmission Owner can still accept the proposal if it is in the ninety day window.

Q. What happens if the DTO does not accept the NTC within ninety days?

A. In that event, SPP will solicit bids and evaluate proposals from other entities to construct the project. SPP will select a qualified entity based on, among other things, certain specific legal, regulatory, technical, and financial, and managerial qualifications. Upon selection, the replacement designated provider becomes the DTO.

Q. What happens if SPP is unable to find another qualified entity to construct a project?

A. The originally identified DTO will continue to have the obligation to construct the project under Section VI.2 of Attachment O and Section 3.3(a) of the SPP membership agreement.

Q. Can a DTO transfer its legal right to build?

A. Yes. Under Section 7070 of the SPS Business Practices, a DTO can assign or transfer its legal right to build. This assignment does not relieve the original DTO of the legal obligation to ensure that the project is built.

Q. Can the original DTO ever be released from the obligation to ensure that a project is built?

A. Yes. After the original DTO's assignment of the right to build to a new TO, a novation can be executed, which along with SPP Board approval, will transfer the obligation to construct to the new TO.

Q. How does the SPP's transmission planning function affect SPS?

A. As discussed previously, the Schedule 11 charges are assessed according to the SPP OATT and are based on a number of factors. SPS is a Balancing Authority known as Zone 11. As such, the retail customers of SPS are assessed Schedule 11 charges for their share of the regional and zonal transmission system projects. SPS witness Ruth M. Sakya discusses the specific Schedule 11 charges to be assessed to SPS.

Q. Please provide an example of how the allocation of these costs from SPP affect SPS's New Mexico retail customers.

A. SPS is required to obtain a certificate of public convenience and necessity ("CCN") from the Commission to construct and operate transmission lines that are located in New Mexico. When SPS submits CCN applications, it provides an estimate of what it will cost to construct the transmission facility. For example, in Case No. 12-00027-UT, SPS requested a CCN for the Pleasant Hill transmission facilities, which are two 230 kV transmission lines and associated substation facilities in Curry and Roosevelt Counties, New Mexico. In that application, SPS provided a cost estimate of $60,000,000 to construct the facilities. This translates into an approximate annual revenue requirement of $9.1 million.

However, the full $9.1 million annual revenue requirement related to the Pleasant Hill transmission facilities will not be allocated to SPS. Because the facilities are less than 300 kV, under the Highway/Byway cost allocation, the facilities are funded 1/3 regionally and 2/3 by the zone in which they are built. Thus, 2/3 of the $9.1 million annual revenue requirement (or approximately $6.1 million) will be allocated to the SPS zone. In addition, 1/3 or approximately $3 million would be assigned to the SPP region. Within the region, SPS's share is 12.9812%, which reflects SPS's load ratio share. Thus, of the $3 million annual revenue requirement assigned to the SPP region, SPS will be allocated approximately $391,000. In total, approximately $6.5 million of the total annual revenue requirement of approximately $9.1 million is allocated the SPS zone. Within the SPS zone, approximately 16.4868% is allocated to the New Mexico jurisdiction, which reflects New Mexico's 12-coincident peak transmission demand allocation. Therefore, of the $6.5 million annual revenue requirement allocated to SPS, approximately $1.1 million is the annual revenue requirement that will be allocated to the New Mexico jurisdiction. Thus, SPS's New Mexico retail jurisdiction would pay only approximately $1.1 million out of the approximately $9.1 million total revenue requirement, or approximately 11% of the total revenue requirement.

(4) Other Transmission Planning Activities

Q. Are there any other transmission expansion planning activities currently taking place at the SPP?

A. Yes. SPP and its members are working to comply with FERC Order No. 1000[6] and also are consolidating the Balancing Authorities within its footprint.

Q. What is the SPP required to do to comply with Order No. 1000?

A. Among other items, Order No. 1000 requires regional transmission planning with a regional cost allocation methodology for particular new transmission facilities that meet regional cost allocation principles. At its October 30, 2012 meeting, the SPP Board of Directors approved language for a filing at FERC to comply with

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

Order No. 1000. The language is a proposed tariff provision that specifies the process that will identify the DTO under these new guidelines.

D. ***Market Operations***

Q. Please discuss further the Market Operations function of the SPP.

A. In 2007, SPP implemented the EIS Market, which is a wholesale market that operates under a tariff approved by the FERC. Through the EIS Market, the SPP aims to reduce the overall production costs of serving load by optimizing the dispatch of generation across the SPP footprint and improve reliability through more precise control of power flows on the transmission system. SPP administers the EIS Market, oversees market activities, ensures reliability, forecasts supply requirements, and provides market monitoring oversight. In the EIS, a market participant settles with SPP for imbalance service when a difference occurs between a generator's scheduled output or a load's scheduled withdrawal and the actual metered generator output or load withdrawal volumes in an hour. The EIS utilizes Locational Imbalance Prices ("LIP"), which are calculated every five minutes but averaged over the hour to create hourly settlement prices. The LIP reflects the incremental cost of delivering energy to specific locations on the transmission grid. The EIS Market is an optimal dispatch solution for units that the market participants have committed to meet their load and reserve obligation. In the EIS Market, the SPP is not the responsible party for committing units.

(1) <u>The Integrated Marketplace</u>

Q. What future plans does the SPP have for market operations?

A. On February 29, 2012, SPP filed tariff revisions at FERC to implement the new Integrated Marketplace ("IM") for the region, moving SPP to a two-settlement, LMP energy market model, like the Midwest Independent System Operator ("MISO"), the PJM ISO, and other established RTO administered markets.

Q. When is the SPP Integrated Market expected to become operational?

A. The SPP expects the IM to go into effect on March 1, 2014. FERC conditionally approved the IM on October 18, 2012.[7]

Q. What is the primary difference between the EIS and IM?

A. The EIS Market is a constrained economic real time dispatch of the units that the BAs have committed to optimize the real time balancing of load and generation. The IM is a fully integrated market that not only still performs the constrained economic dispatch, but also optimizes the market by performing a day-ahead market with unit commit.

Q. Please describe further how the SPP Integrated Marketplace will operate.

[7] *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012).

A. The IM will include day-ahead ("DA") and real-time energy and operating reserve markets and transmission congestion rights markets. In addition, the existing 16 Balancing Authorities in the SPP market footprint will consolidate to form a single Balancing Authority. The IM will determine the most cost-effective generating units to commit and dispatch the following day, determine the required reserves, increase the balancing of regional supply and demand, and aid in the integration of renewable resources. SPP estimates the new marketplace will result in net benefits throughout the SPP region of $45 – $100 million per year.

This type of regional market uses a "two-settlement" system where participants make binding day-ahead financial commitments and then settle any deviations from their day-ahead commitments or load forecast in a real-time balancing market. As proposed, the implementation of the IM includes a centralized unit commitment system; further optimizing the use of generation resources within the SPP footprint to serve load more economically because the commitment is spread over a larger region.

When the IM takes effect, SPP will serve as the reliability coordinator, balancing authority, transmission service provider, planning coordinator, reserve sharing group administrator, interchange authority, and market operator.

Q. Please describe the day-ahead market component of the SPP Integrated Marketplace.

A. SPP's day-ahead market is designed to determine the least-cost solution to meet the market's energy needs and reserve requirements. To accomplish this objective, market participants are required to submit offers to sell services provided by generation including energy, reserves, and other ancillary services. Market participants serving load will also bid in all or a portion of their forecasted load to be cleared in the day-ahead market. SPP will then select the most cost-effective mix of resources to meet the load forecast for the operating day. SPP will also include a "must offer" requirement equal to the amount of forecasted load and reserve obligation, in the day-ahead settlement to ensure enough physical resource capacity to satisfy the need of the market. The "must offer" requirement is required of all generation for the reliability unit commitment ("RUC") performed in the real time market.

SPP will perform a several RUC runs. One will be the day before the day-ahead market clearing or two days before the active day. Then the day-ahead market will run and clear by 4:00 p.m. the day prior. When the day-ahead market has cleared, a day-ahead RUC will be performed once more and determine if the reliability needs are met. This study will be performed with the latest updated load forecast to ensure adequate resources are committed. Import and export schedules that are submitted will also be part of the evaluation. During the market day, RUC will be perform through out the day but at least every four hours to ensure reliability for changing system conditions.

Q. Please describe the operating reserve market component of the SPP Integrated Marketplace.

A. The operating reserve market design calls for market procurement and dispatch of Regulation Reserve, Spinning Reserve, and Supplemental Reserves. As with the energy market, the operating reserve market is also a multi-settlement market clearing in the day-ahead with deviations being settled in real-time. Offers submitted for any or all services are cleared in priority with a co-optimized algorithm to achieve the least cost overall solution for energy and reserve products.

Q. How will SPP perform the load balancing function?

A. SPP will be responsible under the NERC requirements as a BA to ensure balance of resource and procurement of ancillary services. As mentioned earlier, regulation, spinning, and supplemental reserves will be market bids that will enable SPP to clear the necessary resources.

Q. Will SPS still be responsible for the reliability of the SPS system?

A. As TOP, SPS will still be responsible for the reliability for the SPS transmission system. SPS will still be performing a forecast and transmission stability studies to see if the SPS system meets NERC criteria. If the SPS TOP sees an issue, they will work with SPP to address the problem. If time does not permit the coordination with SPP, the SPS TOP will still have the authority to address real time operating issues as needed including committing generation for reliability.

Q. If SPS is no longer in control of the generation dispatch for the SPS region, how is the SPS customer protected from prices caused by congestion?

A. The IM will have a Transmission Congestion Right ("TCR") Market. A TCR can be used as a hedge to reduce the risk of exposure to high market prices.

Q. Describe the TCR market in more detail.

A. The TCR market will have two products. One product is the Auction Revenue Rights ("ARRs") and the other is the TCRs. The ARRs are a Market Participant's ("MP") entitlement to a share of revenue generated in the TCR auctions. These rights are allocated annually to MPs based on firm transmission rights on the SPP transmission system and these are both firm point to point as well as network rights. The TCR is an entitlement to a share of revenue generated in the DA market. A TCR is used to mitigate congestion exposure in the DA market. MPs can obtain the TCRs through the annual or monthly auctions by either converting their ARR to a TCR or by bidding to purchase TCRs in the auctions.

Q. How is the revenue of the TCR calculated?

A. The holder of a TCR for a transmission path would be given revenue based on the day-ahead market solution when there is congestion on a path. For example if SPS holds a TCR for 100MW on a path from a generator to load and is scheduled to send 100MW down the path and congestion occurs, there will be a day-ahead price separation between the generator and the load. The difference of the price separation times the amount of the flow up to the amount of TCR held would determine the revenue SPS would receive for that TCR. If the price separation was $10 (generator cost of $20 and load node price of $30 for example), SPS would receive $1000 for the TCR. SPS would then use that $1000 to offset the actual congestion cost of $1000 for the transaction and would be fully hedged for that transaction.

Q. In your opinion, will the Integrated Marketplace provide benefits to SPS's New Mexico customers above the current EIS Market?

A. Yes. Although the EIS market has worked well and resulted in substantial cost saving benefits for SPS customers, there are still more savings in a fully integrated market that can be realized with the centralized unit dispatch proposed in the IM. A fully integrated market will also provide data that will identify the cost of transmission constraints that can be compared to the cost to upgrade the transmission system by putting a value on the congestion.

(2) <u>Consolidation of the balancing authorities to the SPP</u>.

Q. Why has the SPP concluded it must consolidate the 16 Balancing Authorities into one Balancing Authority?

A. As noted above, to recognize the benefits of the IM, SPS and the current Balancing Authorities will need to turn over the Balancing Authority responsibilities to SPP. This transfer will allow SPP to perform the function of reliably dispatching generation on a region wide basis instead of each of the existing 16 Balancing Authorities performing that service today. The transfer of this function to the SPP will allow SPS and its customers to recognize the benefits of a region wide unit commitment and dispatch.

Q. Is it in the interest of SPS customers for the SPP to operate as a consolidated Balancing Authority?

A. Yes. Based on my past experience, there are benefits to SPS customers for the SPP to operate as a consolidated Balancing Authority as a part of the transition to the IM. These benefits stem from the availability of a more diverse set of pooling resources to serve the needs of SPS's customers and potentially lower production costs.

E. ***<u>SPS's involvement in the SPP Policy Development and Transmission Planning.</u>***

Q. Earlier in your testimony you addressed the stakeholder influence in the SPP and SPS's involvement in committees. Can you provide additional examples of SPS's efforts to help influence SPP policy?

A. Yes. SPS has influenced the SPP's STEP. When SPP was developing the regional transmission expansion plan, there was a strong push to build 765 kV extra high voltage backbone to the future plans. Although SPS is not opposed to 765 kV transmission projects, SPS concluded that the initially proposed 765 kV projects could not be justified in a cost benefit study ("CBS") and, therefore, strongly opposed them through several stakeholder meetings and several votes of the membership. SPS worked very closely with commission participants on the RSC and CAWG during this debate. As a result these efforts, the SPP changed the projects to 345 kV lines, which are less expensive to construct, operate, and maintain.

Q. How active is SPS in working in the transmission planning process?

A. During the assessment period, SPS transmission is very active in assessing the projects and the alternatives, if any, to the proposed projects. SPS transmission group works with the SPP planning department in developing projects that meet the needs of the SPS area. When SPP finishes the near term assessment, NTCs will be issued to the DTO.

Q. Do you have examples of when SPS's identification of alternatives saved money for SPS's customer?

A. Yes. SPS has questioned, as a DTO, NTCs it received from the SPP. One example occurred in 2009 when, a result of the 2009 STEP, SPS received NTCs for approximately $450 million of new construction projects. The STEP included NTCs that required extensive reconductors or wreckout/rebuilds of urban SPS transmission lines in and around the City of Amarillo. One large project in that list of NTCs was the construction of the Potter Co (Amarillo) – Frio Draw (Clovis) 345 kV line. SPS requested revaluation of many of the projects in this set of NTCs. Specifically, SPS asked for a re-evaluation of the 345 kV Potter-Frio Draw line, the extensive transmission line reconductors within the City of Amarillo, the Hobbs-Seminole 230 kV project, and the Hitchland – Pringle 230 kV line project, among others. Among other items, SPS requested and worked with SPP and stakeholder to amend the criteria used in SPP reliability studies to allow committed projects, as well as new generation. Once the new criteria were used and the re-evaluation was complete: (1) the 345 kV line from Potter-Frio

Draw was no longer needed; (2) the reconductors of the urban transmission lines in Amarillo were unnecessary; (3) the Hobbs-Seminole 230 kV line showed it was not needed; and (4) Hitchland – Pringle 230 kV line was not needed.

Another example regarded the generation interconnection study for the Jones 4, Quay County, and Mustang 6 generators. The study that the SPP performed showed the need to build transmission to accommodate the addition of the generators. SPS asked the SPP to perform a limited operations interconnection study to determine if the upgrades could be deferred if SPS added some power system stabilizers to some of the generation in the area. The results of this study showed that the initially-proposed 345 kV project from Amarillo to Lubbock could be deferred with the addition of the power system stabilizers. This reduced the total cost of the required network upgrades from almost $150 million to approximately $11.4 million.

In addition to the above, SPS also reviews NTCs to determine if the costs of such facilities have been appropriately allocated. An example relates to an NTC that included the addition of a second transformer at the Hitchland substation. SPS believed the second transformer was not needed to support the reliability or growth of SPS's customers located in the area, but was identified for projected wind resources to be interconnected. Thus, SPS asserted that the cost of this transformer should not be borne by its customers but should be uplifted to the region. This issue was raised to the SPP Board of Directors in October 2011. The SPP Board of Directors agreed with SPS's position and granted a waiver for the cost of the transformer to be borne by the region instead of direct assigned to the SPS Zone.

VII. BENEFITS OF SPS'S CONTINUED MEMBERSHIP IN THE SPP

A. Production cost saving analyses required by the Stipulation.

Q. Earlier in your testimony, you said SPS determined its customers have saved approximately $19.28 million through SPS's membership in the SPP. How and where are customers realizing these savings?

A. Through SPS's participation in the EIS Market, SPS customers benefit because SPS has the option to reduce the operation of its generation and purchase lower cost energy from the EIS Market to serve energy imbalances associated with its load. SPS can further offer its generation into the marketplace for use on an incremental basis and collect incremental revenue from off-system sales into the market.

By replacing the generation of its own units with lower cost purchased power through the EIS Market, the costs recovered through the Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") are reduced significantly. Any revenues created by any economy sales that SPS is able to make through the EIS Market are also flowed through the FPPCAC for SPS customer benefits.

Q. Please describe the analysis SPS undertook to arrive at the $19.28 million production cost savings and revenues as a result of SPS's membership in the EIS Market.

A. To determine the production cost savings resulting from SPS's activity in the EIS Market from February 2010 to November 2012, SPS needed to determine what the costs would have been for purchases and sales during the time frame absent the EIS Market. The difference between the two scenarios represents the savings achieved. To determine the "costs" for the purchases, SPS stacked the purchases on a priority basis since EIS Market purchases come last, i.e., after bi-lateral purchases. In particular, SPS stacked all the day-ahead purchases, and then the real time purchases sales, including those from the EIS Market. After the order was determined, SPS used GenTrader® to calculate the avoided costs of those purchases. GenTrader showed additional production costs (and thus savings) through purchases during this period of $31.4 million dollars, which includes $15.3 million through the EIS Market.

For sales, the "costs" associated with not making them was the lost margin from these sales during the time frame. Thus, SPS went back and removed the margins gained from the sales to arrive at a total cost of sales during this time frame absent the EIS Market. SPS sales during this period were $25.7 million, which includes $3.96 million of margins gained through the EIS Market.

SPS then added together the costs of the purchases and sales absent SPS's EIS Market participation and compared that to the actual costs for both through the EIS Market. The difference between the two scenarios of costs was $19.28 million. Thus, a total economic benefit of $19.28 million during this time period resulted from the EIS Market.

Q. Please describe the analysis SPS undertook to arrive at the $43.7 million production cost savings and revenue estimate that will result on a going forward basis as a result of SPS's membership in the EIS Market.

A. Utilizing a ProSym model with the forward gas prices and the forward SPP prices[8], SPS performed an estimated production cost savings from purchases and sales in the market for the remainder of the Interim Period. The results cover a period from December of 2012 to February of 2015 and show an estimated production benefit of $43.7 million for activity during this period. Recall that the Integrated Marketplace is scheduled to become effective in March of 2014. Thus, the forward-looking estimate is higher than what has been achieved under the EIS Market alone, since under the IM the DA market and the centralized generation

[8] SPP forward market power prices are developed using fundamentally-based forecasts from Wood Mackenzie and IHS CERA. The forward price forecast for SPP is based on the average of the implied heat rates from the Wood Mackenzie and CERA forecasts multiplied by the NYMEX natural gas futures price. Information about IHS CERA and Wood Mackenzie can be found on their respective websites:

IHS CERA: www.ihscera.com
Wood Mackenzie: www.woodmacresearch.com

unit commitment will further optimize the use of generation resources within the SPP footprint.

Q. Explain further the incremental benefit to the SPS customers from the DA market.

A. The DA market will not only provide opportunity to facilitate the purchasing and selling in the market to supplement the bi-lateral activity, it also serves to firm up transactions which will benefit on the unit commitment. Many of the purchases mentioned in the backward-looking production cost savings analysis were non-firm transactions, which would be backed up by reserves pursuant to SPP criteria. In the DA market, transactions will be considered firm and financially binding.

B. Other cost-saving benefits continue as a result of SPS's participation in the SPP.

Q. In addition to the production cost savings achieved since the February 2nd Order and the estimate on a prospective basis, what other cost-saving benefits do you envision resulting from SPS's continued participation in the SPP?

A. The Certification identified other cost-saving benefits resulting from the SPS membership in the SPP. Those benefits were:

- Cost savings resulting from the contingency reserve sharing agreement with SPP members.

- Cost savings resulting from reduced capacity from SPS's participation in the SPP reserve-sharing group.
- Labor cost savings resulting from the SPP acting as the regional transmission planning coordinator, processing wholesale generation interconnection requests, and processing firm transmission service requests.

Each of these will continue on a prospective basis, as discussed further below.

(1) Savings from the SPP contingency reserve sharing agreement

Q. Why will SPS's customers continue to experience cost savings as a result of the SPP contingency reserve sharing agreement?

A. As part of providing reliable electric service, SPS and other utility BAs maintain contingency reserves to restore system balance between generation and load in the event of a sudden resource outage. It would be quite expensive for each BA to provide full backup for the generating resources within its boundaries. The BA is able to decrease the amount of contingency reserve required by pooling reserves under a reserve sharing arrangement.

Absent the reserve sharing agreement, SPS would need to provide contingency reserves to account for an unplanned outage of its Tolk generation facility, which is 540 MW, half of which needs to be spinning reserves. This means that 540 MW would need to be in place, and 270 would need to be spinning (*i.e.*, using fuel), but not generating electricity or being dispatched to respond to an outage at Tolk or another larger unit on the SPS system.

With the SPP reserve sharing agreement, the reserve sharing group members collectively respond to an unplanned outage of generators on SPS's or any transmission providers' system within the SPP region. As a result, SPS is responsible for only a portion of the contingency reserve it would otherwise be required to meet NERC reliability criteria. The Certification noted that the reserve sharing agreement resulted in SPS needing to obtain 140 – 180 MW of contingency reserve.

Q. What types of cost savings will SPS's customers experience as a result of the SPP reserve sharing group agreement?

A. There are two types of cost savings SPS and its customers experience. The first is a reduction in fuel and start up costs associated with maintaining sufficient contingency reserves. The second is the reduction in procuring a lower amount of capacity margin.

Q. With regard to the first type of cost savings, what amount do you estimate SPS's customers will save through lower fuel and start up costs associated with maintaining sufficient contingency reserves?

A. As noted earlier, absent the reserve sharing agreement, SPS would be required to procure 540 MW in contingency reserves. With the reserve sharing agreement, that amount is roughly 180 MW. The reduction of 360 MW is the amount saved, which directly translates into avoided start up and fuel cost savings.

To provide an estimate the savings resulting from avoided start up and fuel costs, SPS performed a production cost study with two different reserve requirements for 2014, One reserve requirement was for 540 MW, which would be required for SPS as a stand alone BA to cover the loss of the largest unit (either of the Tolk units) and the other requirement was for 178 MW, which represented the amount of reserves SPS anticipates carrying in 2014 under the reserve sharing agreement. The results showed annual savings of $80.9 million dollars. The major change in the $135 million in savings estimated for 2009 in the Certification is the drop in projected natural gas prices at a range of $3.19/MMBTU to $3.82/MMBTu for 2014 as compared to an average of $9.16 MMBTU used in the 2008 study.

Q. What amount do you estimate SPS's customers will save through the need to procure a reduced amount of contingency reserves?

A. In addition to the reduction in costs for avoiding spinning reserve capacity on the SPS system and reduced start-up costs for supplemental reserve capacity, membership in the contingency reserve sharing agreement also reduces the capacity margin SPS is required to provide to meet NERC standards. Under NERC reliability standards, a BA would have to replace the contingency reserves within 90 minutes after the end of a disturbance period following the trip of generation unit. For SPS to have enough resources to restore the contingency reserves of 540 MW instead of the 180 MW after the trip, it would have to carry approximately 360 MW more of planning reserves.

To determine the savings attributable to the reduced capacity margin, it is necessary to determine how much the incremental 360 MW of planning reserves would cost to procure. Based on current levelized capacity market prices of $7.63/kw month, the savings achieved by avoiding procuring 360 MW is approximately $2.747 million a month or $32.96 million on an annual basis.

(2) SPS's labor cost savings due to SPP services

Q. Earlier, you listed cost savings from the SPP acting as the regional transmission planning coordinator, processing wholesale generation interconnection requests, and processing firm transmission service requests. In your opinion, will SPS's customers continue to experience those cost savings?

A. Yes.

Q. What are the estimated labor cost savings SPS's customers will experience as a result of the SPP performing transmission planning for its members such as SPS?

A. The Certification cited SPS's testimony that in order for SPS to replicate the transmission planning performed by the SPP, SPS would need to incur $333,000 per year to perform transmission planning for the SPS system. In addition, the Stipulation noted the SPP develops regional transmission engineering models that SPS uses in powerflow studies and dynamic stability studies. If SPS were required to complete those studies on its own, the cost of these studies would be in excess of $100,000 a year. These assumptions remain true today.

Q. What are the estimated labor cost savings SPS's customers will experience as a result of the SPP processing wholesale generation interconnection requests?

A. When wholesale generation interconnection requests are processed, three sequential studies are performed. SPP performs the first two studies, *i.e.*, the Feasibility and System Impact Study. SPS performs the last study, which is the Facilities Study. At the time, SPS noted if the SPP were not involved in the generator interconnection process, SPS would need a minimum of three additional planning engineers to perform the Feasibility and System Impact Studies, at a cost of approximately $250,000 per year, as well as increased contract management, regulatory, and legal support to facilitate the execution of interconnection agreements with generation developers. SPS still estimates it would need a minimum of three additional planning engineers to fulfill SPP's role in processing these requests.

Q. Why will the labor cost savings continue for SPS's customers as a result of the SPP processing all long-term firm transmission service requests?

A. The SPP RTO studies all long-term firm transmission service requests in a given time period in an SPP Aggregate Transmission Service Study. The SPP RTO targets three studies for transmission service per year. The studies identify network transmission upgrades required to support the requested service, and the required in-service dates for the projects. By SPP performing these functions, SPS New Mexico retail customers benefit by reduced internal labor costs and outside consulting costs that would otherwise be required. These benefits were similarly recognized in the Certification.

Q. If SPS was fully administering the Xcel OATT instead of SPP providing tariff and scheduling services, would SPS incur additional labor coat?

A. Yes, SPS would have to hire additional accounting and tariff administration personnel to administer and account for the tariff charges. SPS estimates that an additional $295,000 per year to perform these task.

Q. In addition to the cost-saving benefits resulting from the SPS's continued participation in the SPP, will SPS experience qualitative benefits?

A. Yes. There are several qualitative benefits derived from SPS's continued membership in the SPP. These benefits include increased reliability, more efficient use of existing transmission and generation assets, increased access to external generation and load, and increased regional transmission planning and expansion coordination. These benefits were also recognized in the Certification.

Q. Can you provide an example to further illustrate the increased reliability and more efficient use of generation assets through membership in the SPP?

A. Yes. SPS is scheduled to have two 345kV tie lines in service by summer of 2014. The two new lines are part of the Balanced Portfolio and the Priority Projects. These lines will strengthen the connection of SPS to the Eastern Interconnection. SPP has performed a stability analyses for the SPS system with and without these two lines. The results of this study show that beginning in 2018 the two lines would help support the forecasted 550 MW load increase on the SPS transmission system while also providing for an additional import capability of 550 MW. The increase in the import/export capability will provide greater access to the rest of the interconnection, which will increase market access and provide increased reliability to the region.

VIII. ADDITIONAL COSTS OR OTHER BURDENS RELATED TO SPS'S CONTINUED PARTICIPATION IN THE SPP RTO

Q. The Stipulation required SPS to document any additional costs or other burdens related to SPS's continued participation in the SPP. What costs does SPS incur as a result of its membership in the SPP?

A. SPP assesses transmission owners a Schedule 1 Administrative Rate, which is designed to recover the SPP's operating and debt service costs, with adjustments for any over-collections or under-collections. The administrative fee relates to several services provided by SPP, including reliability coordination, tariff administration, and seams agreements. The fee is annually set by the SPP Board of Directors based on the preceding year's anticipated budget, including reconciliation from the previous year's over-or-under-collection. The fee is assessed based upon transmission services purchased or provided pursuant to the SPP Tariff.

Q. What was the SPP administrative fee for 2011 and 2012?

A. The fees were:

Year	Fee
2011	$0.21/MWH
2012	$0.255/MWH

Q. How does SPP collect these administrative fees?

A. SPP collects these fees through Schedule 1-A of its OATT.

Q. What is the SPP administrative fee for 2013?

A. The SPP Board of Directors approved a fee of $0.315 per MWH for 2013. This increased amount reflects the Entergy Operating Companies decision to transfer the Independent Coordinator of Transmission ("ICT") function from the SPP to MISO.

Q. What is the estimated administrative fee for 2014?

A. The estimated cost for 2014 is $0.37 per MW per hour. As reported in the SPP Finance Committee report, the fees were based on the projected costs based on the estimated numbers of employees and the cost of providing services. The SPP Finance Committee report indicated a leveling of fees around the $0.37 since the increase has been based on increases due to the market start and increased planning activities.

Q. In addition to the administrative fee, what other costs does SPS incur as a member of the SPP?

A. As noted above, SPP collects and allocates revenue for transmission funding. SPP administers the process through the methodologies contained in Attachment J of the SPP OATT and recovers the revenue through the resulting Schedule 11 charges under the SPP OATT. SPP collects both the zonal and any regionally allocated costs under Schedule 11. SPP then distributes this revenue to the Transmission Owners in accordance with their respective Attachment J.

In addition, SPS can be assessed charges and earn revenues through its participation in the EIS Market. SPS Witness Ruth M. Sakya addresses costs related to the SPP membership further in her testimony.

IX. SPS's REQUESTS OF THE COMMISSION

Q. What relief is SPS requesting from the Commission in this case?

A. SPS asks the Commission to grant the following relief:

(1) find that SPS's Interim Report satisfies SPS's reporting obligation under Section 4 of the Stipulation;

(b) find that the benefits resulting from SPS's participation in the SPP membership outweigh the costs of such participation and support SPS's participation in the SPP on a permanent basis; and

(c) grant SPS permanent approval to participate in the SPP, including the transfer of SPS's retail load to the SPP OATT.

X. CONCLUSION

Q. Are Attachments WAG-1 through WAG-5 true copies of the documents you have represented them to be?

A. Yes.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF AN INVESTIGATION INTO THE PRUDENCE OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S PARTICIPATION IN THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION,	)	Case No. 07-00390-UT
SOUTHWESTERN PUBLIC SERVICE COMPANY	)	
Respondent.	)	

UNCONTESTED STIPULATION

The parties to this Uncontested Stipulation (Stipulation), which is dated as of September 17, 2009, are Southwestern Public Service Company (SPS); the Utility Division Staff (Staff) of the New Mexico Public Regulation Commission (NMPRC or Commission); the Attorney General of the State of New Mexico (AG); Central Valley Electric Cooperative, Inc. (Central Valley); Farmers Electric Cooperative, Inc. (Farmers); Lea County Electric Cooperative, Inc. (Lea County); Roosevelt County Electric Cooperative, Inc. (Roosevelt); and the Southwest Power Pool, Inc. (SPP). The foregoing shall be referred to individually either as a Signatory or by the acronym assigned above, and collectively as the Signatories. Occidental Permian Ltd. does not oppose the Stipulation.

On October 16, 2007, in Case No. 07-00390-UT, the Commission issued its Order requiring SPS to file direct testimony addressing, "from the New Mexico retail customers' perspective, a cost/benefit analysis of SPS's participation in the SPP that demonstrates, among other matters, a quantification of any reduction or increase in SPS's administrative and general and other costs as the result of its participation in the SPP, the impact, if any, on SPS's purchased power and fuel costs and reliability of service, and the impact of that participation on the Commission's ability to protect the interests of New Mexico consumers under the Public Utility Act." On July 31, 2008, SPS filed the direct testimony of four witnesses in response to the Commission's Order in Case No. 07-00390-UT. On May 1, 2009, the SPS filed an Unopposed Motion to Expand the Scope of this case to include review and approval of SPS's transfer of its New Mexico retail load to the SPP Regional Open Access Transmission Tariff (SPP Regional

OATT), and on June 9, 2009 the Commission granted the Motion. On June 29, 2009, SPS filed supplemental testimony addressing matters in the expanded scope ordered by the Commission. For convenience, SPS's July 31, 2008, and June 29, 2009, filings shall be referred to collectively as the "SPS Filing."

The Signatories submit this Stipulation to the Commission as representing a just and reasonable disposition of the issues related to this case consistent with the public interest; the Signatories request that the Commission enter its final order approving this Stipulation.

By this agreement, the Signatories resolve all issues between them related to the Commission's investigation, and the expanded scope of the case, and stipulate and agree as follows:

Section 1. Support for Approval of SPS's Participation in the SPP Regional Transmission Organization (RTO)

a. Subject to the agreements in this Stipulation and solely on a New Mexico retail jurisdictional basis, the Signatories agree that it is appropriate for SPS to participate in the SPP, including but not limited to: the reliability aspects of the SPP RTO (reserve sharing group and Regional Reliability Coordinator); and the regional wholesale transmission service and energy markets administered by the SPP RTO, including regional transmission service, generation interconnection administration, and Energy Imbalance Service (EIS) market administration. The Signatories acknowledge that – as a member of SPP – SPS is required by SPP to transfer its New Mexico retail load to Network Integration Transmission Service (NITS) under the SPP Regional OATT no later than February 1, 2010, pursuant to Sections 1.44a and 38.2 of the SPP Regional OATT. While the Signatories do not oppose this SPP requirement, nothing in this Stipulation shall be construed as implying that the Commission is bound to automatically pass through the resulting wholesale transmission costs into the transmission component of the bundled rates paid by New Mexico retail customers.

Accordingly, the Signatories support the entry of an order by the Commission determining, on a New Mexico retail jurisdictional basis, that SPS's participation in the SPP on the terms outlined in this Stipulation is prudent, reasonable and in the public interest and that the approvals granted in this proceeding are the only approvals required from the Commission.

b. The Signatories also acknowledge that SPS is under the ongoing jurisdiction of the North American Electric Reliability Corporation (NERC) as the designated Electric Reliability Organization pursuant to the Energy Policy Act of 2005 and FERC Order No. 693, the separate SPP Regional Entity (RE) function by delegation agreement with NERC, and the Federal Energy Regulatory Commission (FERC) with regard to compliance with mandatory electric reliability standards adopted pursuant to Section 215 of the Federal Power Act (2005) and FERC Order No. 693 *et seq.* Nothing in this Stipulation is intended to affect the jurisdictional relationship between the SPP RE function (or any successor thereto) and SPS.

c. Commission approval of this Stipulation does not establish a rebuttable presumption, nor justify for the recovery in retail rates, any of SPS's costs, fees or charges paid or to be paid to SPP. The reasonableness of all costs resulting from SPS's participation in the SPP RTO and claimed for retail rate recovery in Commission proceedings, will be determined by the Commission.

Section 2. Interim Nature of Approval Relating to SPS's Participation in the SPP RTO

The Signatories support the entry of an order by the Commission determining that SPS's participation in the SPP RTO is prudent, reasonable and in the public interest on an interim and conditional basis during a term of five years from the date permission is granted by final Commission order (Interim Period). If the Commission rescinds its approval pursuant to the terms of this Stipulation, the Commission has the jurisdiction to require SPS to timely initiate any notices, filings, and actions necessary to seek withdrawal of SPS's New Mexico retail load from the SPP Regional OATT and SPS acknowledges that there is a possibility that the Commission could issue such an order. If the Commission does not issue an order to terminate or extend its interim approval prior to the end of the Interim Period, the approval of SPS's participation in the SPP and the transfer of SPS's retail load to the SPP Regional OATT shall no longer be deemed to be interim.

Section 3. Changes to the SPP Administrative Fee During Interim Period

If the SPP's administrative charge in Schedule 1-A of the SPP Regional OATT, effective as of October 16, 2007, excluding the portion of the charge related to the provision of additional market related services, increases by more than 25 percent above $0.19 per MWh, SPS shall file with the Commission a pleading within 60 days of the latter of (a) the date that the SPP's Board of Directors approved such a charge, or (b) the date FERC accepts a change in the Schedule 1-A rate proposed by SPP, if applicable. The pleading will be served on the parties to this proceeding and will address the reasons for the increase in the Schedule 1-A charge and the merits of SPS's continued participation in the SPP.

Section 4. Required Filing Two Years Before End of Interim Period

Two years before the conclusion of the Interim Period, SPS will file with the Commission and serve on the parties to this proceeding a report (Interim Report) regarding SPS's continued participation in the SPP RTO. That filing shall contain a comparison of actual production costs from participation in the SPP EIS market to an estimate of SPS energy costs absent SPS's participation in the EIS market during the period between the Commission final order approving the Stipulation and date of the Interim Report. The Interim report shall also contain a comparison of estimated production costs for participation in the SPP EIS market to an estimate of SPS energy costs absent SPS's participation in the EIS market during the period between the date of the Interim Report and the end of the Interim Period. The SPS filing may also document other benefits, and shall document any additional costs or other burdens, of SPS's continued participation in the SPP RTO.

Section 5. Change in Membership or Load Functions of SPP RTO

If at any time during the Interim Period: (a) the combined impact of additions to and departures from the membership in the SPP RTO results in a 25 percent decrease in the total load of the participants that were anticipated in the SPP Regional State Committee's Cost-Benefit Analysis to participate in the SPP EIS market (geographic scope provision) (dated July 27, 2005), or (b) there is a final FERC order during the Interim Period approving a change in the list of functions performed by the SPP RTO from those set out in FERC orders issued February 10, 2004, and October 1, 2004, granting SPP RTO status[1] (RTO function provision), then, within 60 days of such event, SPS will provide written notification to the Commission and the parties to this proceeding of the change in the SPP RTO scope or the change in the SPP RTO function.

[1] Southwest Power Pool, Inc., 106 FERC ¶ 61,110 (2004); *order on reh'g* 109 FERC ¶ 61,010 (2004).

Section 6. Network Integration Transmission Service

As a participant in the SPP as contemplated in this Stipulation, and as required by Sections 1.44a and 38.2 of the SPP Regional OATT, SPS will contract to use NITS pursuant to the SPP Regional OATT to serve its New Mexico retail load effective January 1, 2010. In this regard, SPS will be subject to all rates, terms, and conditions of the SPP Regional OATT other than those set out for exclusion in the Network Integration Transmission Service Agreement (NITSA) discussed in Section 7, below. In addition, SPS and SPP will enter into a Network Operating Agreement (NOA) as required under the SPP Regional OATT, in substantially the form set forth in Exhibit B to this Stipulation.

Section 7. Agreement with Respect to the NITSA

The Signatories acknowledge that:

a. SPS and the SPP shall enter into a NITSA in substantially the form set forth in Exhibit A to this Stipulation. Although not meant to be exhaustive, the following areas are SPP rates, terms, and conditions that may apply to SPS: (1) SPP administrative charges (SPP Schedule 1); (2) ancillary services charges (SPP Schedule 2); (3) charges related to SPP cost allocation for transmission upgrades required for reliability purposes (to maintain compliance with NERC and other applicable reliability standards); (4) charges related to SPP cost allocation for transmission upgrades required for purposes other than to meet reliability requirements that are determined through SPP planning processes; (5) costs and revenues related to the operation of the SPP EIS Market; (6) allocation of SPP FERC assessment fees (SPP Schedule 12); and (7) charges for ancillary services not self-provided by SPS. However, the Commission is not bound to automatically pass through any of these wholesale transmission costs into the transmission component of the bundled rate paid by New Mexico retail customers.

b. SPS agrees, and the SPP acknowledges, that the Commission's approval of SPS's participation in the SPP is subject to the condition that the NITSA will be accepted for filing or approval by the FERC. SPS and the SPP will agree to promptly execute the NITSA and NOA and the SPP will promptly file the NITSA and NOA with the FERC following the approval of this Stipulation by the Commission. If the Commission approves the Stipulation and if the FERC unconditionally accepts SPP's filings, no further proceeding before the Commission with regard to the NITSA to serve SPS retail load in New Mexico will be required.

c. The execution and implementation of the NITSA to serve SPS retail load in New Mexico effective January 1, 2010, is necessary for SPS to fulfill its requirement as a member of the SPP pursuant to Sections 1.44a and 38.2 of the SPP Regional OATT, and, therefore, is an integral part of this Stipulation.

Section 8. Continued Rate Authority

SPS owns and operates integrated transmission facilities in New Mexico, Texas, Oklahoma, and Kansas for the benefit of its customers, including, but not limited to, its New Mexico retail customers. SPS acknowledges that the Commission has, and will continue to have, authority to determine the just and reasonable level, and set the transmission component, of SPS's bundled retail rates to serve its New Mexico retail customers related to SPS transmission facilities.

a. While the Signatories acknowledge that – as a member of SPP – SPS is required by SPP to transfer its retail load to transmission services under the SPP OATT, nothing in this Stipulation shall be construed as implying that the Commission is bound to automatically pass through the resulting wholesale transmission costs into the transmission component of the bundled rates paid by New Mexico retail customers. The Signatories acknowledge that FERC has, and will continue to have, authority to determine the just and reasonable rates for third-party wholesale transmission services in interstate commerce (including, but not limited to, services under the SPP Regional OATT) SPS may purchase and seek to include in SPS's bundled retail rates to serve its retail load in New Mexico.

b. SPS agrees the Commission will have the right to rescind its interim approval of SPS's participation in the SPP RTO and to require SPS to timely initiate any notices, filings, and actions necessary to seek withdrawal from the SPP RTO if: (1) FERC issues an order or adopts a final rule or regulation, binding on SPS, that has the effect of precluding the Commission from continuing to set the transmission component of SPS's rates to serve its New Mexico bundled retail load as provided in this Section 8; or (2) the FERC issues an order or adopts a final rule or regulation, binding on SPS, that has the effect of amending, modifying, changing, or abrogating in any material respect any term or condition of the NITSA and such change has a detrimental effect on SPS's New Mexico retail customers. SPS and the SPP agree to notify the Commission and the parties to this proceeding within 60 days of issuance of any FERC order, rule, or regulation amending, modifying, changing, or abrogating any term or condition of the NITSA.

Section 9. Authority of Commission to Order Transmission or Associated Substation Construction or Upgrades

SPS and the SPP acknowledge that if the Commission orders SPS to construct or upgrade transmission lines or substation facilities, SPS and the SPP will work to ensure that the ordered construction or upgrade is accomplished in a timely manner and the progress of construction is reported monthly to the Commission (or such other periodic reporting as may be ordered by the Commission).

Section 10. Agreement to Seek Prior Commission Approval of Transmission Line and Associated Substation Construction or Upgrades in SPS's New Mexico Service Territory

SPS and the SPP shall comply with applicable New Mexico laws and regulations governing authorization to construct or operate transmission lines and associated facilities in SPS's New Mexico service area, or upgrades of transmission lines and associated facilities in such service area, and applicable location approval of those facilities, Sections 62-9-1, 62-9-3, and 62-9-6 NMSA 1978. This commitment shall apply regardless of the purpose for which the transmission line or substation is being constructed or upgraded.

Section 11. Annual Report

On or before June 1 of each year SPS shall file with the Commission, and serve on the parties to this case, a report showing: (a) the SPP administrative charges (SPP Schedule 1) for the prior calendar year; (b) the ancillary services charges (SPP Schedule 2) reimbursed to SPS for the prior calendar year; (c) the charges related to SPP cost allocation for transmission upgrades required for reliability purposes (to maintain compliance with NERC and other applicable reliability standards) during the prior calendar year; (d) the charges related to SPP cost allocation for transmission upgrades required for purposes other than to meet reliability requirements that are determined through SPP planning processes assessed to SPS for the prior calendar year (Schedule 11); (g) costs and revenues related to the operation of the SPP EIS Market for the prior calendar year; (h) allocation of SPP FERC assessment fees (SPP Schedule 12) for the prior calendar year; and (i) the charges from SPP to SPS for ancillary services not self-provided by SPS for the prior calendar year.

SPS and SPP agree that they will respond in good faith within 20 days to any information requests concerning the subject material of the report submitted by parties to this Stipulation within 90 days of the report, including the basis for the Schedule 11 charges.

Section 12. Continued Control Over Transmission Facilities

SPS shall have the obligation to operate transmission facilities in New Mexico to: (a) protect public safety and the safety of its workers, prevent damage to equipment, and preserve reliability in compliance with NERC and regional standards; and (b) as necessary to preserve its right, duties, and obligations regarding electric service to its retail and firm wholesale customers in New Mexico pursuant to state law and consistent with NERC standards.[2] SPS and the SPP commit that SPS's New Mexico retail load will have the highest priority (equal to that of other network retail and firm wholesale customers of SPS) with respect to transmission priority on SPS's transmission facilities.

Section 13. Participation in the SPP Energy Imbalance Service Market; Other Markets

The Signatories agree that SPS will participate in the SPP's EIS market. SPS's participation in the SPP EIS market will be subject to Commission review in relation to New Mexico retail ratemaking treatment of the cost of EIS energy. Energy purchases from SPP in the EIS market shall be subject to the same regulatory standards as other fuel and energy purchases regarding rate recovery.

SPS will notify the Commission and the parties to this proceeding if SPS proposes to participate in any additional markets beyond the EIS. The SPP will notify the Commission and the parties to this proceeding if the SPP proposes to modify the SPP Regional OATT to begin

2 The NERC Standards, TOP-001, contain the following language in this regard:

> R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

providing additional market services by notice of filing pursuant to 18 CFR 35.13. Notices pursuant to this section may be provided electronically by email.

Section 14. FERC Transmission Incentives

SPS recognizes that the Commission currently has the sole regulatory authority to determine whether or not incentives such as those contemplated by FERC Order 679 *et al.*[3] (in which the FERC allowed utilities to request certain incentives for investment in new transmission, investment in new transmission technologies, improvements in the operation of transmission facilities, and participation in a Transco[4] or a Transmission Organization[5]) related to SPS's transmission facilities should be included in rates for SPS's retail customers in New Mexico. The Signatories recognize that FERC has the sole regulatory authority to determine whether Order No. 679 incentives may be included in SPS or SPP wholesale OATT rates.

Section 15. SPP's Assurance of Intervention, Cooperation and Responsiveness.

Nothing in this Section shall: 1) constitute any party's agreement regarding SPP's jurisdictional status; 2) constitute a Commission finding regarding SPP's jurisdictional status; 3) preclude the Commission from investigating SPP's jurisdictional status in other proceedings. The parties reserve all of their rights to address any such issues in future Commission proceedings. Nothing in this Section shall determine in any respect any existing authority that the Commission possesses under New Mexico laws and regulations over the rates and service operations of SPS or SPP and over the approval of construction and siting of facilities necessary to deliver power to SPS's customers. The agreements contained in this Section are intended to allow the Commission to continue to ensure that SPS's cost of providing services to its New

3 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006); *order on reh'g* Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007); *order on reh'g* Order No. 679-B, 119 FERC ¶ 61,062 (2007).

4 In Docket No. RM06-4-000, FERC defines a Transco to mean "a stand-alone transmission company that has been approved by the Commission" that is "engaged solely in selling transmission at wholesale or on an unbundled retail basis."

5 In Docket No. RM06-4-000, FERC defines a Transmission Organization to mean "a regional transmission organization (RTO), independent system operator (ISO), independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities."

Mexico customers is reasonable and the facilities necessary for delivery of power are adequate.

Subject to these reservations SPP agrees:

a. For the Interim Period and thereafter, unless the Commission orders otherwise, SPP agrees:

1. To study, at the request of the Commission or its Staff, any issues of cost and adequacy of transmission service in the SPP region of New Mexico.

2. To place into the SPP Transmission Planning process any requests from SPS to construct upgrades directed by the Commission;

3. To intervene as a party in any Commission proceeding related to SPS's transmission facilities (either new or existing), including but not limited to CCN and other transmission proceedings;

4. To intervene as a party at the request of the Commission, its Staff or SPS, in Commission proceedings, in which the Commission or its Staff desire information regarding SPP related activities or functions and in proceedings in which SPP can provide information useful to the Commission in its decision-making processes;

5. Prior to SPP's Board of Directors' consideration and vote on SPP's annual Transmission Expansion Plan (STEP), any Balanced Portfolio proposals or any other similar regional multi-project transmission proposal, SPP will provide the transmission plans to the Commission or its Staff and, upon request, will meet either in person or via teleconference with the Commission or its Staff and other interested parties to discuss the plans;

6. To provide information to the Commission or its Staff outside of formal Commission proceedings regarding matters identified by the Commission or its Staff to include transmission-related or wholesale market-related matters;

7. To meet at least annually with New Mexico stakeholders, including Commission Staff, retail customers and the electric cooperatives served by any facilities subject to SPP control, administration and management, to discuss SPP and SPS transmission activities in New Mexico;

8. To provide regular updates to the Commission and its Staff, either formally or informally, on matters identified by the Commission or its Staff; and

9. To provide notice to the Commission and its Staff of the commencement of all SPP dockets before the FERC, and, upon reasonable notice and request by the

Commission or its Staff, SPP shall meet with the Commission or its Staff either in person or via teleconference to discuss the matters at issue in the docket.

b. At the end of the Interim Period, the Signatories will review the arrangements in this ~~Section and determine if any modifications by the Commission are necessary.~~

Section 16. Effect of Commissioners' or Staff's Participation in SPP Process

SPS and the SPP agree that they will not claim that participation by any NMPRC Commissioner(s) or Staff in the SPP stakeholder processes constitutes approval or waiver of the need for any NMPRC approvals described in this Stipulation.

Section 17. Compliance with New Mexico Law

SPS will not take any action or do any other thing with respect to rates, charges, terms, or conditions of service, the resolution of disputes under a SPP Membership Agreement or any other matter regarding its obligations and performance requirements under a SPP Membership Agreement that: (a) SPS is not permitted by New Mexico law or regulation to undertake; (b) is prohibited in whole or in part by any New Mexico law or regulation applicable to SPS; or (c) would require SPS to violate a provision of New Mexico law or regulation to comply with its SPP Membership Agreement. Determination of compliance with and permissible action, conduct, and obligations under this section by SPS shall be within the sole jurisdiction of the Commission, subject to applicable state of New Mexico court review. SPS shall not object to SPP's participation in any state proceeding that impacts SPS's ability to perform under a Membership Agreement.

Section 18. Obligation to Actively Support this Stipulation

The Signatories agree that they will support this Stipulation before the Commission.

Section 19. Admission of SPS's Prefiled Testimony and Other Filings into Record

The Signatories stipulate to the admission into the case record of SPS's pre-filed and supplemental testimony and exhibits, SPS Filings and the other parties' filings in the case, and SPS's and Staff's testimony filed in support of the Stipulation, together with all errata and updates.

Section 20. Effect of Approval on Future SPP Rules or Regulations

SPS agrees that the NMPRC's approval in this case will not be deemed to be approval of any future SPP rule or regulation that would abrogate the need for the approvals set forth above.

Section 21. Effect of Modification of Stipulation

There are no third party beneficiaries of this agreement. Although this Stipulation represents a settlement among the parties with respect to the issues presented in this docket, this agreement is merely a settlement proposal submitted to the Commission, which has the authority to enter an order resolving these issues. The Signatories agree that this Stipulation resolves issues only with respect to the New Mexico retail jurisdiction and shall not be binding on or have an effect on proceedings in other SPS jurisdictions.

This Stipulation has been drafted by all the Signatories and is the result of negotiation, compromise, settlement, and accommodation. The Signatories agree that this settlement is in the public interest. The Signatories agree that the terms and conditions herein are interdependent. The various provisions of this Stipulation are not severable. None of the provisions of this Stipulation shall become fully operative unless the Commission shall have entered a final order approving this Stipulation. If the Commission issues a final order inconsistent with the terms of this Stipulation, each Signatory has the right to withdraw from this Stipulation, to submit testimony, and to obtain a hearing and advocate any position it deems appropriate with respect to any issue in this Stipulation.

Section 22. Effect of Stipulation in Other Jurisdictions.

This Stipulation is binding on each of the Signatories only for the purpose of settling the issues as set forth herein in this jurisdiction only and for no other purposes. The matters resolved herein are resolved on the basis of a compromise and settlement. Except to the extent that this Stipulation expressly governs a Signatory's rights and obligations for future periods, this Stipulation shall not be binding or precedential on a Signatory outside of this jurisdiction, or a proceeding to enforce the terms of this Stipulation. It is acknowledged that a Signatory's support of the matters contained in this Stipulation may differ from the position taken or testimony presented by it in other jurisdictions. To the extent that there is a difference, a Signatory does not waive its position in any of those other jurisdictions. Because this is a stipulated resolution, no Signatory is under any obligation to take the same positions as set out in this Stipulation in other jurisdictions, regardless of whether such proceedings in other jurisdictions present the same or a different set of circumstances, except as otherwise may be explicitly provided by this Stipulation.

The provisions of this Stipulation are intended to relate to only the specific matters referred to herein. By agreeing to this Stipulation, no Signatory waives any claim it may otherwise have with respect to issues not expressly provided for herein. It is further understood and agreed that this Stipulation represents a negotiated compromise and settlement of all issues in this proceeding.

This settlement represented by this Stipulation resolves the stated issues in the New Mexico retail jurisdiction only, and this Stipulation does not resolve any claims, issues or proceedings pending in or pertaining to other jurisdictions.

Section 22. Multiple Counterparts

Each copy of this Stipulation may not bear the signatures of all the Signatories but will be deemed fully executed if all copies together bear the signatures of all Signatories.

Fully and duly authorized representatives of the Signatories have signed this Stipulation as of the date first set forth above.

SOUTHWESTERN PUBLIC SERVICE COMPANY

By: ______________________
Jeffrey L. Fornaciari
Attorney of Record

STAFF OF THE NEW MEXICO PUBLIC REGULATION COMMISSION

By: ______________________
Dahl L. Harris
Attorney of Record

ATTORNEY GENERAL OF THE STATE OF NEW MEXICO

By: ______________________
Jeff Taylor
Attorney of Record

CENTRAL VALLEY ELECTRIC COOPERATIVE, INC.;
FARMERS' ELECTRIC COOPERATIVE, INC.;
LEA COUNTY ELECTRIC COOPERATIVE, INC. AND
ROOSEVELT COUNTY ELECTRIC COOPERATIVE, INC.

By: Daniel A. Najjar
Daniel A. Najjar
Attorney of Record

SOUTHWEST POWER POOL, INC.

By: ______________________________
Stacy Duckett, General Counsel
Attorney of Record

CENTRAL VALLEY ELECTRIC
COOPERATIVE, INC.;
FARMERS' ELECTRIC COOPERATIVE, INC.;
LEA COUNTY ELECTRIC COOPERATIVE,
INC. AND
ROOSEVELT COUNTY ELECTRIC
COOPERATIVE, INC.

By: ______________________________
Daniel A. Najjar
Attorney of Record

SOUTHWEST POWER POOL, INC.

By: ______________________________
Stacy Duckett, General Counsel
Attorney of Record

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF AN INVESTIGATION INTO THE PRUDENCE OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S PARTICIPATION IN THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION	
	Case No. 07-00390-UT
SOUTHWESTERN PUBLIC SERVICE COMPANY,	
Respondent	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the *Uncontested Stipulation* were electronically communicated, and sent by Federal Express, United States Mail, or hand-delivered, as indicated below, to the following on this 17th day of September, 2009:

Sent via Federal Express to:

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Respectfully submitted,

HINKLE, HENSLEY, SHANOR & MARTIN L.L.P.

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Post Office Box 2068
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Attorneys for Southwestern Public Service Company

Exhibit A

Proposed

Service Agreement For Network Integration Transmission Service

This Network Integration Service Agreement ("Service Agreement") is entered into this ____ day of __________, 2009, by and between Southwestern Public Service Company ("Network Customer "), and Southwest Power Pool, Inc. ("Transmission Provider"). The Network Customer and Transmission Provider shall be referred to individually as "Party" and collectively as "Parties."

WHEREAS, the Transmission Provider has determined that the Network Customer has made a valid request for Network Integration Transmission Service in accordance with the Transmission Provider's Open Access Transmission Tariff ("Tariff") filed with the Federal Energy Regulatory Commission ("Commission") as it may from time to time be amended;

WHEREAS, the Transmission Provider administers Network Integration Transmission Service for Transmission Owners within the Southwest Power Pool and acts as agent for the Transmission Owners in providing service under the Tariff; and

WHEREAS, the Network Customer has represented that it is an Eligible Customer under the Tariff;

Whereas, the Parties intend that capitalized terms used herein shall have the same meaning as in the Tariff.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein, the Parties agree as follows:

1.0 The Transmission Provider agrees during the term of this Service Agreement, as it may be amended from time to time, to provide Network Integration Transmission Service in accordance with the Tariff to enable delivery of power and energy from the Network Customer's Network Resources that the Network Customer has committed to meet its load.

2.0 The Network Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Parts I, III and V of the Tariff and this Service Agreement with the specifications of the Unanimous Stipulation in New Mexico Public Regulation Commission Case No. 07-00390-UT, *et. al.*.

3.0 The terms and conditions of such Network Integration Transmission Service shall be governed by the Tariff, as in effect at the time this Service Agreement is executed by the Network Customer, or as the Tariff is thereafter amended or by its successor tariff, if any. The Tariff as it currently exists, or as it is hereafter amended is incorporated in this Service Agreement by reference. In the case of any conflict between this Service Agreement and the Tariff, the Tariff shall control. The Network Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff. The completed specifications are based on the information provided in the Completed Application and are incorporated herein and made a part hereof as Attachment 1.

4.0 Service under this Service Agreement shall commence on such date as it is permitted to become effective by the Commission. This Service Agreement shall be effective through December 31, 2014. Thereafter, it will continue from year to year unless terminated by the Network Customer or the Transmission Provider by giving the other one-year advance written notice or by the mutual written consent of the Transmission Provider and

Network Customer. Upon termination, the Network Customer remains responsible for any outstanding charges including all costs incurred and apportioned or assigned to the Network Customer under this Service Agreement.

5.0 The Transmission Provider and Network Customer have executed a Network Operating Agreement as required by the Tariff.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party or the other.

Southwest Power Pool:

____

415 N. McKinley, 140 Plaza West
Little Rock, AR 72205

Network Customer: President & CEO
600 S. Tyler St, Suite 2900
Amarillo, TX 79010

7.0 This Service Agreement shall not be assigned by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld. However, either Party may, without the need for consent from the other, transfer or assign this Service Agreement to any person succeeding to all or substantially all of the assets of such Party. However, the assignee shall be bound by the terms and conditions of this Service Agreement.

8.0 Nothing contained herein shall be construed as affecting in any way the Transmission Provider's or a Transmission Owner's right to unilaterally make application to the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, for any change in the Tariff or this Service Agreement under Section 205 of the Federal Power Act, or other applicable statute, and any rules and regulations promulgated thereunder; or the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

9.0 By signing below, the Network Customer verifies that all information submitted to the Transmission Provider to provide service under the Tariff is complete, valid and accurate, and the Transmission Provider may rely upon such information to fulfill its responsibilities under the Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

TRANSMISSION PROVIDER	NETWORK CUSTOMER
Name ____________________	Name ____________________
Title ____________________	Title ____________________
Date ____________________	Date ____________________

ATTACHMENT 1 TO THE NETWORK INTEGRATION TRANSMISSION SERVICE AGREEMENT
BETWEEN SOUTHWEST POWER POOL AND SOUTHWESTERN PUBLIC SERVICE COMAPNY
SPECIFICATIONS FOR NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 Network Resources

The Network Resources are listed in Appendix 1.

2.0 Network Loads

The Network Load consists of the bundled native load or its equivalent for Network Customer load in the Southwestern Public Service Company (SPS) Control Area. Network Customer delivery points are as metered at its generation and transmission interconnection points.

The Network Customer's Network Load shall be measured on an hourly integrated basis, by suitable metering equipment located at each connection and delivery point, and each generating facility. For a Network Customer providing retail electric service pursuant to a state retail access program, profiled demand data, based upon revenue quality non-IDR meters may be substituted for hourly integrated demand data. Measurements taken and all metering equipment shall be in accordance with the Transmission Provider's standards and practices for similarly determining the Transmission Provider's load. The actual hourly network Loads, by delivery point, internal generation site and point where power may flow to and from the Network Customer, with separate readings for each direction of flow, shall be provided.

3.0 Affected Control Areas and Intervening Systems Providing Transmission Service

The affected control area is SPS. The intervening systems providing transmission service are SPS.

4.0 Electrical Location of Initial Sources

See Appendix 1.

5.0 Electrical Location of the Ultimate Loads

The loads of SPS identified in Section 2.0 hereof as the Network Load are electrically located within the SPS Control Area.

6.0 Delivery Points

The delivery points are the interconnection points of SPS identified in Section 2.0 as the Network Load.

7.0 Receipt Points

The Points of Receipt are listed in Appendix 2.

8.0 Compensation

Service under this Service Agreement may be subject to some combination of the charges detailed below. The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.

8.1 **Transmission Charge**

Monthly Demand Charge per Section 34 and Part V of the Tariff.

8.2 **System Impact and/or Facility Study Charge**

Studies may be required in the future to assess the need for system reinforcements in light of the ten-year forecast data provided. Future charges, if required, shall be in accordance with Section 32 of the Tariff.

8.3 **Direct Assignment Facilities Charge**

8.4 **Ancillary Service Charges**

8.4.1 The following Ancillary Services are required under this Service Agreement.

a) Scheduling and Tariff Administration Service per Schedule 1A of the Tariff.

b) Scheduling. System Control and Dispatch Service per Schedule 1 of the Tariff.

c) Reactive Supply and Voltage Control from Generation Sources Service per Schedule 2 of the Tariff.

d) Regulation and Frequency Response Service per Schedule 3 of the Tariff.

e) Energy Imbalance Service per Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service per Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service per Schedule 6 of the Tariff.

The Ancillary Services will be self-supplied by the Network Customer in accordance with Sections 8.4.2 through 8.4.4, with the exception of the Ancillary Services for Schedules 1 and 2.

8.4.2 With its annual forecasts, the Network Customer shall indicate its source for Ancillary Services in accordance with the Tariff to be in effect for the upcoming calendar year. If the Network Customer fails to include this information with its annual forecasts, Ancillary Services will be provided for and charged in accordance with the Tariff.

8.4.3 When the Network Customer elects to self provide Ancillary Services and is unable to provide its own Ancillary Services, the Network Customer will pay the Transmission Provider for such services and associated penalties in accordance with the Tariff as a result of the failure of the Network Customer's alternate sources for required Ancillary Services.

8.4.4 All costs for the Network Customer to supply its own Ancillary Services shall be the responsibility of the Network Customer.

8.5 Real Power Losses

The Network Customer shall replace losses in accordance with Attachment M of the Tariff.

8.6 Power Factor Correction Charge

8.7 Redispatch Charge

Redispatch charges shall be in accordance with Section 33.3 of the Tariff.

8.8 Wholesale Distribution Service Charge

8.9 Network Upgrade Charges

8.10 Other Charges

9.0 Credit for Network Customer-Owned Transmission Facilities

10.0 Designation of Parties Subject to Reciprocal Service Obligation

11.0 Other Terms and Conditions

APPENDIX 1

Network Resources of SPS

APPENDIX 1 SPS NETWORK RESOURCES

		Maximum Net Dependable Capacity		
	Network Resource	Summer	Winter	Location
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				

19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				

Appendix 2

Receipt Points of

SPS to serve SPS New Mexico Retail Consumers

APPENDIX 2 SPS NEW MEXICO RETAIL RECEIPT POINTS

Tieline / Plant Name	Ownership	Voltage (kV)	Rating (MVA)

Exhibit B

Proposed Network Operating Agreement

This Network Operating Agreement ("Operating Agreement") is entered into this ____ day of __________, ____, by and between ______________ ("Network Customer"), Southwest Power Pool, Inc. ("Transmission Provider") and __________ ("Host Transmission Owner"). The Network Customer, Transmission Provider and Host Transmission Owner shall be referred to as "Parties."

WHEREAS, the Transmission Provider has determined that the Network Customer has made a valid request for Network Integration Transmission Service in accordance with the Transmission Provider's Open Access Transmission Tariff ("Tariff") filed with the Federal Energy Regulatory Commission ("Commission");

WHEREAS, the Transmission Provider administers Network Integration Transmission Service for Transmission Owners within the Southwest Power Pool and acts as an agent for these Transmission Owners in providing service under the Tariff;

WHEREAS, the Host Transmission Owner owns the transmission facilities to which the Network Customer's Network Load is physically connected or is the Control Area to which the Network Load is dynamically scheduled;

WHEREAS, the Network Customer has represented that it is an Eligible Customer under the Tariff;

WHEREAS, the Network Customer and Transmission Provider have entered into a Network Integration Transmission Service Agreement ("Service Agreement")under the Tariff; and

WHEREAS, the Parties intend that capitalized terms used herein shall have the same meaning as in the Tariff unless otherwise specified herein;

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein, the Parties agree as follows:

1.0 Network Service

This Operating Agreement sets out the terms and conditions under which the Transmission Provider, Host Transmission Owner, and Network Customer will cooperate and the Host Transmission Owner and Network Customer will operate their respective systems and specifies the equipment that will be installed and operated. The Parties shall operate and maintain their respective systems in a manner that will allow the Host Transmission Owner and the Network Customer to operate their systems and Control Area and the Transmission Provider to perform its obligations consistent with Good Utility Practice. The Transmission Provider may, on a non-discriminatory basis, waive the requirements of Section 4.1 and Section 8.3 to the extent that such information is unknown at the time of application or where such requirement is not applicable.

2.0 Designated Representatives of the Parties

2.1 Each Party shall designate a representative and alternate ("Designated Representative(s)") from their respective company to coordinate and implement, on an ongoing basis, the terms and conditions of this Operating Agreement, including planning, operating, scheduling, redispatching, curtailments, control requirements, technical and operating provisions, integration of equipment, hardware and software, and other operating considerations.

2.2 The Designated Representatives shall represent the Transmission Provider, Host Transmission Owner, and Network Customer in all matters arising under this Operating Agreement and which may be delegated to them by mutual agreement of the Parties hereto.

2.3 The Designated Representatives shall meet or otherwise confer at the request of any Party upon reasonable notice, and each Party may place items on the meeting agenda. All deliberations of the Designated Representatives shall be conducted by taking into account the exercise of Good Utility Practice. If the Designated Representatives are unable to agree on any matter subject to their deliberation, that matter shall be resolved pursuant to Section 12.0 of the Tariff, or otherwise, as mutually agreed by the Network Customer, Host Transmission Owner, and Transmission Provider.

3.0 System Operating Principles

3.1 The Network Customer must design, construct, and operate its facilities safely and efficiently in accordance with Good Utility Practice, NERC, SPP, or any successor requirements, industry standards, criteria, and applicable manufacturer's equipment specifications, and within operating physical parameter ranges (voltage schedule, load power factor, and other parameters) required by the Host Transmission Owner and Transmission Provider.

3.2 The Host Transmission Owner and Transmission Provider reserve the right to inspect the facilities and operating records of the Network Customer upon mutually agreeable terms and conditions.

3.3 Electric service, in the form of three phase, approximately sixty hertz alternating current, shall be delivered at designated delivery points and nominal voltage(s) listed in the Service Agreement. When multiple delivery points are provided to a specific Network Load identified in Appendix 2 to the Service Agreement, they shall not be operated in parallel by the Network Customer without the approval of the Host Transmission Owner and Transmission Provider. The Designated Representatives shall establish the procedure for obtaining such approval. It shall also establish and monitor standards and operating rules and procedures to assure that transmission system integrity and the safety of customer, the public and employees are maintained or enhanced when such parallel operations is permitted either on a continuing basis or for intermittent switching or other service needs. Each Party shall exercise due diligence and reasonable care in maintaining and operating its facilities so as to maintain continuity of service.

3.4 The Host Transmission Owner and Network Customer shall operate their systems and delivery points in continuous synchronism and in accord with applicable NERC Standards and SPP Criteria and Good Utility Practice.

3.5 If the function of any Party's facilities is impaired or the capacity of any delivery point is reduced, or synchronous operation at any delivery point(s) becomes interrupted, either manually or automatically, as a result of force majeure or maintenance coordinated by the Parties, the Parties will cooperate to remove the cause of such impairment, interruption or reduction, so as to restore normal operating conditions expeditiously.

3.6 The Transmission Provider and Host Transmission Owner, if applicable, reserve the sole right to take any action necessary during an actual or imminent emergency to preserve the reliability and integrity of the Transmission System, limit or prevent damage, expedite restoration of service, ensure safe and reliable operation, avoid adverse effects on the quality of service, or preserve public safety.

3.7 In an emergency, the reasonable judgment of the Transmission Provider and Host Transmission Owner, if applicable, in accordance with Good Utility Practice, shall be the sole determinant of whether the operation of the Network Customer loads or equipment adversely affects the quality of service or interferes with the safe and reliable operation of the transmission system. The Transmission Provider or Host Transmission Owner, if applicable, may discontinue transmission service to such Network Customer until the power quality or interfering condition has been corrected. Such curtailment of load, redispatching, or load shedding shall be done on a non-discriminatory basis by Load Ratio Share, to the extent practicable. The Transmission Provider or Host Transmission Owner, if applicable, will provide reasonable notice and an opportunity to alleviate the condition by the Network Customer to the extent practicable.

4.0 System Planning & Protection

4.1 No later than October 1 of each year, the Network Customer shall provide the Transmission Provider and Host Transmission Owner the following information:

a) A ten (10) year projection of summer and winter peak demands with the corresponding power factors and annual energy requirements on an aggregate basis for each delivery point. If there is more than one delivery point, the Network Customer shall provide the summer and winter peak demands and energy requirements at each delivery point for the normal operating configuration;

b) A ten (10) year projection by summer and winter peak of planned generating capabilities and committed transactions with third parties which resources are expected to be used by the Network Customer to supply the peak demand and energy requirements provided in (a);

c) A ten (10) year projection by summer and winter peak of the estimated maximum demand in kilowatts that the Network Customer plans to acquire from the generation resources owned by the Network Customer, and generation resources purchased from others; and

d) A projection for each of the next ten (10) years of transmission facility additions to be owned and/or constructed by the Network Customer which facilities are expected to affect the planning and operation of the transmission system within the Host Transmission Owner's control area.

This information is to be delivered to the Transmission Provider's and Host Transmission Owner's Designated Representatives pursuant to Section 2.0.

4.2 Information exchanged by the Parties under this article will be used for system planning and protection only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency.

4.3 The Host Transmission Owner, and Transmission Provider, if applicable, will incorporate this information in its system load flow analyses performed during the first half of each year. Following completion of these analyses, the Transmission Provider or Host Transmission Owner will provide the following to the Network Customer:

a) A statement regarding the ability of the Host Transmission Owner's transmission system to meet the forecasted deliveries at each of the delivery points;

b) A detailed description of any constraints on the Host Transmission Owner's system within the five (5) year horizon that will restrict forecasted deliveries; and

c) In the event that studies reveal a potential limitation of the Transmission Provider's ability to deliver power and energy to any of the delivery points, a Designated Representative of the Transmission Provider will coordinate with the Designated Representatives of the Host Transmission Owner and the Network Customer to identify appropriate remedies for such constraints including but not limited to: construction of new transmission facilities, upgrade or other improvements to existing transmission facilities or temporary modification to operating procedures designed to relieve identified constraints. Any constraints within the Transmission System will be remedied pursuant to the procedures of Attachment O of the Tariff.

For all other constraints the Host Transmission Owner, upon agreement with the Network Customer and consistent with good utility practice, will endeavor to construct and place into service sufficient capacity to maintain reliable service to the Network Customer.

An appropriate sharing of the costs to relieve such constraints will be determined by the Parties, consistent with the Tariff and with the Commission's rules, regulations, policies, and precedents then in effect. If the Parties are unable to agree upon an appropriate remedy or sharing of the costs, the Transmission Provider shall submit its proposal for the remedy or sharing of such costs to The Commission for approval consistent with the Tariff.

4.4 The Host Transmission Owner and the Network Customer shall coordinate with the Transmission Provider: (1) all scheduled outages of generating resources and transmission facilities consistent with the reliability of service to the customers of each Party, and (2) additions or changes in facilities which could affect another Party's system. Where coordination cannot be achieved, the Designated Representatives shall intervene for resolution.

4.5 The Network Customer shall coordinate with the Host Transmission Owner regarding the technical and engineering arrangements for the delivery points, including one line diagrams depicting the electrical facilities configuration and parallel generation, and shall design and build the facilities to avoid interruptions on the Host Transmission Owner's transmission system.

4.6 The Network Customer shall provide for automatic and underfrequency load shedding of the Network Customer Network Load in accordance with the SPP Criteria related to emergency operations.

5.0 Maintenance of Facilities

5.1 The Network Customer shall maintain its facilities necessary to reliably receive capacity and energy from the Host Transmission Owner's transmission system consistent with Good Utility Practice. The Transmission Provider or Host Transmission Owner, as appropriate, may curtail service under this Operating Agreement to limit or prevent damage to generating or transmission facilities caused by the Network Customer's failure to maintain its facilities in accordance with Good Utility Practice, and the Transmission Provider or Host Transmission Owner may seek as a result any appropriate relief from The Commission.

5.2 The Designated Representatives shall establish procedures to coordinate the maintenance schedules, and return to service, of the generating resources and transmission and substation facilities, to the greatest extent practical, to ensure sufficient transmission resources are available to maintain system reliability and reliability of service.

5.3 The Network Customer shall obtain: (1) concurrence from the Transmission Provider before beginning any scheduled maintenance of facilities which could impact the operation of the transmission system over which transmission service is administered by Transmission Provider; and (2) clearance from the Transmission Provider when the Network Customer is ready to begin maintenance on a transmission line or substation. The Transmission Provider shall coordinate clearances with the Host Transmission Owner. The Network Customer shall notify the Transmission Provider and the Host Transmission Owner as soon as practical at the time when any unscheduled or forced outages occur and again when such unscheduled or forced outages end.

6.0 Scheduling Procedures

6.1 Prior to the beginning of each week, the Network Customer shall provide to the Transmission Provider expected hourly energy schedules for that week for all energy flowing into the transmission system administered by Transmission Provider.

6.2 In accordance with Section 36 of the Tariff, the Network Customer shall provide to the Transmission Provider the Network Customer's hourly energy schedules for the next calendar day for all energy flowing into the transmission system administered by the Transmission Provider. The Network Customer may modify its hourly energy schedules up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving

Party also agree to the schedule modification. The hourly schedule must be stated in increments of 1000 kW per hour. The Network Customer shall submit, or arrange to have submitted, to the Transmission Provider a NERC transaction identification Tag where required by NERC Standard INT-001. These hourly energy schedules shall be used by the Transmission Provider to determine whether any Energy Imbalance Service charges, pursuant to Schedule 4 of the Tariff apply.

7.0 Ancillary Services

7.1 The Network Customer must purchase in appropriate amounts all of the required Ancillary Services described in the Tariff from the Transmission Provider or Host Transmission Owner or, where applicable, self-supply or obtain these services from other providers.

7.2 Where the Network Customer elects to self-supply or have a third party provide Ancillary Services, the Network Customer must demonstrate to the Transmission Provider that it has either acquired the Ancillary Services from another source or is capable of self supplying the services.

7.3 The Network Customer must designate the supplier of Ancillary Services.

8.0 Metering

8.1 The Network Customer shall provide for the installation of meters, associated metering equipment and telemetering equipment. The Network Customer shall permit the Transmission Provider's and Host Transmission Owner's representative to have access to the equipment at all reasonable hours and for any reasonable purpose, and shall not permit unauthorized persons to have access to the space housing the equipment.

8.2 The Network Customer shall provide for the testing of the metering equipment at suitable intervals and its accuracy of registration shall be maintained in accordance with standards acceptable to the Transmission Provider and consistent with Good Utility Practice. At the request of the Transmission Provider or Host Transmission Owner, a special test shall be made, but if less than two percent inaccuracy is found, the requesting party shall pay for the test. Representatives of the Parties may be present at all routine or special tests and whenever any readings for purposes of settlement are taken from meters not having an automated record. If any test of metering equipment discloses an inaccuracy exceeding two percent, the accounts of the parties shall be adjusted. Such adjustment shall apply to the period over which the meter error is shown to have been in effect or, where such period is indeterminable, for one-half the period since the prior meter test. Should any metering equipment fail to register, the amounts of energy delivered shall be estimated from the best available data.

8.3 If the Network Customer is supplying energy to Retail load that has a choice in its supplier, the Network Customer shall be responsible for providing all information required by the Transmission Provider for billing purposes. Metering information shall be available to the Transmission Provider either by individual retail customer or aggregated retail energy information for that load the Network Customer has under contract during the billing month. For the retail load that has interval demand metering, the actual energy used by interval must be supplied. For the retail load using standard kWh metering, the total energy consumed by meter cycle, along with the estimated demand profile must be supplied. All rights and limitations between parties granted in Sections 8.1, and 8.2 are applicable in regards to retail metering used as the basis for billing the Network Customer

9.0 Connected Generation Resources

9.1 The Network Customer's connected generation resources that have automatic generation control (AGC) and automatic voltage regulation (AVR) shall be operated and maintained consistent with regional operating standards, and the Network Customer or the operator shall operate, or cause to be operated, such resources to avoid adverse disturbances or interference with the safe and reliable operation of the transmission system.

9.2 For all Network Resources of the Network Customer, the following generation telemetry readings to the Host Transmission Owner are required:

1) Analog MW
2) Integrated MWHRS/HR
3) Analog MVARS
4) Integrated MVARHRS/HR

10.0 Redispatching, Curtailment and Load Shedding

10.1 In accordance with Section 33 of the Tariff, the Transmission Provider may require redispatching of generation resources or curtailment of loads to relieve existing or potential transmission system constraints. The Network Customer shall submit verifiable incremental and decremental cost data from its Network Resources to the Transmission Provider. These costs will be used as the basis for least-cost redispatch. Information exchanged by the Parties under this article will be used for system redispatch only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency. The Network Customer shall respond immediately to requests for redispatch from the Transmission Provider. The Transmission Provider will bill or credit the Network Customer as appropriate.

10.2 The Parties shall implement load-shedding procedures to maintain the reliability and integrity for the Transmission System as provided in Section 33.1 of the Tariff and in accordance with applicable NERC and SPP requirements and Good Utility Practice. Load shedding may include (1) automatic load shedding, (2) manual load shedding, and (3) rotating interruption of customer load. When manual load shedding or rotating interruptions are necessary, the Host Transmission Owner shall notify the Network Customer's dispatcher or schedulers of the required action and the Network Customer shall comply immediately.

10.3 The Network Customer will coordinate with the Host Transmission Owner to ensure sufficient load shedding equipment is in place on their respective systems to meet SPP requirements. The Network Customer and the Host Transmission Owner shall develop a plan for load shedding which may include manual load shedding by the Network Customer.

11.0 Communications

11.1 The Network Customer shall, at its own expense, install and maintain communication link(s) for scheduling. The Communication link(s) shall be used for data transfer and for voice communication.

11.2 A Network Customer self supplying Ancillary Services or securing Ancillary Services from a third-party shall, at its own expense, install and maintain telemetry equipment communicating between the generating resource(s) providing such ancillary services and the Host Transmission Owner's Control Area.

12.0 Cost Responsibility

12.1 The Network Customer shall be responsible for all costs incurred by the Network Customer, Host Transmission Owner, and Transmission Provider to implement the provisions of this Operating Agreement including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specification, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment or software, so long as the direct assignment of such costs is consistent with Commission policy.

12.2 The Network Customer shall be responsible for all costs incurred by Network Customer, Host Transmission Owner, and Transmission Provider for on-going operation and maintenance of the facilities required to implement the provisions of this Operating Agreement so long as the direct assignment of such costs is consistent with Commission policy. Such work shall include, but is not limited to, normal and extraordinary engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, calibration, removal, or relocation of equipment required to accommodate service provided under this Operating Agreement.

13.0 Billing and Payments

Billing and Payments shall be in accordance with Section 7 of the Tariff.

14.0 Dispute Resolution

Any dispute among the Parties regarding this Operating Agreement shall be resolved pursuant to Section 12 of the Tariff, or otherwise, as mutually agreed by the Parties.

15.0 Assignment

This Operating Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by any Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the other parties. Such written consent shall not be unreasonably withheld.

16.0 Choice of Law

The interpretation, enforcement, and performance of this Operating Agreement shall be governed by the laws of the State of Arkansas, except laws and precedent of such jurisdiction concerning choice of law shall not be applied, except to the extent governed by the laws of the United States of America.

17.0 Entire Agreement

The Tariff and Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof. To the extent that a conflict exists between the terms of this Operating Agreement and the terms of the Tariff, the Tariff shall control.

18.0 Unilateral Changes and Modifications

Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way the right of the Transmission Provider or a Transmission Owner unilaterally to file with the Commission, or make application to the Commission for, changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or under other applicable statutes or regulations.

Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way the ability of any Network Customer receiving Network Transmission Service under this Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder; provided, however, that it is expressly recognized that this Operating Agreement is necessary for the implementation of the Tariff and Service Agreement. Therefore, no Party shall propose a change to this Operating Agreement that is inconsistent with the rates, terms and conditions of the Tariff and/or Service Agreement.

19.0 Term

This Operating Agreement shall become effective on the date assigned by the Commission ("Effective Date"), and shall continue in effect until the Tariff or the Network Customer's Service Agreement is terminated, whichever shall occur first.

20.0 Notice

20.1 Except as herein otherwise provided, any notice that may be given to or made upon any Party by any other Party under any of the provisions of this Operating Agreement shall be in writing unless otherwise specifically provided herein and shall be considered delivered when the notice is personally delivered or deposited in the United States mail, certified or registered postage prepaid, to the following:

Southwest Power Pool

Carl Monroe

Executive Vice President and Chief Operating Officer

415 North McKinley, #140 Plaza West

Little Rock, AR 72205-3020

501/614-3218 Phone

501/664-9553 Fax

[Host Transmission Owner]
[name]
[title]
[address]
[phone]
[fax]

[Network Customer]
[name]
[title]
[address]
[phone]
[fax]

Any Party may change its notice address by written notice to the other Parties in accordance with this Article 20.

20.2 Any notice, request, or demand pertaining to operating matters may be delivered in writing, in person or by first class mail, e-mail, messenger, telegraph, or facsimile transmission as may be appropriate and shall be confirmed in writing as soon as reasonably practical thereafter, if any Party so requests in any particular instance

21.0 Execution in Counterparts

This Operating Agreement may be executed in any number of counterparts with the same effect as if all Parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Operating Agreement to be executed by their respective authorized officials, and copies delivered to each Party, to become effective as of the Effective Date.

TRANSMISSION PROVIDER

____
Name

____
Title

____
Date

HOST TRANSMISSION OWNER

____
Name

____
Title

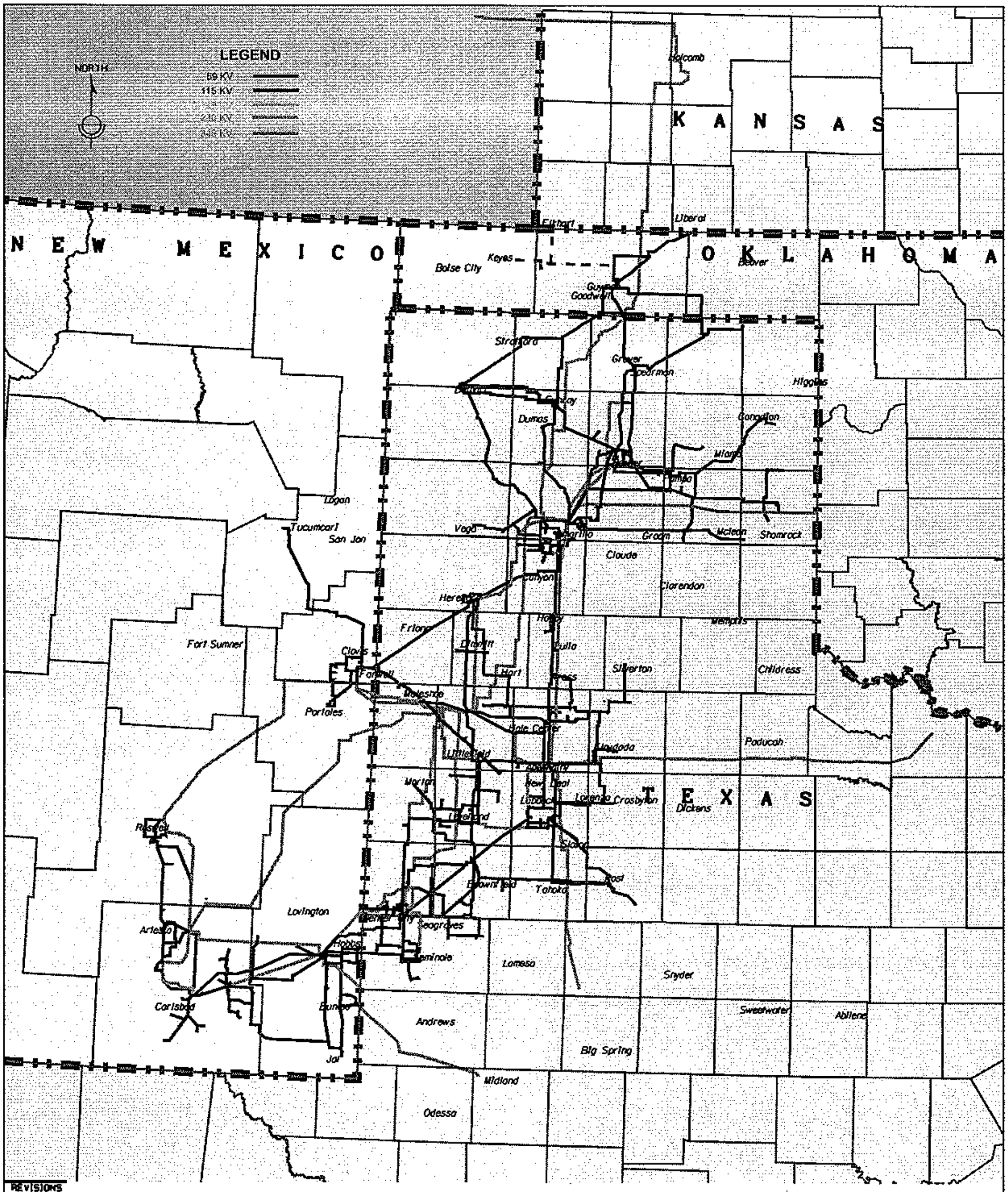
____
Date

NETWORK CUSTOMER

____
Name

____
Title

____
Date

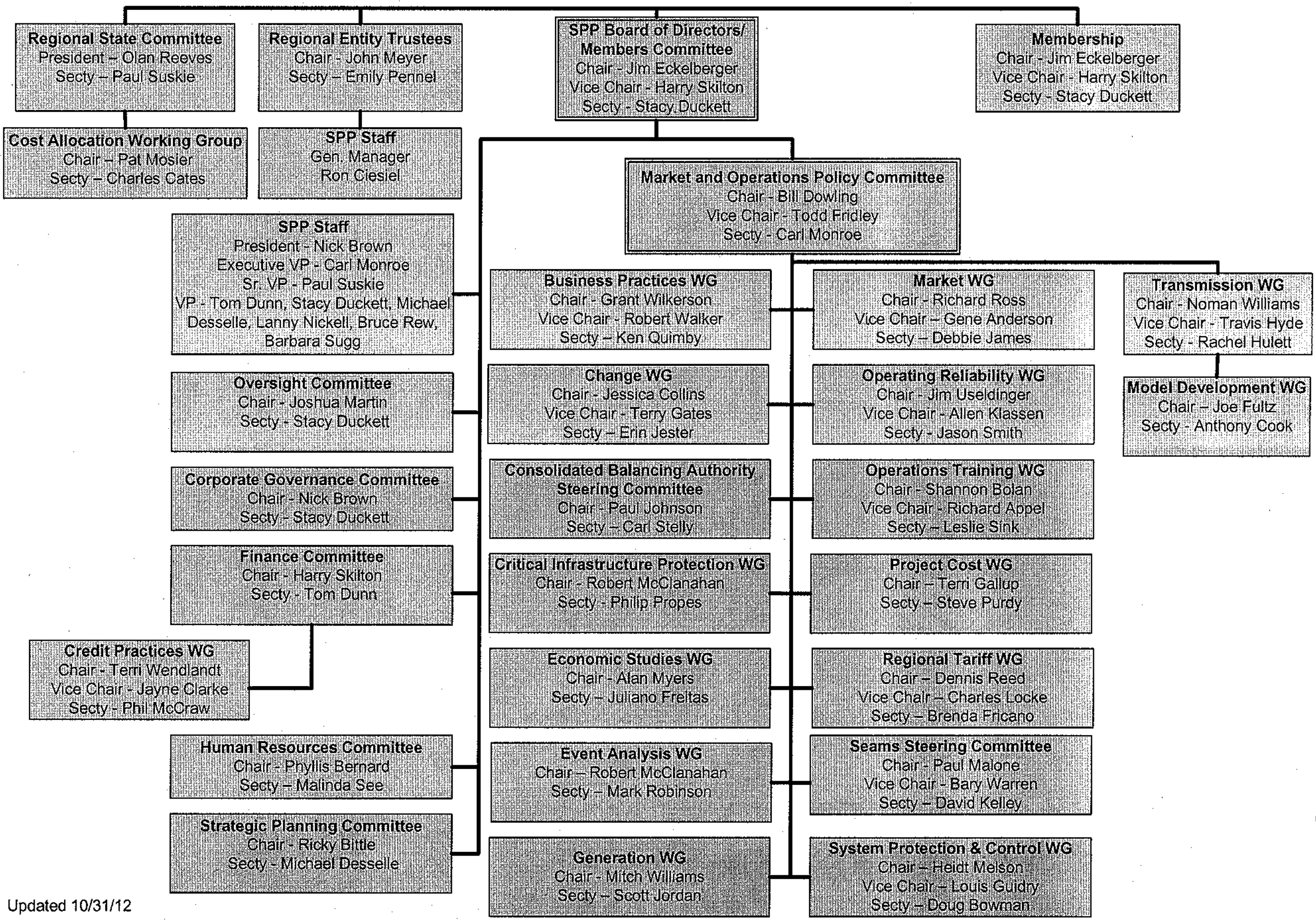


REVISIONS

THIS DRAWING IS THE PROPERTY OF [illegible] AMARILLO, TEXAS AND IS NOT TO BE REPRODUCED OR USED TO FURNISH ANY INFORMATION FOR THE MAKING OF DRAWINGS OR APPARATUS EXCEPT WHERE PROVIDED FOR BY AGREEMENT WITH SAID COMPANY.				DESCRIPTION			
Xcel Energy	DRAWN KSL	DATE 10-26-12	CHECKED	APPROVED	SCALE	ENGINEERING DEPT. SPSASIZE	REV.

Southwest Power Pool

Group Organizational Chart



Updated 10/31/12

Summary of Southwest Power Pool's Cost Allocation Methods

Date Range	Upgrade Type	Zonal	Regional	Customer	Sponsor	Comments
Pre-2005	Pre-BPF Needs	100%				Before Regional Cost Sharing
	Other	100%				
Original Base Plan Funding 2005 - NTC Issue Date of June 19, 2010	Sponsored				100%	
	Reliability	67%	33%			Based on Need-By Date - Zonal on MW-MI beneficiary %
	Generation Interconnection			100%		
	NITS Service Upgrade costs covered by Safe Harbor limit	67%	33%			Zonal on MW-MI
	NITS Service Upgrade costs *NOT* covered by Safe Harbor limit			100%		Safe Harbor Limit: E&C Cost <=$180,000/MW Requested
	PtP Service Upgrade costs *that do not qualify for Base Plan Funding*			100%		costs in excess of access charges
	Balanced Portfolio		100%			
	Sponsored				100%	
NTC Issue Date of June 19, 2010 or later	Reliability/Economic Upgrade Voltage Over 300 kV	0%	100%			
	Reliability/Economic Upgrade Voltage over 100 kV and under 300 kV	67%	33%			
	Reliability/Economic Upgrade Voltage under 100 kV	100%	0%			
	Upgrades related to delivery of power from Wind projects outside TSR Cusomer's Load Zone and less than 300kV		67%	33%		Effective in 2009
	Upgrades related to delivery of power from Wind projects greater than 300kV		100%			
	NITS Service Upgrade costs covered by Safe Harbor limit	*Voltage Dependent:* >300kV=100% Regional, 100kV to 299KV=33% Regional+67% Zonal, >100kV=100% Zonal				"Highway/Byway" method, upgrade >300kV 100% Regional in all cases
	NITS Service Upgrade costs *NOT* covered by Safe Harbor limit or do not qualify for Base Plan Funding			100%		
	PtP Service Upgrade costs that do not qualify for Base Plan			100%		costs excess of access charges
	Generation Interconnection			100%		

Dan Jones, PE
SPP Lead Regulatory Engineer
djones@spp.org
501-688-1717 ofc
501-680-7404 cell

ATTACHMENT J
RECOVERY OF COSTS ASSOCIATED WITH NEW FACILITIES

Effective Date: 7/26/2010 - Docket #: ER10-1960

I. Direct Assignment Facilities

Where a System Impact and/or Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities. Such costs shall be specified in a Service Agreement.

Effective Date: 7/26/2010 - Docket #: ER10-1960

II. Network Upgrades

Where applicable the costs of completed Network Upgrades shall be allocated as specified in Sections III, IV and V of this Attachment. The revenue requirements of Base Plan Upgrades and approved Balanced Portfolios will be recovered through Schedule 11, subject to filing such rate or revenue requirements with the Commission, and where applicable Directly Assigned Upgrade Costs. These costs may be recovered in whole or in part through the Base Plan Zonal Charge, Base Plan Region-wide Charge, and/or a direct assignment charge. The cost allocable to each of these charges shall be determined in accordance with Section III of this Attachment. The revenue requirements for other Network Upgrades may be recovered by Transmission Owners through Schedules 7, 8, and 9 subject to their filing such rate or revenue requirements with the Commission.

Effective Date: 7/26/2010 - Docket #: ER10-1960

III. Base Plan Upgrades

A single Base Plan Upgrade is comprised of any upgrade or group of upgrades required to be made to a single transmission circuit, where a transmission circuit is comprised of all load carrying elements between circuit breakers or the comparable switching devices. A load carrying element within a Base Plan Upgrade that is connected at two different voltage levels (e.g. a 345kV/138kV transformer) shall, for the purposes of this Attachment J, be considered to have a nominal operating voltage of its lower voltage level (excluding any tertiary windings) and its costs shall be allocated in accordance with the rules governing the lower voltage level in this Attachment J. A waiver may be requested to use a transformer's higher voltage level instead of the lower voltage level for the purposes of cost allocation under this Attachment J based on the anticipated utilization of the transformer. Such request must be made in writing with supporting analysis and submitted to the Transmission Provider not later than one hundred eighty (180) days following the inclusion of the transformer in an approved SPP Transmission Expansion Plan. Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to: (i) whether the power flows through the transformer predominately are from the lower voltage to the higher voltage; (ii) whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected. The Transmission Provider shall make a recommendation to accept or deny the waiver, on a non-discriminatory basis, to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee will consider the waiver request and the Transmission Provider's recommendation, and will provide its own recommendation (along with the Transmission Provider's recommendation) regarding such waiver to the SPP Board of Directors. Barring unusual circumstances, the recommendation to approve or reject such waiver request will be submitted to the SPP Board of Directors within one hundred twenty (120) days following the receipt of the waiver request.

A. Allocation of Base Plan Upgrade Costs Eligible for Cost Allocation

1. If the cost of a Base Plan Upgrade is less than or equal to \$100,000, the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan

Zonal Annual Transmission Revenue Requirement of the Zone in which the Base Plan Upgrade is located.

2. If a) the Base Plan Upgrade is included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System or is an approved high priority upgrade, and the cost for that upgrade is not allocable under Section III.A.1; or b) the Base Plan Upgrade cost eligible for cost allocation under Section III.B.1 is not associated with a new or changed Designated Resource for a wind generation plant, then:

i. X% of the annual transmission revenue requirement associated with such Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Region-wide Charge, where X shall be set as follows:

a. For all Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010 or whose nominal operating voltage level is less than 300 kV but greater than 100 kV, X shall be 33%.

b. For all other Base Plan Upgrades whose nominal operating voltage level is greater than or equal to 300 kV, X shall be 100%.

c. For all other Base Plan Upgrades whose nominal operating voltage level is less than or equal to 100 kV, X shall be 0%.

ii. (100-X)% of the annual transmission revenue requirement associated with such Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones' share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment S to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10 MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000.

b. For all other Base Plan Upgrades, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated solely to the Base Plan Zonal Annual Transmission Revenue Requirement of the Zone in which the Base Plan Upgrade is located.

3. If the Base Plan Upgrade cost eligible for cost allocation under Section III.B.1 of Attachment J is a) associated with a new or changed Designated Resource that is a wind generation plant and b) the Base Plan Upgrade is located within the same zone as the Transmission Customer's Point of Delivery, then:

i. X% of the annual transmission revenue requirement associated with the portion of the Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge, where X shall be set as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010 or whose nominal operating voltage level is less than 300 kV and greater than 100 kV, X shall be 33%.

b. For all other Base Plan Upgrades whose nominal operating voltage level is greater than or equal to 300 kV, X shall be 100%.

c. For all other Base Plan Upgrades whose nominal operating voltage level is less than or equal to 100 kV, X shall be 0%.

ii. (100-X)% of the annual transmission revenue requirement associated with the portion of the Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones' share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment S to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10 MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000.

b. For all other Base Plan Upgrades, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of the Zone in which the Base Plan Upgrade is located.

4. If the Base Plan Upgrade cost eligible for cost allocation under Section III.B.1 of Attachment J is a) associated with a new or changed Designated Resource that is a wind generation plant and b) the Base Plan Upgrade is located within a zone(s) other than the Transmission Customer's Point of Delivery, then:

i. Y% of the annual transmission revenue requirement associated with the Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge, where Y shall be set as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010 or whose nominal operating voltage level is less than 300 kV, Y shall be 67%.

b. For all other Base Plan Upgrades Y shall be 100%.

ii. (100-Y)% of the annual transmission revenue requirement associated with the Base Plan Upgrade costs eligible for cost allocation shall be directly assigned to the Transmission Customer.

B. Conditions for Classifying Service Upgrade Costs Associated with Designated Resources As Base Plan Upgrade Costs Eligible for Cost Allocation

1. Except as provided in Section III.A.1 and subject to the limits and rules set forth in Subsections d and f below, the costs of Service Upgrades associated with new or changed Designated Resources shall be classified as Base Plan Upgrade costs eligible for cost allocation if the conditions in the following Subsections a and b are met, and if the condition in Subsection c is met as applicable.

a. The Transmission Customer's commitment to the Designated Resource has a duration of at least five years

b. In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer's existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer's projected system peak responsibility determined pursuant to SPP Criteria 2.

c. If the Designated Resource is a wind generation plant, then the sum of: (1) the requested capacity and (2) the transmission capacity reserved for the Transmission Customer's existing Designated Resources that are wind generation plants shall not exceed 20% of the Transmission Customer's projected system peak responsibility as determined pursuant to SPP Criteria 2 in the first year the

Designated Resource is planned to be used by the Transmission Customer.

d. Safe Harbor Cost Limit for Eligibility of the Costs of Base Plan Upgrade for Cost Allocation

   i. For Base Plan Upgrades that cost over $100,000, the aggregate cost of such upgrades assigned to each individual transmission service request that is less than or equal to the Safe Harbor Cost Limit of $180,000 / MW times the requested capacity is eligible for cost allocation in accordance with:

      1) Section III.A.2 for a new or changed Designated Resource other than a wind generation plant; or

      2) Sections III.A.3 and 4 for a new or changed Designated Resource that is a wind generation plant.

   ii. Any costs that exceed the Safe Harbor Cost Limit for a transmission service request shall be directly assigned to the Transmission Customer unless a waiver of the Safe Harbor Cost Limit is granted pursuant to Section III.C.

e. Base Plan Upgrade costs eligible for allocation as a result of the granting of a waiver shall be allocated in accordance with Sections III.A.2, III.A.3, or III.A.4, as applicable.

f. For each Transmission Service Request, the amount of Base Plan Upgrade costs eligible for cost allocation shall be pro-rated among all Base Plan Upgrades required to grant the Transmission Service Request based upon each Upgrade's cost that is allocated to the Transmission Service Request in accordance with Attachment Z1.

2. The Transmission Customer must provide the Transmission Provider the information that the Transmission Provider deems necessary to verify that the new or changed Designated Resource meets conditions in Section III.B.1.a,b and c above.
3. If an upgrade for a new or changed Designated Resource meets the requirements set forth in Section III.B.1.a, b, and c above, the costs up to the $180,000/MW Safe Harbor Cost Limit will be classified as Base Plan Upgrade costs eligible for cost allocation.
4. If the conditions set forth in Section III.B.1.a, b, and c above are not met, and the Transmission Customer does not secure a waiver of the relevant condition(s), the costs of the upgrades will be directly assigned to the Transmission Customer. If the costs of upgrades associated with a new or changed Designated Resource exceeds the Safe Harbor Cost Limit and the Transmission Customer does not secure a waiver of that limit, the costs of the upgrades in excess of the limit will be directly assigned to the Transmission Customer. The Transmission Customer shall receive transmission revenue credits in accordance with Attachment Z2 to this Tariff for any such directly assigned costs.

C. Waiver of Conditions for Classifying Service Upgrade Costs Associated with Designated Resources As Base Plan Upgrade Costs Eligible for Cost Allocation

1. Waiver Process

If one or more of the conditions in Section III.B.1.a, b, c are not met or if the Base Plan Upgrade cost exceeds the Safe Harbor Cost Limit, the Transmission Customer may seek a waiver from the Transmission Provider in order that the costs of any Service Upgrade(s) that otherwise would be directly assigned to the Transmission Customer may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation.

To obtain a waiver for the conditions set forth in Section III.B.1.a, b, c, the Transmission Customer must submit a request for a waiver to the Transmission Provider simultaneous with its request for long-term transmission service, submitted in accordance with Attachment Z1 to this Tariff, for the new or changed Designated Resource.

Aggregate Facilities Studies performed by the Transmission Provider as part of the Aggregate Transmission Service Study procedure, which is described in Attachment Z1, will determine whether the costs for Service Upgrades associated with a new or changed Designated Resource might exceed the Safe Harbor Cost Limit. If the Transmission Provider determines that the costs for Service Upgrades associated with a new or changed Designated Resource might exceed the Safe Harbor Cost Limit, the Transmission Provider shall notify the affected Transmission Customer when the Transmission Provider posts the associated Facilities Study. The affected Transmission Customer may request a waiver regarding the costs in excess of the Safe Harbor Cost Limit within 15 days of such notice form the Transmission Provider.

Following the receipt of a request for a waiver, the Transmission Provider will review the request and make a determination on a non-discriminatory basis of whether a waiver should be granted based upon consideration of the factors described in Section III.C.2. of this Attachment. The Transmission Customer requesting the waiver shall be responsible for the reasonable costs of any studies that the Transmission Provider performs in making its determination. The Transmission Provider will provide a report and recommendation to the Markets and Operations Policy Committee for each requested waiver. The Markets and Operations Policy Committee will consider the waiver request and the Transmission Provider's report and recommendation, and will provide its own recommendation (along with the Transmission Provider's report and recommendation) regarding each requested waiver to the SPP Board of Directors. Barring unusual circumstances, a valid waiver request will be reviewed and submitted to the SPP Board of Directors within 120 days following the receipt of the waiver request.

2. Factors to be Considered in Evaluating Waiver Requests

Any waiver request submitted by a Transmission Customer pursuant to Section III.C.1. of this Attachment shall be evaluated based upon the following general factors, including but not limited to:

i. There are insufficient competitive resource alternatives for one or more Transmission Customers.

ii. In the event that the aggregate costs of a Service Upgrade associated with a new or changed Designated Resource exceed the Safe Harbor Cost Limit, (i) those costs up to the level of the Safe Harbor Cost Limit shall be classified as Base Plan Upgrade costs eligible for cost allocation, and (ii) those costs that exceed the Safe Harbor Cost Limit may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation taking into account the extent to which the duration of the Transmission Customer's commitment to the new or changed Designated Resource exceeds the five-year commitment period set forth in paragraph III.B.1. above.

iii. The five-year commitment period for the new or changed Designated Resource may be waived if: (i) the associated Service Upgrade costs are significantly less than the Safe Harbor Cost Limit; or (ii) the associated Service Upgrades provide benefits to other Transmission Customers that would offset in less than five years any costs allocated to them as a result of the upgrade being classified as a Base Plan Upgrade.

iv. If a request for a waiver is received by the Transmission Provider based upon other circumstances, such waiver request shall also be considered pursuant to the waiver process described in Section III.C.1. of this Attachment.

If the costs of the Service Upgrade(s) required for a new or changed Designated Resource are not eligible for classification as Base Plan Upgrade costs, the Transmission Customer may nevertheless request the construction of such upgrades. In such event, the costs of such upgrades shall be allocated in accordance with Attachment Z1 to this Tariff.

D. Review of Base Plan Allocation Methodology

1. The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years in accordance with this Section III.D. The Transmission Provider and/or the Regional State Committee may initiate such review at any time. Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.

2. For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts utilizing the analysis specified in Section III.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J.

3. The Transmission Provider shall review the results of the cost allocation analysis with SPP's Regional Tariff Working Group, Markets and Operations Policy Committee, and the Regional State Committee. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.

4. The Transmission Provider shall request the Regional State Committee provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.

   i) One year prior to each three-year planning cycle (starting in 2013) the Markets and Operations Policy Committee and Regional State Committee will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the Regional State Committee and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint; and

   ii) Starting in 2015 and at any time thereafter, any member company that feels that it has an imbalanced cost allocation may request relief through the Markets and Operations Policy Committee. The Markets and Operations Policy Committee recommendation, if any, will be forwarded with the request for relief to the Regional State Committee and Board of Directors for review.

5. In accordance with the SPP Bylaws, the SPP Board of Directors will initiate the appropriate actions, including any necessary filings with the Commission, consistent with the Regional State Committee recommendations.

Effective Date: 7/26/2010 - Docket #: ER10-2244

IV. Approved Balanced Portfolios

One hundred percent (100%) of the annual transmission revenue requirement for an approved Balanced Portfolio shall be recovered through the Region-wide Charge.

A. Reallocation of Zonal Revenue Requirements for Deficient Zone(s)

For an approved Balanced Portfolio, the balance may have been achieved by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual Transmission Revenue Requirement ("Reallocated Revenue Requirements") from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement in accordance with Section IV.4.c of Attachment O to this Tariff.

1. Implementation of Reallocated Revenue Requirements

The initial reallocation of the Reallocated Revenue Requirements from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement shall occur when at least 10% of the estimated levelized annual transmission revenue requirements for the approved Balanced Portfolio has been included in rates under the Tariff (the "Trigger Date").

On the Trigger Date and on the anniversary of the Trigger Date in each of the subsequent four years, 20% of the Reallocated Revenue Requirements required to balance the portfolio for the deficient Zone(s), as estimated in accordance with Section IV.4.c of Attachment O to this Tariff, shall be reallocated to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement. However, if all the upgrades in the approved Balanced Portfolio are completed and included in rates under the Tariff and the actual costs of any third party impacts identified under Section IV.3.c of Attachment O are determined prior to the fourth anniversary of the Trigger Date, the remaining Reallocated

Revenue Requirements shall be reallocated and the true-up specified in Section IV.A.2 of this Attachment shall be performed.

The reallocation of the Reallocated Revenue Requirements shall be from the Base Plan Zonal Annual Transmission Revenue Requirement of the deficient Zone(s) first, then, if necessary, from the Zonal Annual Transmission Revenue Requirement of the deficient Zone(s).

2. Final Reallocation of Reallocated Revenue Requirements and True-up

Upon the completion and inclusion in rates under the Tariff of all of the upgrades that are part of the approved Balanced Portfolio and the determination of the actual cost of any third party impacts attributable to the Balanced Portfolio under Section IV.3.c of Attachment O, the final amount of costs to be reallocated from the Reallocated Revenue Requirements for the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement to balance the approved Balanced Portfolio shall be trued-up based on the applicable fixed charge rate and actual costs. The final reallocation shall be performed using the same benefits estimated at the time the Balanced Portfolio was approved. Notwithstanding the foregoing, if the ten-year net present value of levelized annual transmission revenue requirements based on actual costs and third party impact costs under Section IV.3.c of Attachment O exceeds the ten-year net present value of estimated benefits for the entire approved Balanced Portfolio, then the reallocation for each Zone shall be set at a level that equates the benefit to cost ratio in each Zone to the trued-up benefit to cost ratio for the approved Balanced Portfolio.

B. Reconfiguration of an Approved Balanced Portfolio

1. Conditions Under Which an Approved Balanced Portfolio may be Reconfigured

Under certain conditions, the Transmission Provider shall review an approved Balanced Portfolio for unintended consequences and may recommend reconfiguring a previously approved Balanced Portfolio. Conditions that would initiate such review include but are not limited to:

i. Cancellation of an upgrade that is part of an approved Balanced Portfolio;

ii. Unanticipated decreases in benefits or increases in the costs of upgrades that are part of an approved Balanced Portfolio or increases in the costs of third party impacts under Section IV.3.c of Attachment O; and

iii. Significant unanticipated changes in the transmission system.

2. Factors to be Considered in Determining Whether a Balanced Portfolio Should be Reconfigured

Reconfiguration of a Balanced Portfolio shall be evaluated based upon the following general factors, including but not limited to, the impact of the reconfiguration on:

i. Meeting the conditions for a Balanced Portfolio specified in Section IV.3.e of Attachment O to this Tariff;

ii. The number of deficient Zones as defined in Section IV.4.a of Attachment O to this Tariff;

iii. The amount of Reallocated Revenue Requirements that needs to be transferred from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement in order to balance the reconfigured portfolio; and

iv. The increase in the overall cost of the reconfigured Balanced Portfolio, if upgrades are added to the portfolio.

3. Reallocation of Reallocated Revenue Requirements

If a reconfigured portfolio is to be balanced by transferring a portion of the Reallocated Revenue Requirements from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement, the reallocation of the revenue requirements specified in Section IV.A of this Attachment shall be adjusted based on the costs and benefits of the proposed reconfigured Balanced Portfolio as approved.

4. Recommendation and Approval of a Reconfigured Balanced Portfolio

Based on the analysis performed in accordance with Sections IV.B.1 through IV.B.3 of this Attachment, the Transmission Provider shall provide a report and make a recommendation in regard to reconfiguration of the Balanced Portfolio to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee shall consider the Transmission Provider's report and recommendation, and shall provide its own recommendation (along with the Transmission Provider's report and recommendation) to the SPP Board of Directors. Based upon these recommendations, the SPP Board of Directors shall take action regarding reconfiguration of the Balanced Portfolio.

Effective Date: 7/26/2010 - Docket #: ER10-1960

V. Other Network Upgrades

A. Sponsored Upgrades

The Directly Assigned Upgrade Cost of a Sponsored Upgrade shall be borne voluntarily by the Project Sponsor. The Project Sponsor shall execute an Agreement for Sponsored Upgrade in which it agrees to bear these Directly Assigned Upgrade Costs. In the Agreement, the Project Sponsor shall elect to pay for the Sponsored Upgrade by (1) a lump sum payment or (2) periodic charges calculated in accordance with Commission policy (both hereafter referred to as "Project Sponsor's Payment"). Such periodic charges shall be paid on a monthly basis over a twenty year period unless a different frequency and/or shorter term is established in the Agreement for Sponsored Upgrade. The present value of the Project Sponsor's Payment shall equal the present value of the annual revenue requirements of the Sponsored Upgrade over a twenty year plant life. The annual revenue requirements of the Sponsored Upgrade shall be calculated by multiplying the levelized fixed charge rate of the Transmission Owner, based on full depreciation over a 20 year plant life and including operating and maintenance expenses and any applicable tax consequences, by the nondepreciated actual cost of the Sponsored Upgrade.

The Transmission Provider shall file the Agreement initially utilizing good faith estimates of the construction costs for the assigned upgrade. Upon completion of the Sponsored Upgrade, the Transmission Provider shall true up the Directly Assigned Upgrade Costs to the actual construction costs as appropriate and calculate the Project Sponsor's Payment.

In addition, the Directly Assigned Upgrade Cost of the Sponsored Upgrade shall be reduced as provided in Section VII of this Attachment J and by any revenue credits granted to a Transmission Owner for the use of the Sponsored Upgrade.

The Project Sponsor shall receive transmission revenue credits in accordance with Attachment Z2.

B. Service Upgrades

The cost of a Service Upgrade shall be allocated in accordance with Attachment Z1 to this Tariff. The Transmission Customer shall receive transmission revenue credits in accordance with Attachment Z2.

C. Generation Interconnection Related Network Upgrades

The cost of a generation interconnection related Network Upgrade shall be allocated in accordance with Attachment V to this Tariff. The Interconnection Customer shall receive transmission revenue credits in accordance with Attachment Z2.

D. Zonal Reliability Upgrades

1. The cost of Zonal Reliability Upgrades (i) included in the 2005 SPP Transmission Expansion Plan and (ii) placed in service prior to January 1, 2008 shall be allocated in accordance with Section III to this Attachment.
2. The cost of all other Zonal Reliability Upgrades shall be includable in the applicable Zonal Annual Transmission Revenue Requirement.

Effective Date: 7/26/2010 - Docket #: ER10-1960

VI. Reserved

Effective Date: 7/26/2010 - Docket #: ER10-1960

VII. Treatment of Upgrades that Permit Deferral or Displacement of Network Upgrades

A. Deferred Upgrade

In the case of a Base Plan Upgrade, an upgrade that is part of an approved Balanced Portfolio, a Zonal Reliability Upgrade, or a Service Upgrade that may be deferred ("Deferred Upgrade") as a result of a proposed Network Upgrade, the achievable Accredited Revenue Requirements shall be equal to the time value of the affected Transmission Owner's(s') revenue requirement(s) for the Deferred Upgrade over the period of the deferral, calculated as follows:

1. A Transmission Owner's annual revenue requirement for a Deferred Upgrade shall be determined using the same method as is used by the Transmission Owner to calculate its revenue requirement for transmission facilities for other purposes, but applying that method to the projected incremental investment in the Deferred Upgrade.
2. The time value of the deferral shall be calculated by discounting to present value the accredited annual revenue requirements for each individual year in the deferral period and summing the resulting values. For each individual year in the deferral period, the time value of the deferral will be determined by discounting the annual revenue requirement for that year first from January 1 of that year and then from December 31 of that year, summing the two resulting values, and dividing by two. For any partial year encompassed by the deferral period, the time value of the deferral shall be calculated in the same manner as indicated in the immediately preceding sentence, except that the resulting value will be pro-rated based on the number of months in the partial year divided by 12.

B. Displaced Upgrade

In the case of a Base Plan Upgrade, an upgrade that is part of an approved Balanced Portfolio, a Zonal Reliability Upgrade, or a Service Upgrade that may be displaced ("Displaced Upgrade") as a result of a proposed Network Upgrade, the achievable Accredited Revenue Requirements shall be equal to the time value of the affected Transmission Owner's(s') revenue requirement(s) for the Displaced Upgrade over the expected service life of the facility that is displaced. The methodology for calculating the Accredited Revenue Requirements shall be the same as set forth in Section VII.A. of this Attachment, except that the expected service life of the facility shall be substituted for the deferral period in all instances.

C. Application of Accredited Revenue Requirements

The Transmission Provider shall calculate the Accredited Revenue Requirements that are achievable due to a Deferred Upgrade or Displaced Upgrade. The Accredited Revenue Requirements shall be based on the estimated project costs for the approved upgrade which is deferred or displaced.

1. If a proposed Network Upgrade defers or displaces the need for a Base Plan Upgrade associated with a new or changed Designated Resources for which there are Directly Assigned Upgrade Costs, the Accredited Revenue Requirements related to Base Plan Upgrade charges shall only include the costs that are allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and the Base Plan Region-wide Annual Transmission Revenue Requirement.
2. If a proposed Network Upgrade defers or displaces the need for an upgrade that is part of an approved Balanced Portfolio, the Accredited Revenue Requirements related to Balanced Portfolio charges shall only include the costs that are allocated to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.
3. If a proposed Network Upgrade defers or displaces the need for a Zonal Reliability Upgrade, the Accredited Revenue Requirements related to Zonal Reliability Upgrade charges shall only include the

costs that are assigned to the Zonal Annual Transmission Revenue Requirement.

4. If a proposed Network Upgrade defers or displaces the need for a Service Upgrade required to provide Long-Term Firm Point-to-Point Transmission Service, the Accredited Revenue Requirements related to the transmission service charges shall only include the expected increase in revenue that can be distributed through Section II.C of Attachment L to this Tariff, for service under Schedule 7, as a result of displacement or deferral of the Service Upgrade.

D. Assignment and Recovery of Accredited Revenue Requirements

1. For a proposed Network Upgrade, other than an upgrade included in a Balanced Portfolio, that results in a Deferred Upgrade or Displaced Upgrade:

   i. The entity responsible for paying the cost of the Network Upgrade shall be responsible for any positive difference between the present value of the total costs for its upgrade and the present value of the Accredited Revenue Requirements.

   ii. The Accredited Revenue Requirements of the deferred or displaced upgrades shall be recovered through charges specified in:

      a. Section III.A of this Attachment for deferred or displaced Base Plan Upgrades;

      b. Section IV of this Attachment for deferred or displaced upgrades associated with a Balanced Portfolio;

      c. Section V.D of this Attachment for deferred or displaced Zonal Reliability Upgrades; and

      d. Section V.B. of this Attachment for deferred or displaced Service Upgrades.

   iii. The calculations for determining the Accredited Revenue Requirements shall be filed with the Commission by the

Transmission Provider prior to the imposition of any charges or credits hereunder.

2. The costs of the upgrades included in an approved Balanced Portfolio that result in a Deferred Upgrade or Displaced Upgrade shall be included in the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement and shall be recovered through the Region-wide Charge.

   i. The costs of a Network Upgrade that is deferred or displaced by the upgrades included in an approved Balanced Portfolio shall not be recovered through the original recovery mechanism for such upgrade.

   ii. In the evaluation of the benefits of the Balanced Portfolio as specified in Section IV.3.d of Attachment O to this Tariff, the Accredited Revenue Requirements associated with the deferred or displaced Base Plan Upgrade(s), Zonal Reliability Upgrade(s) and Service Upgrade(s) shall be treated as benefits to the Zones to which those Accredited Revenue Requirements are distributed or would have been otherwise assigned or recovered as specified in:

      a. Section III.A of this Attachment for deferred or displaced Base Plan Upgrades;

      b. Section V.D of this Attachment for deferred or displaced Zonal Reliability Upgrades; and

      c. Section II.C of Attachment L for service under Schedule 7 for deferred or displaced Service Upgrades.

VIII. Uncompleted Network Upgrades

The costs of Network Upgrades that are not completed through no fault of the Transmission Owner charged with construction of the upgrades shall be handled as follows:

If a proposed Network Upgrade was accepted and approved by the Transmission Provider, the Transmission Provider shall develop a mechanism to recover such costs and distribute such revenue on a case by case basis. Such recovery and distribution mechanism shall be filed with the Commission. The Transmission Owner(s) that incurred the costs shall be reimbursed for those costs by the Transmission Provider. These costs shall include, but are not limited to: the costs associated with attempting to obtain all necessary approvals for the project, study costs, and any construction costs.

Effective Date: 7/26/2010 - Docket #: ER10-1960

Schedule 1 to Attachment J

Agreement For Sponsored Upgrade

This Agreement For Sponsored Upgrade ("Agreement") is entered into this _______ day of ____________________, ________, by and between ______________________________ ("Project Sponsor"), and Southwest Power Pool, Inc. ("Transmission Provider") on behalf of itself and the designated Transmission Owner(s). The Project Sponsor and Transmission Provider shall be referred to as "Parties."

WHEREAS, the Transmission Provider administers an Open Access Transmission Tariff ("Tariff") to provide Transmission Service within the Southwest Power Pool and acts as agent for the Transmission Owners in providing service under the Tariff; and

WHEREAS, the Sponsored Upgrade identified in the Specifications attached hereto has been endorsed by the Markets and Operations Policy Committee and the Board of Directors of the Transmission Provider; and

WHEREAS, the Project Sponsor has agreed to bear the cost of the Sponsored Upgrade; and

WHEREAS, the Parties intend that capitalized terms used herein shall have the same meaning as in the Tariff;

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein, the Parties agree as follows:

1.0 This Agreement shall become effective on the later of (l) the date of the execution of this Agreement by both Parties or (2) such other date as it is permitted to become effective by the Commission. ("Effective Date")

2.0 This Agreement shall terminate on the later of the following events: (1) the Project Sponsor has fulfilled its obligation to make Project Sponsor's Payment pursuant to section 3.0 or (2) the Transmission Provider has fulfilled its obligation to pay the Project Sponsor all revenue credits pursuant to section 5.0, recognizing that no obligation to pay revenue credits will remain after the Sponsored Upgrade has been permanently removed from service.

3.0 Project Sponsor agrees to pay the Directly Assigned Upgrade Costs of the Sponsored Upgrade pursuant to Attachment J of the Tariff. Project Sponsor has elected to pay for the Sponsored Upgrade in one of the following manners, as indicated in the Specifications attached hereto: (1) by a lump sum payment or (2) a periodic charge, both hereinafter referred to as "Project Sponsor's Payment." The Parties recognize that the initial Project Sponsor's Payment will be based on an estimate of the Directly Assigned Upgrade Costs. While Transmission Provider represents that the Project Sponsor's Payment is based on a good faith estimate of the Directly Assigned Upgrade Costs, such estimate shall not be binding, and the Project Sponsor shall compensate the Transmission Provider and designated Transmission Owner(s) for all costs incurred pursuant to the provisions of the Tariff. Promptly after the

Sponsored Upgrade is placed in service, Transmission Provider shall adjust the Project Sponsor's Payment to reflect all such costs incurred, as appropriate.

4.0 Project Sponsor shall maintain a Letter of Credit in the amount specified in this Agreement or such other form of security acceptable to Transmission Provider pursuant to Attachment X of the Tariff until such time as the Project Sponsor has fulfilled its obligation to make Project Sponsor's Payment pursuant to section 3.0.

5.0 Transmission Provider agrees to provide Project Sponsor with revenue credits pursuant to Attachment Z2 of the Tariff. Revenue credits shall be the exclusive compensation of the Project Sponsor under this Agreement.

6.0 Transmission Provider agrees to arrange for the construction of the Sponsored Upgrade in accordance with the Tariff, the SPP Membership Agreement and the construction timeline specified herein.

7.0 Any notice or request made to or by either Party regarding this Agreement shall be made to the representative of the other Party as indicated below.

Southwest Power Pool, Inc.:

____

201 Worthen Drive

Little Rock, AR 72223-4936

Project Sponsor:

____

____

____

8.0 The Tariff is incorporated herein and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

Southwest Power Pool, Inc.:

By:______________________ ______________________ ______________________
Name Title Date

Project Sponsor:

By:______________________ ______________________ ______________________
Name Title Date

Specifications

1.0 Designated Transmission Owner(s): ______________________________

2.0 Description of Sponsored Upgrade: ______________________________

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3.0 Project Sponsor's Payment:* The Project Sponsor shall elect to pay the Directly Assigned Upgrade Grade Costs of the Sponsored Upgrade by (1) a lump sum payment or (2) a periodic charge as indicated below:

_____ Lump Sum Payment:______________________________

Payment Due Date:______________________________

_____Periodic Charge:______________________________

____

____

* The Project Sponsor's Payment specified herein shall initially be based on a good faith estimate of Directly Assigned Upgrade Costs. The Project Sponsor's Payment shall be subject to adjustment and true up after the Sponsored Upgrade is placed in service.

4.0 Project Timeline (Milestones): ______________________________

____

____

5.0 Letter of Credit: