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

RUTH M. SAKYA

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

February 4, 2013

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
BPS	Bulk Power System
CCN	Certificate of Public Convenience and Necessity
Commission	New Mexico Public Regulation Commission
CP	Coincident Peak
EI	Energy Imbalance
EIS	Energy Imbalance Service
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause
HE	Hour Ending
LIP	Locational Imbalance Price
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
PUA	Public Utility Act
PUCT	Public Utility Commission of Texas
RNU	Revenue Neutrality Uplift

Acronym/Defined Term	**Meaning**
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
RE	Regional Entity
SPS	Southwestern Public Service Company, a New Mexico Corporation
Stipulation	Uncontested Stipulation from Case No. 07-00390-UT
UD	Uninstructed Deviation
WECC	Western Electric Coordinating Council
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

LIST OF ATTACHMENTS

Case No. 13-00___-UT
Direct Testimony
of
Ruth M. Sakya

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ruth M. Sakya. My business address is 1400 Ducale Drive SE, Rio Rancho, New Mexico 87124.

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

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") 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 Manager, Regulatory Policy.

Q. Please briefly outline your responsibilities as Manager, Regulatory Policy.

A. I am responsible for determining the appropriate regulatory policy for SPS. In this role, I direct and prepare comments, testimony, and briefing materials for policy matters impacting SPS. Among my responsibilities are involvement with SPS's Southwest Power Pool ("SPP") and related reliability matters before the

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[1] Xcel Energy is the parent company of the following four wholly owned 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; and SPS. Xcel Energy's natural gas pipeline subsidiary is WestGas InterState, Inc.

New Mexico Public Regulation Commission ("Commission") and the Public Utility Commission of Texas ("PUCT"). In carrying out my responsibilities regarding these matters, I have become familiar with the Commission's rules affecting these areas, the Public Utility Act ("PUA"),[2] and related federal rules and statutes.

Q. Please describe your educational background.

A. I graduated from the University of Wyoming in 1998 with a Bachelor of Science degree in Finance and, in 2001, with a Master of Science degree in Finance, with an emphasis in Regulatory Economics. I have completed the coursework and successfully passed the qualifying exams for a Ph.D. in Public Affairs from the University of Colorado, Denver.

[2] NMSA 1978, Sections 62-3-1, *et seq.*

Q. Please describe your professional experience.

A. I began my career in 1999 as an intern with the Illinois Commerce Commission and in 2000 joined the PUCT as a Senior Policy Analyst. I have held various other positions, including Rate Analyst at a multijurisdictional electric and gas utility, and Senior Analyst and Supervising Analyst with a consulting firm specializing in services to regulatory agencies and municipal entities. In 2004, I accepted a position with Xcel Energy Services Inc. ("XES") as Senior Rate Analyst. In 2007, I accepted a position with XES as Manager, Regulatory Policy. Beginning January 1, 2012, my position as Manager, Regulatory Policy was transferred to SPS where my job responsibilities continue to be the same as they have been since 2007.

Q. Have you testified before any regulatory authorities?

A. Yes. I have testified before the Commission, PUCT, and Colorado Public Utilities Commission on a variety of issues, among them SPP regulatory accounting issues, ratemaking issues, and utility commission's authority over SPS's operations.

II. ASSIGNMENT AND SUMMARY OF RECOMMENDATIONS

Q. What is your assignment in this proceeding?

A. As part of the Uncontested Stipulation in Case No. 07-00390-UT ("Stipulation"), SPS is required to file an Interim Report.[3] As part of that Interim Report, SPS is required to provide details about various costs associated with its continued participation in the SPP. Consistent with this requirement, I will address 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.

Additionally, I address the North American Electric Reliability Corporation ("NERC") fees SPS pays to the SPP Regional Entity ("RE"); 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 certain reporting and notification requirements under the Stipulation.

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

A. Consistent with the Commission-approved Stipulation, SPS presents the costs and revenues associated with its participation in the SPP, and the costs associated with the SPP's function as RE. My discussion of these costs and benefits, in conjunction with SPS witness Mr. Grant's testimony, demonstrates that SPS's

[3] SPS witness William A. Grant provides a copy of the Stipulation as his Attachment WAG-1.

New Mexico retail customers have benefited, and will continue to benefit, from SPS's participation in the SPP.

In addition, I demonstrate that SPS's participation in the SPP will not diminish the Commission's ratemaking and regulating authority over SPS, thus confirming the Commission's continued ability to protect New Mexico retail customers.

III. <u>SPP-RELATED CHARGES AND REVENUES</u>

Q. What topics do you cover in this section of your testimony?

A. In this section, I identify SPS's charges and revenues from the SPP associated with wheeling; quantify these charges and revenues for 2013 and 2014 (the final two years of the Interim Report period); and discuss the ratemaking treatment of these charges and revenues.

Q. Please briefly discuss the wheeling activities that are the basis for the expenses and revenues discussed in this section.

A. The wheeling expenses and revenues I discuss are associated with SPS's participation in the SPP. SPS witness William A. Grant discusses SPS's participation in the SPP in detail in his testimony. SPS is a member of the SPP regional transmission organization ("RTO") and provides transmission service as part of the SPP. The Federal Energy Regulatory Commission ("FERC") oversees RTOs and approves their Open Access Transmission Tariffs ("OATT"). Thus, SPS provides transmission service under FERC-approved tariffs.

Q. What is "wheeling"?

A. Wheeling refers to the transfer of electric power by use of the transmission network of one utility for the benefit of a transmission customer, such as another utility or independent power generator. Wheeling is also commonly referred to as transmission service and is provided under a FERC-approved OATT. OATTs set out the terms and conditions of service and charges to customers, for transmission services. The two most common types of transmission service are point-to-point and network service.

Q. Please describe point-to-point transmission service.

A. Point-to-point transmission service occurs when a transmission system owner transports electric power for a transmission customer between a specific point of entry into the transmission owner's system and a specific point of exit. For example, if a seller delivers power to a transmission owner at a specific transmission interconnection point (*e.g.*, the Oklahoma interconnection) and asks the transmission owner to deliver that power to a buyer at another specific transmission interconnection point (*e.g.*, the New Mexico interconnection) then the transmission owner has provided point-to-point transmission service from the Oklahoma interconnection to the New Mexico interconnection.

Q. What is network transmission service?

A. Network transmission service occurs when a transmission customer has use of a utility's entire transmission system, and not just specific points of entry and exit. For example, in a situation where a rural electric cooperative is connected with a utility at five interconnection points and purchases its power from three generators from all or any of those points. If this cooperative uses network service, the utility uses its transmission system to deliver the power produced by any of the three generators to the five interconnection points. Network transmission service is normally either paid for on a load ratio share basis or monthly coincident peak basis. This means that both the host utility and the transmission customers pay for the total transmission system based upon their percentage of the total system load or their contribution to the monthly coincident peak.

Q. Does another SPS witness describe the SPP OATT?

A. Yes. SPS witness Mr. Grant's discusses the SPP OATT.

Q. Where are SPS's transmission wheeling expenses recorded?

A. The majority of SPS's transmission wheeling expenses are recorded in FERC Account 565, which includes amounts payable to others for the transmission of electricity purchased by SPS. The SPP administrative fees are recorded in FERC Accounts 561.4, 561.8, and 575.7. These expenses are handled through SPS's base rates.

In addition, the energy-related charges and revenues are recorded in FERC Account 555 and the New Mexico retail share of the net balance is recovered or returned through SPS's fuel in base and fuel and purchased power adjustment clause ("FPPCAC"). I will first discuss the base rate components (expenses and revenues) and then address the energy-related charges and revenues.

A. Transmission Service Charges – Base Rate Recovery

Q. Please describe the transmission expenses recorded in FERC Account 565 that SPS incurs under the SPP OATT.

A. SPS incurs several types of transmission-expenses under the SPP OATT, which are recorded in FERC Account 565. I categorize these wheeling expenses as follows:

- *Wholesale Sales*, which contain wheeling expenses related to power sales by SPS to other wholesale entities, which may be other investor-owned utilities, municipal utilities, or electric cooperatives. For example, if SPS purchases network transmission service from the SPP for SPS's wholesale power sale to Farmers' Electric Cooperative, Inc., SPS's retail customers should not pay these costs. Accordingly, SPS allocates 100% of the wheeling costs associated with wholesale sales to the wholesale jurisdiction.
- *Retail*, which contain all of the costs the SPP charges to SPS under the SPP OATT for Retail FERC Assessments (Schedule 12) and transmission infrastructure costs. The FERC Assessments are delineated between retail and wholesale charges, with the retail portion allocated between SPS's two retail jurisdictions. The wholesale charges are included in the *Wholesale Sales* category. The transmission infrastructure costs are needed for transmission reliability. Similar to the wholesale assessments, transmission infrastructure assessments are included in the *Wholesale Sales* category. SPS allocates these costs between its two retail jurisdictions using a transmission allocator.
- *Purchases*, which contain wheeling expenses related to wholesale power purchases made by SPS for the benefit of all of its customers. For example, in the past, SPS purchased power from an Exelon Generation Company, LLC generator in Oklahoma, and paid the SPP for point-to-point transmission service to wheel the power into the SPS control area. Given that transmission costs in this category benefit all of SPS's customers, SPS allocates these costs to all of its jurisdictions using a production allocator.

- *Transmission*, which contains charges for reserve sharing events, is needed for transmission reliability. The transmission costs benefit all of SPS's customers and, thus, SPS allocates the costs to all of its jurisdictions using a transmission allocator.

Q. Please describe the retail FERC assessment costs recorded in FERC Account 565.

A. FERC is a self funded regulatory agency and requires RTOs to assess charges to their customers. As I mentioned earlier, SPS segregates the FERC Assessments between retail and wholesale charges, with the retail portion allocated between SPS's two retail jurisdictions (New Mexico and Texas). The wholesale charges are included in the *Wholesale Sales* category.

Q. Please describe the SPP transmission infrastructure costs recorded in FERC Account 565.

A. Transmission infrastructure costs are incurred by SPS as a result of the SPP's transmission expansion plan. In addition, the transmission infrastructure costs include the balanced portfolio transfer payments, which began in October, 2012. Mr. Grant discusses these costs in more detail in his testimony.

Q. How are transmission infrastructure costs accounted for in SPS's base rates?

A. As I mentioned earlier, SPS segregates these costs between retail and wholesale. The retail component of the transmission infrastructure is allocated between SPS's two retail jurisdictions, while the wholesale component is direct assigned to the FERC jurisdiction. Later in my testimony, I will describe how a revenue credit is applied against the revenue requirement to reflect revenues received from the SPP for the SPP transmission investment projects.

Q. Please briefly describe the charges related to reserve sharing.

A. SPS participates in the SPP's reserve sharing group, allowing SPS to minimize costs by effectively coordinating the use of generation resources at the time of an emergency, thereby minimizing the required level of contingency reserve for each member. Because these costs are related to transmission reliability and benefit all of SPS's customers, SPS allocates the costs to all of its jurisdictions using a transmission allocator.

Q. Are there other wheeling expenses not recorded in FERC Account 565 but recovered through base rates?

A. Yes. In an effort to provide more transparency regarding RTO charges, FERC created three sub-accounts and required RTOs to segregate their charges so that utilities could record RTO fees in these sub-accounts (FERC Order No. 668). The three sub-accounts created by FERC Order No. 668 as described in the Uniform System of Accounts are:

- FERC Account 561.4 – Scheduling, System Control and Dispatching Services

> This account shall include the costs billed to the transmission owner, load serving entity, or generator for scheduling, system control, and dispatching service. Include in this account

> service billings for system control to maintain the reliability of the transmission area in accordance with reliability standards, maintaining defined voltage profiles, and monitoring operations of the transmission facilities.

- FERC Account 561.8 – Reliability Planning and Standards Development Services

> This account shall include the costs billed to the transmission owner, load serving entity, or generator for system planning of the interconnected bulk electric transmission system. Include also the costs billed by the regional transmission service provider for system reliability and resource planning to develop long-term strategies to meet customer demand and energy requirements. This account shall also include fees and expenses for outside services incurred by the regional transmission service provider and billed to the load serving entity, transmission owner, or generator.

- FERC Account 575.7 – Market Administration, Monitoring and Compliance Services

> This account shall include the costs billed to the transmission owner, load serving entity, or generator for market administration, monitoring, and compliance services.

The SPP collects its costs through Administration Fees under Schedule 1-A of the SPP OATT and a Monthly Assessment under the SPP Bylaws. SPS has separated these fees and assessments into similar categories (Retail, Wholesale Sales, Purchases, and Transmission) as the wheeling costs (other than the FERC Assessments) recorded in FERC Account 565, and identified the fees related to SPS's retail service. SPS allocates the retail component of these costs between its retail customers.

Q. Has SPS quantified the base rate costs of SPS's participation in the SPP?

A. Yes. Please refer to Attachment RMS-1, where I have provided SPS's total projected SPP costs for 2013 and 2014.

Q. How were the 2013 and 2014 wheeling expenses derived?

A. The majority of these wheeling expenses come from SPS's October 2012 corporate budget. SPS has also made a limited number of adjustments to the budget to reflect known changes in circumstances since the development of the budget.

Q. Please discuss the budget adjustment.

A. SPS made the following rate case adjustments to the budget: (i) the transmission base plan upgrades were calculated using recent information from the SPP; and (ii) transmission reserve sharing costs were included at historic levels.

Q. With regard to your first adjustment, please explain the adjustment to the Base Plan Upgrade costs.

A. The SPP Base Plan Upgrade charges were adjusted to reflect the 2013 revenue requirements assigned to the SPS zone by the SPP. Attachment RMS-2 presents the calculation. Mr. Grant discusses SPP Base Plan Upgrades and how SPP charges for them under the SPP OATT in more detail.

Q. With regard to your adjustment, what adjustments were made to the transmission reserve sharing expenses?

A. The budget does not include transmission reserve sharing, because SPS is unable to accurately forecast the expenses on a monthly level. However, SPS does incur reserve sharing expenses each year. To determine the 2013 and 2014 levels of expenses, the actual expenses incurred in the 12-months ended June 30, 2012 (the historic base period used in SPS's pending rate case, Case No. 12-00350-UT) were used as a surrogate.

B. <u>Transmission Service Revenues – Base Rates</u>

Q. Do SPS's base rates also reflect revenues from transmission service?

A. Yes. Similar to wheeling costs incurred, SPS receives revenues from its provision of transmission service. These revenues are recorded in the FERC Account 456 series of accounts, specifically FERC Accounts 45605, 45606, 45607, 45609, 45612, 45614, 45616, 45622, 45624, 45626, 45628, 45669, 45671, and 45673.

Q. Please describe the transmission revenues recorded in FERC Account 45605, 45606, and 45607.

A. FERC Accounts 45605, 45606, and 45607 reflects revenues SPS receives for providing transmission service. The network portion of these revenues is eliminated from the cost of service because these revenues relate to revenues received from wholesale network transmission customers and network transmission customer loads are included in the transmission jurisdictional cost allocation (*i.e.*, costs attributable to these customers are allocated to them through the jurisdictional allocators). However, the point-to-point portion of the revenues are credited to each jurisdiction SPS serves (New Mexico retail, Texas retail, and FERC) based upon a 12-coincident peak ("CP") transmission demand allocator to match how investment costs are allocated to each jurisdiction.

Q. What revenues are recorded in FERC Account 45609?

A. FERC Account 45609 contains revenues from the SPP associated with directly assigned transmission projects and from wholesale customers for metering facilities. Currently, SPS's only direct assigned transmission projects under the SPP OATT are the radial transmission lines. SPS directly assigns the costs associated with these radial transmission lines to its wholesale customers, so these facilities are not included in SPS's transmission plant in retail base rate proceedings. Similarly, SPS directly assigns the costs associated with metering wholesale loads to its wholesale customers. The revenues are directly assigned to wholesale.

Q. Please describe the revenues recorded in FERC Accounts 45612, 45671, and 45614.

A. Schedule 1 revenues are recorded in FERC Accounts 45612 and 45671 and Schedule 2 revenues are recorded in FERC Account 45614. Schedule 1 is entitled Scheduling, System Control and Dispatch Service. Schedule 2 is entitled Reactive Supply and Voltage Control from Generation Sources Service. FERC considers both of these services to be necessary services when providing transmission service and, thus, has termed them ancillary transmission services. Each time transmission service is provided to a transmission customer, both Schedule 1 and Schedule 2 services are also provided to that customer. Therefore, transmission revenues and ancillary service revenues tend to go hand in hand.

Q. How are Schedule 1 revenues treated in the cost of service?

A. The network portion of these revenues is treated identical to that of transmission service, and is eliminated from the cost of service because these revenues are related to SPS's wholesale jurisdiction and the network customers that are included in the transmission jurisdictional allocators. The point-to-point portion of the revenues are credited to each jurisdiction SPS serves (New Mexico retail, Texas retail, and FERC) based upon a 12-CP transmission demand allocator that matches how investment costs are allocated to each jurisdiction.

Q. How are Schedule 2 revenues treated in the cost of service?

A. Reactive Power within the power factor deadband (.95 leading to .95 lagging) is considered a requirement for all generators for which there is no specific compensation under Schedule 2. Compensation is provided for Reactive Power specifically provided and needed outside of the deadband. That is, under Schedule 2, SPS receives compensation when it provides reactive power outside of the specified deadband. The Schedule 2 revenues are allocated among the jurisdictions using a production allocator because SPS's generators are used to supply reactive power.

Q. Please describe the revenues recorded in FERC Accounts 45616, 45622, 45624, 45626, and 45628.

A. These FERC Accounts capture costs that are assigned to SPS's wholesale customers. Specifically, FERC Account 45616 includes Schedule 3, Regulation and Frequency Response Service, which is necessary to provide continuous balancing of resources (generation and interchange) with load, and maintenance of scheduled interconnection frequency at sixty cycles per second. Schedule 5 revenues are included within FERC Account 45622. These revenues are related to Spinning Reserve Service, which is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. FERC Account 45624 includes revenues for Schedule 6, which is Supplemental Reserve Service. This service is needed to serve load in the event of a system contingency. FERC Account 45626 includes FERC Assessment revenues received from wholesale customers. Finally, FERC Account 45628 includes generation step-up revenues received from wholesale customers. All of these are revenues associated with wholesale network transmission customers and therefore, SPS has direct assigned them to its wholesale jurisdiction.

Q. What revenues are recorded in FERC Accounts 45669 and 45673?

A. Revenues associated with Base Plan Upgrades are recorded in FERC Accounts 45669 and 45673 and SPS revenue credits these expenses.

Q. What are SPS's projected 2013 and 2014 levels of wheeling revenue?

A. The wheeling revenues are summarized in Attachment RMS-3.

Q. What is the source of the wheeling revenues?

A. The wheeling revenues were, for the most part, derived from SPS's October 2012 corporate budget. SPS made one adjustment to the revenues.

Q. Are all of the revenues credited in the cost of service?

A. No, not all of these revenues are credited against the New Mexico retail revenue requirement. Wholesale network revenues are direct assigned to the FERC jurisdiction, consistent with the treatment of costs. Generally speaking, the point-to-point revenues are allocated between SPS's jurisdictions. Attachment RMS-4 provides a summary of each revenue account and the associated cost of service treatment.

Q. Please describe the adjustment made to determine the 2014 revenues.

A. In Case No. 12-00350-UT, SPS increased the transmission revenues related to SPP Base Plan Upgrades, which synchronizes SPS's requested transmission plant additions and the associated increased SPP charges with the network SPP revenues.

Q. Please describe how SPS calculated the adjustment to the 2014 SPP revenues.

A. SPS began with the forecasted transmission plant data. SPS's Capital Asset Accounting group segregated the forecasted plant closings for Base Plan Upgrade projects. Next, SPS used the 2013 SPS Transmission Formula Attachment O, Worksheet P, which is the Base Plan Upgrade revenue requirement section of the formula. To that formula, SPS added the additional projects that were closing in 2014 using the same carrying charge from the 2013 formula, which is the best estimate for the carrying charge available at this time.

Q. Does SPS receive any other revenues from the SPP?

A. Yes. SPS receives the following revenues from the SPP:

- Revenue associated with transmission service over *distribution facilities*. SPS provides transmission service to several rural electric cooperatives and municipalities in its balancing area, where some of the delivery points are at distribution voltages. These distribution facilities are assigned to the wholesale jurisdiction during base rate proceedings and, accordingly, the revenues are directly assigned to wholesale. These revenues are recorded in FERC Account 456.01.
- Revenues received from SPS's participation in the SPP's *reserve sharing program*. When SPS receives revenue, it means that SPS provided energy to other reserve sharing members within the SPP. These revenues are considered economy and emergency revenues that SPS shares with New Mexico ratepayers through a fuel credit, and, are therefore removed from base rates. These revenues are recorded in FERC Account 447.

C. ***<u>Energy-Related Charges and Revenues Under the SPP OATT</u>***

Q. How are the SPP energy-related charges and revenues settled?

A. SPS's energy-related charges and revenues are settled through the energy imbalance service ("EIS") market on a net basis. Mr. Grant discusses the EIS market in more detail in his testimony.

Specifically, load and resources within the SPP are subject to financial settlement of Imbalance Energy. The SPP EIS market creates a financial settlement for Imbalance Energy (or EIS) based on the difference between the actual generation and load, and what was pre-arranged through advance schedules' times the clearing price or locational imbalance price ("LIP") for the energy.

The SPP market settlement dollar amount associated with the imbalance energy is calculated by taking the megawatt-hour ("MWh") volume of Energy Imbalance ("EI") and multiplying by the LIP at the settlement point on the grid where the imbalance occurred. For example, if the SPS load area experienced a 74 megawatt ("MW") higher actual load compared to the pre-scheduled forecast load for Hour Ending ("HE") 1400 on a particular day, the 74 MW would be multiplied by the LIP for the SPS load settlement point for that hour (*e.g.*, $62.44 per MWh) to determine the load imbalance charge. Similarly, if SPS had pre-scheduled to generate 500 MW at the Tolk 1 generating unit for HE 1400 on that same day, but it actually generated 490 MW, the 10 MW imbalance would be multiplied by the LIP ($62.44 per MWh) to calculate the generator imbalance charge. In this scenario, SPS would have purchased 74 MW on the load side for $4,620.56 (74 MW* $62.44/MWh) and purchased 10 MW on the generator side for $624.40 (10 MW * $62.44/MWh). The imbalance amounts may be positive or negative for both generation and load volume. The short balancing positions are net payers to the long balancing positions.

The SPP is responsible for accounting and settling all EIS transactions. Participants with both load and resources have the hourly imbalance settlement for both load and resources netted prior to invoicing. The SPP calculates hourly settlements with weekly invoicing. Invoices include eight different charge types discussed below.

Q. Please provide an overview of the settlement process in the SPP EIS market.

A. Currently, the SPP settles all charges and credits with market participants through eight unique charge types included in Attachment AE (Energy Imbalance Service Market) of the SPP Regional OATT. A true and correct copy of Attachment AE to the SPP OATT is included as Attachment RMS-5. Each market participant, including SPS, receives an initial settlement statement listing all charges by charge type seven days after each operating day. Final settlement statements are issued 47 days after the operating day. The SPP continues to resettle a given operating day up to 12 more times, every 30 days after final to capture any granted disputes between market participants.

The following are the types of charges used to settle within the SPP:

a. *Energy Imbalance.* An energy imbalance charge is calculated for each hourly settlement interval based on the difference between the scheduled and actual withdrawal of energy for load, or the difference between the scheduled and actual output of a generator.

b. *Disgorgement.* The purpose of the charge is to prevent the market participants from gaining market advantage by arbitraging LIP values, which is possible for those that own generation and load assets. The SPP assesses an Over Scheduling or Under Scheduling disgorgement charge to market participants owning both generation and load assets if the market participant has a 4 percent or greater load discrepancy between the actual metered MWh value and the scheduled MWh value for a given hour *and* there is a deviation between the load and generator LIPs.

   - *Over Scheduling.* Over Scheduling occurs when a market participant schedules more MW than its actual metered value for load.

   - *Under Scheduling.* Under Scheduling occurs when a market participant schedules less MW than its actual metered value for load.

c. *Uninstructed Deviation ("UD").* The SPP assesses a UD charge applied to market participants whose resources operate outside a defined operating tolerance. The operating tolerance is intended to allow the SPP to maintain the efficiency of the EIS dispatch and provide additional financial incentives for resources to perform within an acceptable range when offered for SPP dispatch.

d. *Revenue Neutrality Uplift ("RNU").* For the SPP to remain revenue neutral for each hour that is settled within the EIS market, the SPP applies an uplift procedure to either recover or refund any residual dollars not accounted for under any other charge. The uplift and its application are based on each settlement location's absolute MW hours in the same time frame where the cause for uplift occurred. All MW hours generated, purchased, and interchanged coincident in the hour(s) in which revenue neutrality was breached are allocated a share of the uplift expense.

e. *Losses*. These charge types are paid on through and out transactions and seeks to recover the cost of supplying electrical losses in the market. These charge types ensure that market participants pay their fair share of the cost to generate power required to cover losses. The physics around delivery of energy on transmission lines has not changed since the start of the EIS market. A market participant has the two options: to either purchase losses from the market or self-generate energy to cover losses.

- *Self Provided Losses.* The market participant purchases or generates additional MW to cover loss.

- *Financially Settled Losses.* The market participant purchases losses from the market and the charge is calculated based on the MW of the transaction, the LIPs and the transmission loss percentage of each transmission provider. The SPP generated a loss matrix on a seasonal basis to reflect the losses for each Transmission Owner.

f. *Miscellaneous.* The Miscellaneous Charge is assessed for ad-hoc situations that occur where a charge or credit must be assessed for which there is no other applicable charge type. This could be due to resettlement of inappropriately calculated charges from a prior bill or to reconcile settlement disputes between counterparties. This charge type is typically zero for a given month.

Q. Will the charge types change with the modifications to the EIS market Mr. Grant describes?

A. Yes. Under the new market structure, SPP will identify approximately 60 charge types. However, these are not new charges per se. Rather, they are a more discrete and transparent identification of existing charges.

Q. Has SPS quantified the energy charges and revenues?

A. Yes. Please refer to Attachment RMS-6. SPS does not budget each of charge types. Accordingly, I have provided the 2012 net balance for each type.

IV. NERC FEES

Q. What topics do you cover in this section of your testimony?

A. I explain and quantify the level of the NERC fees SPS pays to the SPP.

Q. What are NERC fees?

A. SPS pays NERC fees to the SPP RE, as well as to the NERC. NERC develops and enforces Reliability Standards; monitors the bulk power system; assesses adequacy annually through a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel.

The SPP RE, which is an electric reliability organization ("ERO") fulfills the functions and duties specified in the SPP Regional Delegation Agreement with NERC, which was most recently approved by the FERC in 2010. As a NERC Regional Entity, the SPP RE promotes and works to improve the reliability of the bulk power system ("BPS"). Specifically, the SPP RE is responsible for developing regional reliability standards, monitoring and enforcing registered entity compliance with reliability standards, and assessing and evaluating BPS reliability. The SPP RE provides technical expertise and assistance to BPS owners, operators and users, in particular to the approximately 130 registered entities located within the SPP RE's footprint, an eight-state area that consists of all or portions of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New

Mexico, Oklahoma, and Texas. The SPP RE allocates fees to SPS and other entities on a load ratio share basis.

The separate fees paid to the SPP and NERC cover the specific functions and duties provided by each entity. Each incurs operating expenses associated with those functions, for which these charges are assessed.

Q. Would SPS have to pay these NERC fees to the SPP RE even if SPS were not under the SPP OATT?

A. Yes. As acknowledged by the Stipulation (Section 1.b) and consistent with NERC's authority under the Energy Policy Act, NERC has designated certain responsibilities to the SPP RE and assigned SPS to the SPP RE. Even if SPS were not a member of the SPP RTO, SPS would have a continuing obligation to pay its share of NERC fees to the SPP RE.

Q. How does NERC allocate its costs?

A. NERC allocates its costs among the EROs by each ERO's load ratio share as a percentage of total load in the entire United States. Then the charges allocated to the SPP RE are allocated among the load serving entities, on a load ratio share. For 2013 assessments, the SPP RE load ratio share for the United States load is 5.462 percent. The SPS load ratio share for the SPP RE's portion is 7.782 percent of all loads in the SPP RE footprint.

Q. How does the SPP RE allocate its costs?

A. Similar to NERC, the costs are allocated on a load ratio share basis. In particular, the allocation is based upon SPS's load relative to the total load of the SPP members.

Q. Has SPS quantified its NERC fees?

A. Yes. SPS has forecasted the 2013 and 2014 level of NERC fees.

Q. How did SPS determine the 2013 and 2014 amount of NERC fees?

A. To arrive at an estimate of total NERC fees, SPS took the first quarter assessment for 2012 and multiplied it by four to arrive at an estimate for the full 2012:

Fee Type	First Quarter 2012 Actual	Multiplied by 4
NERC	$61,131	$244,524
SPP RE	$228,640	$914,562
Total		$1,159,086

SPS then determined budget amounts for 2013 by increasing the 2012 amount for NERC and SPP RE costs by 5 percent respectively:

Fee Type	2012 Estimate	2013 amounts
NERC	$244,524 * (0.05)	$256,750
SPP RE	$914,562 * (0.05)	$960,290
Total		$1,217,040

SPS then took the resulting amounts for 2013 and increased them by 5 percent and 10 percent respectively for NERC and SPP RE costs.

Fee Type	2012 Estimate	Test Year Amount
NERC	$269,587 * (0.05)	$269,587.75
SPP RE	$960,290 * (0.10)	$1,056,318.97
Total		$1,325,907.00

Q. Are the percentage increases for 2013 and 2014 reasonable?

A. Yes. At the time the NERC fees budget was created, Xcel Energy reviewed the cost data available at the time from NERC, the SPP RE, as well as the Western Electric Coordinating Council ("WECC"). At the time, NERC forecasted a 2 percent increase in costs from 2012 to 2013, WECC forecasted an increase of 17 percent, and the SPS RE had experienced an increase of 15 percent from 2011 to 2012. Thus, the use of a 5 percent increase for 2013 and a 5 percent and 10 percent increase for 2014 was reasonable based on the ranges of increases known or reasonably expected by SPS.

V. THE COMMISSION'S RATE AND REGULATORY AUTHORITY

Q. What topic do you discuss in this section of your testimony?

A. I discuss the Commission's rate and regulatory authority over SPS's New Mexico retail operations in conjunction with SPS's participation in the SPP.

Q. Does the Commission retain authority over the transmission and generation components of SPS's bundled New Mexico retail jurisdictional revenue requirement while SPS is a member of the SPP?

A. Yes. SPS's participation in the SPP does not divest the Commission of authority over any of the transmission or generation components of SPS's bundled New Mexico retail rates. The Commission continues to have authority to determine the just and reasonable level of fuel and purchased power costs in SPS's New Mexico retail base rates and the just and reasonable level of costs recovered through SPS's FPPCAC. In addition, the Commission continues to have the authority to determine the just and reasonable level of transmission and generation plant to include in SPS's New Mexico retail rate base and the weighted average cost of capital (that is, the rate of return) applied to SPS's New Mexico retail rate base. The Commission also retains authority to determine the just and reasonable level of transmission-related and generation-related expenses in SPS's New Mexico retail revenue requirement that SPS does not incur under a FERC tariff. But for those transmission-related and generation-related expenses in SPS's New Mexico retail revenue requirement that SPS does incur under a FERC tariff (such as the charges I discussed earlier in my testimony), the Commission retains authority over whether it is reasonable for SPS to incur those expenses, but not over the rates or charges SPS pays under the FERC tariff.

Q. Does the Commission retain authority over SPS's requests for location approval and for certificates of public convenience and necessity ("CCNs") for SPS's transmission and generation facilities located in New Mexico while SPS is a member of the SPP?

A. Yes. SPS's participation in the SPP does not change SPS's obligations regarding location approval and CCNs under the PUA and Commission rules. SPS is still obligated to request location approval and CCNs for transmission and generation facilities as set out in the PUA and the Commission's rules.

Q. Does the Commission retain the authority to protect SPS's New Mexico retail customers regarding SPS's New Mexico retail operations while SPS is a member of the SPP?

A. Yes. The Commission continues to have the authority over SPS's New Mexico retail operations. SPS's participation in the SPP does not divest the Commission of authority to protect SPS's New Mexico retail customers.

VI. CERTAIN REPORTING REQUIREMENTS OF THE STIPULATION

Q. Does the Stipulation identify any reporting or notification requirements?

A. Yes. The Stipulation outlines the following reporting requirements (in addition to the requirement for this Interim Report):

- Section 3: Changes to the SPP Administrative Fee During Interim Period;
- Section 5: Change in Membership or Load Functions of SPP RTO;
- Section 9: Authority of Commission to Order Transmission or Associated Substation or Upgrades;
- Section 11: Annual Report; and
- Section 13: Participation in the SPP Energy Imbalance Service Market; Other Markets.

In this section of my testimony, I discuss the reports and notice SPS has filed with the Commission as required by Sections 3 and Section 11 of the Stipulation.

SPS has not filed any reports or notices under Sections 5 and 9 of the Stipulation because the actions that would require these filings have not occurred. In regard to Section 13 of the Stipulation, SPS is providing notice of its participation in the SPP Integrated Marketplace as part of this Interim Report. Mr. Grant discusses the Integrated Marketplace in his direct testimony.

Q. Please discuss the reporting requirements related to the SPP Administration Fee (Section 3 of the Stipulation).

A. Section 3 of the Stipulation requires SPS to submit a pleading to the Commission if the SPP Administration Fee (Schedule 1-A to the SPP OATT), 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.

Q. Has SPS been required to make any filings related to Section 3 of the Stipulation?

A. Yes. SPS has made one filing, consistent with Section 3 of the Stipulation, which is Attachment RMS-7 to my direct testimony.

Q. What is SPS's obligation under Section 11 of the Stipulation?

A. Consistent with Section 11 of the Stipulation, SPS is required to provide an annual report to the Commission by June 1 of each year. Specifically, the annual report is required to include the following information: (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.

Q. Has SPS complied with this requirement?

A. Yes. Please refer to Attachment RMS-8 for the annual reports filed with the Commission.

VII. <u>CONCLUSION</u>

Q. Were Attachments RMS-1 through 4 and RMS-6 prepared by you or under your direct supervision and control?

A. Yes.

Q. Are Attachments RMS-5, RMS-7, and RMS-8 true and correct copies of the documents you describe in your testimony?

A. Yes.

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

A. Yes.

Southwestern Public Service Company
Allocation of SPP Charges to NM Retail
For CY 2013 and 2014

Line No.	Description	Allocator Description	(A) Allocator (%)	(B) 2013 Total	(C) = (A) * (B) 2013 NM Retail	(D) 2014 Total	(E) = (A) * (D) 2014 NM Retail
1	Base Plan (Sch. 11)	12CP-TRAN	16.06%	$ 45,056,305	$ 7,236,990	$ 94,707,137	$ 15,211,957
2	Reserve Sharing	12CP-TRAN	16.06%	35,062	5,632	35,062	5,632
3	Sch 12 FERC Fees (Retail Only)	RETAIL-TRAN	25.87%	1,370,485	354,541	1,400,947	362,421
4	Sch 1A Admin - 561.4 (Retail Only)	RETAIL-TRAN	25.87%	4,034,272	1,043,655	4,659,186	1,205,319
5	Sch 1A Admin - 561.8 (Retail Only)	RETAIL-TRAN	25.87%	562,415	145,495	740,989	191,692
6	Sch 1A Admin - 575.7 (Retail Only)	RETAIL ENERGY	24.96%	2,624,602	655,226	3,457,947	863,269
7	Total			$ 53,683,140	$ 9,441,539	$ 105,001,267	$ 17,840,290

Southwestern Public Service Company
Calculation of SPP Schedule 11 Costs
For 2014

Line No.		A	B	C
1	**SPS Zonal ATRR**			
2		**SPP Revenue Requirement**		
3				
4	Base Plan	$ 32,532,420		
5	(prior to and including June 19, 2010 NTCs)			
6				
7	Base Plan - Highway/Byway Funding	14,051,996		
8	(after June 19, 2010 NTCs)			
9		$ 46,584,416		
10				
11				
12	**SPS Region - Wide ATRR**			
13		**SPP Revenue Requirement**	**LRS**	**SPS Share**
14				
15	Base Plan	$ 97,559,309	12.7886%	$ 12,476,470
16	(prior to and including June 19, 2010 NTCs)			
17				
18	Base Plan - Highway/Byway Funding	104,205,428	12.7886%	$ 13,326,415
19	(after June 19, 2010 NTCs)			
20				
21	Balanced Portfolio	113,517,403	12.7886%	$ 14,517,287
22				
23	CWIP	61,011,752	12.7886%	$ 7,802,549
24				
25		$ 376,293,892		$ 48,122,721
26				
27				
28	**Total SPP Schedule 11 Costs for 2013**			
29	Zonal Schedule 11 Costs (Line 9, Column A)	$ 46,584,416		
30	Regional Schedule 11 Costs (Line 25, Column C)	48,122,721		
31	Total SPS SPP Schedule 11 Costs	$ 94,707,137		

Southwestern Public Service Company
Allocation of SPP Charges to NM Retail
For CY 2013 and 2014

Line No.	Description	Allocator (Description)	(A) Allocator (%)	(B) Total	(C) = (A) * (B) NM Retail
1	PTP Transmission Service	12CP TRANS	16.06%	$ 4,698,000	$ 754,598
2	PTP Schedule 1	PIS TRANS	17.05%	1,856,280	316,570
3	PTP Schedule 2	12CP PROD	15.88%	1,329,767	211,164
4	Network Base Plan Upgrade	12CP TRANS	16.06%	79,874,337	12,829,498
5	PTP Base Plan Upgrade	12CP TRANS	16.06%	670,000	107,616
6	Total			$ 88,428,384	$ 14,219,445

Southwestern Public Service Company
Wheeling Revenues (Total SPS)
Test Year Level and Allocator

Line No.	FERC Acct	Account Description	Allocator
1	45605	Transmission Service	12-CP Transmission Allocator
2	45606	Transmission Service	12-CP Transmission Allocator
3	45607	Transmission Service	Eliminated; Relates to Provision of Network Service
4	45609	DA Transmission & Wholesale Metering	Direct Assign to Wholesale
5	45612	Schedule 1 - Scheduling	Eliminate Network; Assign Remaining on PIS-TRANS Allocator
6	45614	Schedule 2 - Reactive	Eliminate Network; Assign Remaining on12-CP Prod Allocator
7	45616	Schedule 3 - Regulation and Frequency Response Service	Direct Assign to Wholesale
8	45622	Schedule 5 - Spinning Reserve	Direct Assign to Wholesale
9	45624	Schedule 6 - Supplemental Reserve	Direct Assign to Wholesale
10	45626	Wholesale FERC Assessment	Direct Assign to Wholesale
11	45628	Wholesale Generator Step-Up	Direct Assign to Wholesale
12	45669	Base Plan Upgrade (PTP)	Credit Using 12-CP Transmission Demand
13	45671	Schedule 1	Eliminated; Relates to Provision of Network Service
14	45673	Base Plan Upgrade (Network)	Credit Using 12-CP Transmission Demand
15		**Total**	

ATTACHMENT AE

Energy Imbalance Service Market

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

Attachment AE
Table of Contents

1. Introduction

This Attachment sets forth the scheduling and dispatching responsibilities of the Transmission Provider and Market Participants relating to the provision of Energy Imbalance Service and sets forth the operation, pricing and settlement of the market for Energy Imbalance Service (EIS). This Attachment addresses the three time frames that are pertinent to the administration of the Energy Imbalance Service market: Day-Ahead Period, Hour-Ahead Period and Real-Time Period.

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

1.1 Definitions

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

1.1 Definitions A

Adjusted Net Scheduled Interchange

Net Scheduled Interchange as adjusted for EIS Market dispatch instructions, reserve sharing schedules, and inadvertent interchange payback schedules.

Ancillary Service Plan

A plan submitted by a Market Participant with Schedule 3, Schedule 5 and Schedule 6 obligations to meet its next day obligations and current day obligations.

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

1.1 Definitions B

Behind The Meter Generation:

Behind The Meter Generation refers to a generation unit that is connected on the load side of a load Meter Settlement Location and is agreed to by the load Market Participant that is the registered owner of the Meter Settlement Location to serve all or part of its capacity, energy or Ancillary Service needs.

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

1.1 Definitions C

Confidential Information

As referenced within Attachments AE, AF and AG to this Tariff, information containing or revealing:

(a) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant that is conspicuously designated as Confidential Information in writing, on each page of the document, by Disclosing Party at the time the information is provided to Receiving Party, whether conveyed electronically, in writing, through inspection, or otherwise;

(b) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern,procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant that is provided orally and designated as Confidential Information, by Disclosing Party at the time the information is provided to Receiving Party;

(c) Any customer information designated by the customer as proprietary, unless the customer has authorized the release for public disclosure of such information;

(d) Any software, products of software or other vendor information that SPP is required to keep confidential under its agreements.

Confidential Information does not include Critical Energy Infrastructure Information ("CEII") materials as designated by FERC, which must be obtained in accordance with FERC regulations.

Controllable Load

A registered, measurable load that is capable of being reduced at the instruction of the SPP Operator and subsequently increased at the instruction of the SPP Operator in order to provide a dispatchable quantity in the form of a demand response Resource. A Controllable Load must be associated with a demand response Resource.

Coordinated Flowgate

A flowgate defined within a joint operating agreement between the Transmission Provider and another transmission provider as being affected by the transmission of energy on either party's transmission system.

Effective Date: 7/26/2010 - Docket #: ER12-526

1.1 Definitions D

Day-Ahead Period

The time period starting at 0700 and ending at 1530 Central Prevailing Time of the day prior to the Operating Day.

Disclose or Disclosure

To, directly or indirectly, disclose, reveal, distribute, report, publish, or transfer Confidential Information to any entity other than to the Disclosing Party which provided the Confidential Information.

Dispatch Interval

The interval for which the Transmission Provider issues dispatch instructions for Energy Imbalance Service. The Dispatch Interval is currently 5 minutes.

Dispatchable Resource

A Resource for which an Offer Curve has been submitted and that is available for dispatch by the Transmission Provider.

Dispatchable Maximum Limit

A Resource's economic maximum output selected by Market Participant for each Operating Hour, as identified in the Resource Plan, reduced by the sum of the megawatt amounts of Schedule 3, Schedule 5 and Schedule 6 Service assigned to that Resource, as identified in the Ancillary Services Plan. For a Self-Dispatched Resource, the Dispatchable Maximum Limit equals the sum of all the schedules sourcing from that Resource.

Dispatchable Minimum Limit

A Resource's economic minimum output selected by Market Participant for each Operating Hour, as identified in the Resource Plan, increased by the megawatt amount of Schedule 3 Service assigned to that Resource, as identified in the Ancillary Services Plan. For a Self-

Dispatched Resource, the Dispatchable Minimum Limit equals the sum of the schedules sourcing from that Resource.

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

1.1 Definitions E

Energy Imbalance Service

The Ancillary Service defined under Schedule 4 to this Tariff.

Energy Imbalance Service Charge/Credit

A Market Participant's hourly charges and credits associated with its Imbalance Energy at a Settlement Location.

Energy Imbalance Service Uplift Charge/Credit

A Market Participant's hourly charge associated with an EIS Market revenue shortfall that is created when the total of all Energy Imbalance Service Credits is greater than the total of all Energy Imbalance Service Charges in an hour or a Market Participant's hourly credit associated with an EIS Market revenue excess that is created when the total of all Energy Imbalance Service Charges is greater than the total of all Energy Imbalance Service Credits in an hour.

Energy Imbalance Service Uplift Obligation

An hourly value in megawatts per hour calculated by the Transmission Provider for each Market Participant that is utilized by the Transmission Provider to determine each Market Participant's Energy Imbalance Service Uplift Charge/Credit.

Energy Obligation Deficiency

A condition created, either at the Market Participant level or Balancing Authority level, when the sum of applicable Resource Maximum Economic Limits in an hour is less than the applicable load forecast as adjusted for third party schedules in that hour.

Energy Obligation Excess

A condition created, either at the Market Participant level or Balancing Authority level, when the sum of applicable Resource Minimum Economic Limits in an hour is greater than the applicable load forecast as adjusted for third party schedules in that hour.

Energy Schedule

A set of hourly energy injection and withdrawal values, in megawatts per hour, submitted by Market Participants, at valid sources and sinks.

Exigent Conditions

Period of time when Resource is online and unable to follow dispatch instructions due to sudden changes in Resource conditions or operating characteristics that prevent predictable Resource operation. This status shall be available only upon request and with Transmission Provider approval.

External Resource

A Resource, other than a Designated Resource, located outside of the SPP Market Footprint that is included in an SPP market Balancing Authority through an External Resource Pseudo-Tie.

External Resource Pseudo-Tie

A non-physical electrical interconnection point between balancing authorities, whereby all or a portion of an External Resource is electronically moved from one Balancing Authority to another Balancing Authority that is in the SPP Market Footprint. Energy delivered from an External Resource to the sink in the SPP Market Footprint is treated as a Balancing Authority interchange from the source Balancing Authority to the sink Balancing Authority.

1.1 Definitions H

Hour-Ahead Period

The time period following the close of the Day-Ahead Period and ending thirty minutes before the Operating Hour.

Hourly Uninstructed Deviation Megawatt

The average of the absolute value of a Resource's Uninstructed Deviation Megawatt for an Operating Hour.

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

1.1 Definitions I

Imbalance Energy

The amount of Energy Imbalance Service in megawatts per hour that is provided or consumed by a Market Participant at a Settlement Location in an hour.

Intermittent Resource

A Resource that meets all of the following criteria: a) the fuel source can not be stored, b) the output of the Resource is by nature weather-driven, and c) it has limited capabilities to be dispatched and to respond to changes in system demand and transmission security constraints.

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1.1 Definitions L

Locational Imbalance Price

The market clearing price for Energy Imbalance at a specific location which shall be equivalent to the marginal cost of serving load at that location as calculated by the Transmission Provider's security constrained economic dispatch algorithm.

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1.1 Definitions M

Manual Dispatch Instruction

A dispatch instruction issued manually to a Resource by the Transmission Provider to resolve a system reliability condition that cannot be resolved through the process described under Section 4.3 of Attachment AE.

Market Flow

The aggregate megawatt flow on a Coordinated Flowgate or a Reciprocal Coordinated Flowgate caused by Energy Schedules for native load, intra Balancing Authority Area Energy Schedules, inter Balancing Authority Area Energy Schedules that are sourced at Dispatchable Resources or load Settlement Locations and Energy Imbalance Service.

Meter Settlement Location

The effective point at which a Market Participant's registered load and Resources interchange energy with the EIS Market.

1.1 Definitions N

NERC Interchange Distribution Calculator (NERC IDC)

The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of interchange transactions over specific flowgates.

Net Energy Imbalance Service Charge/Credit

The sum of a Market Participant's Settlement Location specific Energy Imbalance Service Charge/Credits in an hour.

Net Actual Interchange

The algebraic sum of all energy flowing into or out of a Settlement Area during a Settlement Interval.

Net Scheduled Interchange

The algebraic sum of all Energy Schedules into or out of a Control Area.

Non-Dispatchable Resource

A Resource meeting any of the following conditions: (a) operating in Shut-down Mode; (b) operating in Start-up Mode; (c) operating in Testing Mode; (d) operating under Exigent Conditions; (e) is an Intermittent Resource; or (f) is a Qualifying Facility.

1.1 Definitions O

Offer Curve

A set of price/quantity pairs associated with a Dispatchable Resource that represents the prices and amounts of dispatchable energy or curtailable consumption offered to the Transmission Provider for the provision of Energy Imbalance Service.

Operating Day

The daily period beginning at midnight for which transactions within SPP are scheduled.

Operating Hour

A 60 minute period of time during the Operating Day corresponding to a clock hour.

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

1.1 Definitions P

Physical Schedule

An Energy Schedule that has a source that is a Self-Dispatched Resource or that is scheduled into, out of, or through the SPP Market.

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

1.1 Definitions Q

Qualifying Facility

A generating facility which meets the requirements for Qualifying Facility status under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and part 292 of the Commission's Regulations (18 C.F.R. Part 292), and which has obtained certification of its Qualifying Facility status.

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

1.1 Definitions R

Real Time Period

The time period during an Operating Hour in which the Transmission Provider or the Control Area operator balances the system by deployment of energy from Energy Imbalance Service and Schedule 3, Schedule 5 or Schedule 6 Services.

Reciprocal Coordinated Flowgate

A Coordinated Flowgate defined within a joint operating agreement between the Transmission Provider and another transmission provider as being affected by the transmission of energy on both of their respective transmission systems.

Resources

Assets which are defined within the EIS Market systems which inject energy into the transmission grid, or which reduce the withdrawal of energy from the transmission grid, and may be self-dispatched or directly dispatchable by the Transmission Provider. These Resources may include generation or Controllable Load that is part of the SPP Market Footprint through its physical interconnection and External Resources included in the SPP Market Footprint through an External Resource Pseudo-Tie.

Resource Plan

A Market Participant's plan to meet its energy obligations including specification of Resource operating characteristics.

1.1 Definitions S

Scheduled Generation

The amount of energy scheduled to be injected at a Settlement Location pursuant to submission of an Energy Schedule that is used in the calculation of a Market Participant's Imbalance Energy at a Settlement Location. This value is assumed to be a negative value for settlement purposes.

Scheduled Load

The amount of energy scheduled to be withdrawn at a Settlement Location pursuant to submission of an Energy Schedule that is used in the calculation of a Market Participant's Imbalance Energy at a Settlement Location. This value is assumed to be a positive value for settlement purposes.

Self-Dispatched Resource

A Resource that is not available for economic dispatch by the Transmission Provider to support market operations.

Settlement Area

An area within a single Control Area in the Transmission System for which interval metering can account for the net injections and net interchange associated with that area.

Settlement Area Metered Net Interchange

The algebraic sum of all energy flowing into or out of a Settlement Area during an hour.

Settlement Area Net Load

The sum of, as adjusted to account for Transmission System losses associated with through or out service as specified in Attachment M, (a) net injections at each Settlement Location within the Settlement Area and (b) Settlement Area Metered Net Interchange.

Settlement Location

Locations defined for the purpose of commercial operations and settlement. A Settlement Location can be either a single Meter Settlement Location or, for load, an aggregation of Meter Settlement Locations within one Settlement Area as designated during the asset registration process by a Market Participant serving load.

Shut-down Mode

A period of time after the Resource operates below its Minimum Capacity Operating Limit as indicated in the Resource Plan, but not to exceed one hour before and after the scheduled time for a Resource to be removed from the electrical grid.

SPP Market Footprint

The Loads and Resources that are located within a Balancing Authority Area subject to Attachment AN under this Tariff.

Start-up Mode

The period of time before the Resource reaches its Minimum Capacity Operating Limit as indicated in the Resource Plan, but not to exceed two hours before and after the scheduled time for a Resource to synchronize to the grid.

State Estimator

A standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable.

1.1 Definitions T

Test Mode

Operation of new facilities not yet commercially accepted by the owner of the Resource that is designed to assist in commercial acceptance testing of the Resource by the owner or, the operation of a Resource that has been off-line due to an extended maintenance period. This operation must be coordinated with the Transmission Provider to the extent possible.

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1.1 Definitions U

Uninstructed Deviation Charge

A Market Participant's charge associated with a Resource that is determined to have operated outside an acceptable operating tolerance relative to dispatch instructions in accordance with procedures set forth in this Tariff.

Uninstructed Deviation Megawatt

The megawatt amount by which a Resource's actual output in a Dispatch Interval is above or below that Resource's acceptable operating range.

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

1.1 Definitions V

(Reserved for Future Use)

Effective Date: 7/26/2010 - Docket #: ER12-526

1.2 Market Participant Obligations

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

1.2.1 Service Agreement

Each Market Participant must execute the Service Agreement specified in Attachment AH. If the Market Participant fails or refuses to execute this service agreement the Transmission Provider will file an unexecuted agreement with the Commission in accordance with Section 1.2.2 (g).

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

1.2.2 Application and Asset Registration

(a) Applications for a Market Participant to provide services in the EIS Market must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 12.3 of the Market Protocols. Completed applications must contain the required information specified under the application procedures specified in the Market Protocols. *New Market Participants will follow the timeframe as specified in Section 12.4 in addition to the detailed model update timing requirements in Section 12.3 of the EIS Market Protocols.*

(b) As part of the application process, Market Participants must register all load, including applicable load associated with Grandfathered Agreements, and Resources with the Transmission Provider in accordance with the registration process specified in the Market Protocols.

(c) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Settlement Locations associated with their load assets. Such a Settlement Location is used for settlements purposes only and the Meter Settlement Locations being aggregated must be within a single Settlement Area.

(d) For registration of jointly owned Resources, Market Participant owners:

- must register the entire ownership of a jointly owned Resource included within a Balancing Authority Area inside the SPP Region, including ownership that is not associated with a Market Participant, as either a single Resource or multiple Resources; and
- may specify a Designated Agent for the purposes of submitting Offer Curves.

(e) For registration of jointly owned Resources, Market Participant owners:

- must register the entire ownership of a jointly owned Resource included within a Balancing Authority Area inside the SPP Region, including ownership that is not associated with a Market Participant, as either a single Resource or multiple Resources; and
- may specify a Designated Agent for the purposes of submitting Offer Curves.

If the jointly owned Resource is registered as multiple Resources, the Transmission Provider shall treat each registered portion of the joint owned Resource as an independent Resource for the purposes of EIS Market participation.

For jointly owned Resources, the operating owner's meter agent shall be the meter agent for that jointly owned Resource unless a jointly owned Resource owner designates a different meter agent for its share of the Resource.

(f) Market Participants may subsequently modify their initially registered assets once their participation in the EIS Market has commenced in accordance with the asset registration procedures specified in the Market Protocols.

(g) All loads and all Resources, excluding Behind The Meter Generation less than 10 MW, must register. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the EIS Market or subject the Qualifying Facility to any charges or payments related to the EIS Market.

(h) A Market Participant wishing to offer an External Resource in the EIS Market will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlines in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the EIS Market, except as provided in this Attachment AE.

(i) A Market Participant wishing to offer *Controllable Load in the form of* a *demand response R*esource in the EIS Market must include in its application and registration a certification that participation in the EIS Market by its *demand response R*esource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 1.2.10 of this

Attachment AE, an aggregator of retail customers ("ARC") wishing to offer Controllable Load in the form of a demand response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. *Demand response R*esources must meet all application, registration and technical requirements applicable to other resources offering imbalance energy in the EIS Market. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the EIS Market in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(j) *An ARC offering Controllable Load of one or more end-use retail customers as a demand response resource in the EIS Market must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 1.2.10 of this Attachment.*

1.2.3 Market Manipulation

Market Participants shall not engage in any market manipulation activities. Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electric products are prohibited. Such activities include but shall not be limited to the activities specified in Section 4.3 of Attachment AG.

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

1.2.4 Resource Plans and Energy Schedules

Market Participants with assets in the SPP Region that have been registered pursuant to Section 1.2.2 shall submit to the Transmission Provider Resource Plans to meet all their energy obligations in accordance with the timelines and data requirements specified in Section 2.2 of this Attachment AE. Market Participants who submit an Energy Schedule to the Transmission Provider shall follow the timelines and data requirements specified in Section 2.2 of this Attachment AE.

1.2.5 Ancillary Service Plans

Market Participants with obligations to supply Schedule 3, Schedule 5 and/or Schedule 6 service to load within SPP shall submit to the Transmission Provider an Ancillary Service Plan to meet their Schedule 3, Schedule 5 and Schedule 6 obligations in accordance with the timelines and data requirements specified in Section 2.3 of this Attachment AE.

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

1.2.6 Resource Offer Curves

Market Participants electing to submit Offer Curves to the Transmission Provider for the provision of Energy Imbalance Service shall submit such Offer Curves in accordance with the timelines and data requirements specified in Section 2.5 of this Attachment AE. For the first 90 days commencing with the EIS Market Effective Date, Market Participants must submit Offer Curve prices that are less than or equal to $400/megawatt-hour. Beginning 91 days after the EIS Market Effective Date, Market Participants must submit Offer Curve prices that are greater than or equal to negative $1000/megawatt-hour and less than or equal to $1000/megawatt-hour until such time as the Transmission Provider demonstrates in a filing with the Commission that sufficient Controllable Load exists in the EIS Market to allow a higher Offer Curve price limit or removal of the Offer Curve price limit. Beginning with the EIS Market Effective Date, Offer Curves shall be subject to the provisions of Section 3.2.4 of Attachment AF to this Tariff.

Effective Date: 4/4/2011 - Docket #: ER12-526

1.2.7 Scheduling and Dispatch

Market Participants shall, where applicable:

(a) Follow the Transmission Provider's dispatch instructions where such dispatch instructions are described under Section 4.1 of Attachment AE;

(b) Incorporate the Transmission Provider's Adjusted Net Scheduled Interchange, as calculated pursuant to Section 4.1, into their respective Control Area energy management systems;

(c) Report Resource Plan changes to the Transmission Provider throughout the Operating Day resulting from changes in Resource availability;

(d) Report changes to Ancillary Service Plans resulting from changes in Resource availability to the Transmission Provider; and

(e) Abide by the procedures set forth in the Market Protocols.

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

1.2.8 Energy Imbalance Service Settlement

Market Participants, or their designated Meter Agent, shall submit to the Transmission Provider for each hour of the Operating Day meter data representing the actual generation output and actual load consumption, or where actual data is not available estimates thereof, associated with their registered load and Resources in accordance with the timelines specified in the Market Protocols. A Market Participant may designate any qualified entity to perform the meter agent function or perform this function on its own behalf.

Any entity performing the meter agent function for a Market Participant must execute the Meter Agent Agreement specified in Attachment AM prior to performing such function.

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

1.2.9 Calculation of Real-Time *Controllable Load* from Demand Response Resources

The demand response provided by the Controllable Load associated with a demand response Resource is sent directly to the Transmission Provider. This value will represent the actual net generation.

Effective Date: 12/5/2011 - Docket #: ER12-550

1.2.10 Aggregation of Controllable Load as a Resource

For purposes of participation in the SPP EIS Market, an ARC may aggregate Controllable Load of: (1) end-use retail customers of utilities that distributed more than 4 million MWh in the previous fiscal year, unless precluded by the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s); and (2) end-use retail customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority, including any state-approved retail tariff(s), affirmatively permits such customer's demand response to be bid into the SPP EIS Market by an ARC. An ARC wishing to offer Controllable Load in the EIS Market must execute all agreements necessary to become a Market Participant and to participate in the EIS Market under the SPP Tariff and Attachment AE. ARCs shall be treated comparably to other Market Participants offering Resources in the EIS Market.

Aggregations pursuant to this section shall be subject to the following requirements:

(a) End-use customers aggregated into a single Resource must be located at the same electrically equivalent withdrawal point from the Transmission System and must be served by the same retail provider; and

(b) All end-use customers in an aggregation shall be specifically identified.

1.3 Transmission Provider Obligations

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

1.3.1 Market Protocols

The Transmission Provider shall prepare, maintain and update the Market Protocols consistent with this Tariff. The Market Protocols shall be posted on the SPP website.

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

1.3.2 Scheduling and Dispatch

The Transmission Provider shall evaluate Resource Plans submitted by Market Participants during the Day-Ahead Period and the Hour-Ahead Period in accordance with Sections 2 and 3 of this Attachment.

(a) In the Real-Time Period, the Transmission Provider shall dispatch Dispatchable Resources between their Dispatchable Minimum Limit and Dispatchable Maximum Limit to provide Energy Imbalance Service economically on the basis of least-cost, security-constrained economic dispatch and the prices and operating characteristics offered by Market Participants or based upon Manual Dispatch Instructions only during Emergency Conditions where such Emergency Conditions can not be resolved through the process described under Section 4.3 of Attachment AE.

(b) In the Real-Time Period, the Transmission Provider shall issue dispatch instructions to Self-Dispatched Resources in accordance with

  (i) the approved Resource Plan; and

  (ii) the approved Energy Schedules.

In addition, the Transmission Provider may issue Manual Dispatch Instructions to Self-Dispatched Resources only during Emergency Conditions where such Emergency Conditions can not be resolved through the process described under Section 4.3 of Attachment AE.

1.3.3 Ancillary Service Plans

(a) The Transmission Provider shall calculate the Schedule 3, Schedule 5 and Schedule 6 obligations for Market Participants in accordance with the procedures set forth in the SPP Criteria on a daily basis.

(b) The Transmission Provider shall evaluate the Ancillary Service Plan submitted by a Market Participant to ensure that the Market Participant has identified sufficient Resources or that the Market Participant has entered into bilateral transactions to meet its Schedule 3, Schedule 5 and Schedule 6 obligations for the next Operating Day.

1.3.4 Energy Imbalance Service Pricing

The Transmission Provider shall calculate a Locational Imbalance Price at each Settlement Location in accordance with Section 4.4 of this Attachment AE.

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

1.3.5 Energy Imbalance Service Settlements

The Transmission Provider shall calculate Energy Imbalance Service settlement quantities at each Settlement Location, calculate charges and credits associated with the provision of Energy Imbalance Service based upon the settlement quantities and the associated Locational Imbalance Prices in accordance with Section 5 of this Attachment AE and render invoices to Market Participants detailing net charges or credits associated with provision of Energy Imbalance Service in accordance with Section 6 of this Attachment AE.

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

1.3.6 EIS Market Participation Readiness

The Transmission Provider shall validate each Market Participant's ability to provide services in the EIS Market, as applicable. Such validation shall include verification that the Market Participant has met the technical and communications requirements for EIS Market participation specified in the Market Protocols and has met the credit requirements specified under the SPP Credit Policy.

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

1.3.7 Manage Inadvertent Interchange

The Transmission Provider shall manage the inadvertent interchange accounts for the SPP Region in accordance with the principles provided in section 2.6.

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

1.3.8 Self-Provision of Losses for Through and Out Transactions

The Transmission Provider shall identify the Designated Balancing Authority for purposes of accounting for self-provided losses relating to transactions through and out of the SPP Region. The Transmission Provider will permit all potential Designated Balancing Authorities to register a unique loss Settlement Location to be used exclusively for the purpose of receiving losses as the Designated Balancing Authority. The Locational Imbalance Price associated with that unique loss Settlement Location shall be the Locational Imbalance Price for the Designated Balancing Authority's load Settlement Location. Such loss Settlement Locations shall not have any associated metered Resources or Loads and shall not be subject to any of the scheduling requirements specified in Section 6.6 of the Market Protocols.

(a) Through Transactions

(i) Upon implementation of the EIS Market, American Electric Power ("AEP") shall serve as the Designated Balancing Authority for purposes of accounting for self-provided losses relating to transactions through the SPP Region and AEP shall designate a Settlement Location to which the Transmission Provider shall deliver self-provided loss energy associated with transactions through the SPP Region. After one year and with at least 120 days notice, the Designated Balancing Authority shall have the option to terminate this designation effective on the first day of a calendar month.

(ii) In the event the Designated Balancing Authority notifies SPP to terminate this designation, a subsequent Designated Balancing Authority will be selected and notified within 20 days by the Transmission Provider utilizing the following procedure:

(1) calculate the average cost of self-provided losses associated with transactions through and out of the SPP Region for the previous 12 month period as follows:

Average Cost of Self-Provided Losses = [sum of previous 12 months Self-Provided Loss Credits] / [sum of previous 12 months of Self-Provided Losses], where:

Self-Provided Loss Credits are payments to Market Participants associated with transactions through and out of the SPP Region as calculated in accordance with Section 4B.2 of Attachment M; and Self-Provided Losses are the total of all losses associated with all transactions through and out of the SPP system where such losses are specified on the transaction tag;

(2) calculate the average Locational Imbalance Price for each load Settlement Location for the previous 12 month period; and

(3) compare the Average Cost of Self-Provided Losses, as calculated under Section 1.3.8(a)(ii)(1), to the average Locational Imbalance Price of each load Settlement Location, as calculated under Section 1.3.8(a)(ii)(2), and select the Balancing Authority with the load Settlement Location with the average Locational Imbalance Price that is closest to the Average Cost of Self-Provided Losses, provided that such Balancing Authority's projected minimum hourly total Reported Load for the next calendar year is greater than or equal to 500 megawatts. Such selected Balancing Authority shall serve as the Designated Balancing Authority for at least one year and until the Designated Balancing Authority provides its notice of termination pursuant to Section 1.3.8(a)(i) and the Transmission Provider shall deliver self-provided loss energy associated with transactions through the SPP Region to such Designated Balancing Authority's associated Settlement Location.

(b) Out Transactions

The Designated Balancing Authority associated with transactions out of the SPP Region shall be the Balancing Authority associated with the transaction Point of Receipt. The Transmission Provider shall deliver self-provided loss energy associated with transactions out of the SPP Region to such Designated Balancing Authority's Settlement Location associated with the transaction Point of Receipt.

1.3.9 – Electronic Delivery of Data to the Commission

The Transmission Provider will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

Effective Date: 8/20/2012 - Docket #: ER12-2479-000

2. Day-Ahead Period Activities

The Transmission Provider and Market Participants shall adhere to the following scheduling procedures regarding development of the next day operating plan.

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

2.1 Transmission Provider Forecast Information

No later than 0730 Central Prevailing Time on the day prior to the Operating Day, the Transmission Provider shall:

(a) Develop an hourly load forecast for each Settlement Area, Balancing Authority and for the SPP Region for the next seven days. The Transmission Provider shall take into consideration load forecast information provided by Balancing Authorities in forming its forecast. The Transmission Provider shall provide these hourly load forecasts electronically for use by Market Participants in developing their Resource Plans and load forecasts; and

(b) Calculate each Market Participant's Schedule 3, Schedule 5 and Schedule 6 obligations for the next Operating Day and shall post these obligations electronically. Market Participant Schedule 3, Schedule 5 and Schedule 6 obligations shall be calculated by the Transmission Provider as specified in the SPP Criteria and this Tariff.

2.2 Resource Plan and Energy Schedule Submittal Requirements

No later than 1100 Central Prevailing Time on the day prior to the Operating Day, Market Participants must submit Resource Plans and load forecasts for each hour of the next Operating Day to the Transmission Provider. To the extent that the sum of Market Participants' load forecasts for each Settlement Area is significantly different than the Transmission Provider's Settlement Area load forecasts developed under Section 2.1, the Transmission Provider shall contact the applicable Market Participants to resolve the discrepancy. A Market Participant must submit a Resource Plan that provides a sufficient amount of available energy to meet all of the Market Participant's energy obligations, where such energy obligations are equal to the Market Participant's load forecast plus third party sales minus third party purchases. Market Participants must satisfy their energy obligations through any combination of: (1) scheduling energy from third parties, (2) planned operating levels of Self Dispatched Resources as identified in the Resource Plan or (3) by making its Resources available to the Transmission Provider for dispatch with sufficient dispatchable operating range, as identified in the Resource Plan, such that in aggregate, they are capable of producing sufficient energy to meet the Market Participant's energy obligations at all times. The Transmission Provider shall also calculate an energy obligation associated with each Balancing Authority for use in the analyses performed under Section 2.4 of Attachment AE that is equal to the Balancing Authority load forecast developed under Section 2.1 of Attachment AE plus third party sales minus third party purchases out of or into the Balancing Authority Area.

Market Participants may also submit Energy Schedules and such schedules must be submitted in accordance with the timelines set forth in Attachment P.

2.2.1 Market Participant's Resource Plan

A Market Participant's Resource Plan covers a rolling seven-day horizon (with hourly detail) beginning with the Operating Day and may be modified before each operating hour and is binding for that operating hour. Specifically, the Resource Plan contains entries for each Resource for each hour of the seven day horizon, and includes the following information:

- Resource ID
- Resource Type
- Planned Megawatts
- Minimum Capacity Operating Limit – Demand response Resources will submit a value of 0 MW for this field.
- Minimum Economic Capacity Operating Limit – Demand response Resources will submit a value of 0 MW for this field.
- Minimum Emergency Capacity Operating Limit – Demand response Resources will submit a value of 0 MW for this field.
- Maximum Capacity Operating Limit – For demand response Resources, Max MW will be the maximum amount of response or interruption that can be provided.
- Maximum Economic Capacity Operating Limit – For demand response Resources, this will be the maximum amount of response or interruption that can be provided under normal market operations. Must be equal to or less than the value provided for Maximum Capacity Operating Limit.
- Maximum Emergency Capacity Operating Limit – For demand response Resources, this will be the maximum amount of response or interruption that can be provided under emergency operating conditions. Must be equal to or greater than the value provided for Maximum Capacity Operating Limit.
- Ramp Rate
- Resource Status
- The Resource Plan may not be the only source of Resource data required by SPP, in its roles as the Regional Reliability Coordinator and Transmission Service Provider, for the purposes of maintaining system reliability and granting

transmission service. Market Participants with registered Resources, or the Balancing Authorities within which such Resources are located, may be requested to provide to SPP additional Resource information beyond that contained in the Resource Plan.

Effective Date: 7/26/2010 - Docket #: ER12-526

2.2.2 Market Participant's Energy Schedule

A Market Participant's Energy Schedule shall be submitted according to the following:

(a) Energy Schedules shall be submitted using the data formats and procedures defined in the Market Protocols.

(b) Such hourly Energy Schedules must specify a megawatt per hour amount of energy at the source, which may include self-provision of Transmission System losses, and a megawatt per hour amount of energy at the sink.

(c) Market Participants must associate Energy Schedules with a specified source and sink that are valid Settlement Locations in order for the Energy Schedules to be utilized in the calculation of Imbalance Energy.

(d) Market Participants that submit Energy Schedules are required to ensure that the total of the scheduled megawatt per hour injections submitted is equal to the total of the scheduled megawatt per hour withdrawals submitted plus self-provided Transmission System losses for through or out transactions per Attachment M.

(e) Market Participants that are parties to Grandfathered Agreements shall identify to the Transmission Provider which party is responsible for submission of Energy Schedules.

2.3 Ancillary Service Plans

Market Participants must submit Ancillary Service Plan information to meet their Schedule 3, Schedule 5 and Schedule 6 obligations, to the extent that such obligations exist, to the Transmission Provider no later than 1100 Central Prevailing Time on the day prior to the Operating Day. Ancillary Service Plans shall include identification of the Market Participant's Resources providing the Services and identification of any bilateral transactions that transfer these obligations to or from the Market Participant. A Market Participant's Ancillary Service Plan shall be submitted according to the following:

(a) Market Participants shall submit Ancillary Service Plans in accordance with the data formats and submittal procedures specified in the Market Protocols.

(b) Market Participants that are parties to Grandfathered Agreements shall Identify to the Transmission Provider which party is responsible for submitting Ancillary Service Plans related to such agreements.

2.4 Ancillary Service Plan and Resource Plan Evaluation

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

2.4.1 Evaluation of Ancillary Service Plan

No later than 1200 Central Prevailing Time on the day prior to the Operating Day, the Transmission Provider shall complete an evaluation of the Ancillary Service Plans submitted pursuant to Section 2.3 to verify that each Market Participant has met its Schedule 3, Schedule 5 and Schedule 6 obligations. If the Transmission Provider determines that a Market Participant has not met one or more of these ancillary service obligations, the Transmission Provider shall notify the Market Participant. The Market Participant shall modify its Ancillary Service Plan and/or its Resource Plan as necessary to meet its ancillary service obligations and shall submit such modifications to the Transmission Provider no later than 1300 on the day prior to the Operating Day. Such revisions shall be coordinated with the Transmission Provider.

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

2.4.2 Review and Assessment of Resource Plans

Prior to each Operating Day, the Transmission Provider shall assess the supply adequacy and deliverability of operating capacity scheduled in each Market Participant's Resource Plan. The Transmission Provider shall perform this assessment using the Supply Adequacy Analysis and Supply Deliverability Analysis described in (a) and (b) below respectively. If required, the Transmission Provider also may perform the Simultaneous Feasibility Test described in Section (c) below.

(a) Supply Adequacy Analysis

The inputs to the supply adequacy analyses shall be the load forecasts developed pursuant to Section 2.1 and submitted under Section 2.2, the Resource Plans submitted pursuant to Section 2.2, the energy obligations calculated under Section 2.2, and Ancillary Service Plans submitted pursuant to Section 2.3. The objective of performing the supply adequacy analysis is to ensure there is sufficient operating capacity scheduled so that the Transmission Provider may operate the system reliably to meet the load forecast. For each hour, the Transmission Provider shall determine if each Market Participant's energy obligation as set forth in Section 2.2 is: (i) less than the aggregate of the Dispatchable Maximum Limits; and (ii) greater than the aggregate of the Dispatchable Minimum Limits submitted in its Resource Plan. Similarly, for each Balancing Authority Area, the Transmission Provider shall determine if the Balancing Authority's energy obligation set forth in Section 2.2 is: (i) less than the aggregate of the Dispatchable Maximum Limits; and (ii) greater than the aggregate of the Dispatchable Minimum Limits submitted in all Market Participant Resource Plans in that area. If the Transmission Provider determines there is an Energy Obligation Deficiency or Energy Obligation Excess in any hour of the next Operating Day within a Balancing Authority Area, the Transmission Provider shall immediately notify those Market Participants within that Balancing Authority Area that have an Energy Obligation Deficiency or Energy Obligation Excess, as applicable, in that hour. Such Market Participant shall correct the deficiency or excess and resubmit revised plans and/or schedules to the

Transmission Provider by the later of 1700 on the day prior to the Operating Day or two hours following notification by the Transmission Provider.

(b) Supply Deliverability Analysis

The supply deliverability analysis shall be a day-ahead contingency analysis to assess the impact of any single transmission contingency 100 kV and above while monitoring all facilities 100 kV and above within the entire SPP Reliability Coordinator footprint and neighboring Balancing Authority Areas or Transmission Operator systems. During conditions where systems reliability is threatened, SPP shall notify and coordinate with the affected the Transmission Operators, Balancing Authorities, or Transmission Service Providers in determining appropriate control action.

(c) Simultaneous Feasibility Analysis

(i) The inputs to the simultaneous feasibility analyses shall be the load forecasts developed pursuant to Section 2.1, the Resource Plans submitted pursuant to Section 2.2, including any applicable Energy Schedules, Offer Curves submitted pursuant to Section 2.5 and Ancillary Service Plans submitted pursuant to Section 2.3. The simultaneous feasibility analysis determines the impacts of single transmission facility contingencies on a set of monitored transmission facilities.

(ii) To verify that the submitted Resource Plans and applicable Energy Schedules can be implemented reliably, the Transmission Provider shall determine if all constraints identified in the simultaneous feasibility analysis can be resolved through; (i) the simulated dispatch of Dispatchable Resources only; and (ii) simulation of potential impacts that a TLR may have on the constraint as described in the Market Protocols. If such constraints can be resolved, the Transmission Provider shall post a notification on its website identifying the projected constraint and that TLR may be necessary to resolve the issues in Real-Time.

(iii) If the Transmission Provider determines through the simultaneous feasibility analysis that the submitted Resource Plans cannot be implemented reliably, the Transmission Provider shall immediately notify the affected Market Participants that their plans are infeasible. The Transmission Provider shall determine each affected Market Participant's responsibility for resolving the infeasibility in accordance with the Market Protocols. Such Market Participants shall revise and resubmit their plans to the Transmission Provider by the later of 1700 on the day prior to the Operating Day or two hours following notification by the Transmission Provider.

Effective Date: 5/24/2012 - Docket #: ER12-430-002

2.4.3 Resubmission of Resource Plan or Ancillary Plan

To the extent the revised plans do not address the Energy Obligation Deficiency or Energy Obligation Excess condition within a Balancing Authority or the infeasibility, the Transmission Provider may:

(a) direct a Market Participant with an Energy Obligation Deficiency within the applicable Balancing Authority Area to commit additional Resources to correct the Energy Obligation Deficiency;

(b) direct a Market Participant with an Energy Obligation Excess within the applicable Balancing Authority Area to de-commit a Resource to correct the Energy Obligation Excess; or

(c) direct the applicable Market Participants to commit or de-commit Resources to alleviate constraint violations that have not been addressed within the applicable Market Participants plans.

If a Market Participant fails to follow the Transmission Providers instructions as described in Sections 2.4.3(a), 2.4.3(b) and 2.4.3(c), and such action causes an Emergency Condition during the Real-Time Period, the Transmission Provider shall submit a report of the Market Participant's actions to the Commission.

2.5 Resource Offers

(a) Market Participants must submit Offer Curves for each Resource that has been identified in the Market Participant's Resource Plan as available for dispatch by the Transmission Provider for the provision of Energy Imbalance Service. Offer Curves may be submitted as early as 7 days prior to Operating Day and may be submitted or modified up to forty-five minutes prior to the Operating Hour. Offer Curves shall be Resource specific and shall specify the amounts and prices of energy available for dispatch. The smallest increment of energy that may be specified in an Offer Curve shall be one megawatt per hour. To the extent that a Market Participant does not submit a new Offer Curve for a Resource identified in that Market Participant's Resource Plan as available for dispatch by the Transmission Provider, the Transmission Provider shall utilize the last valid Offer Curve submitted for the purposes of Resource dispatch.

(b) If a Market Participant is determined to have an Offer Capped Resource pursuant to Section 3.2.2 of Attachment AF to this Tariff, then the provisions of Section 3.2.4 of Attachment AF to this Tariff shall apply to that Resource's submitted Offer Curves.

(c) A Market Participant's Offer Curve is submitted with up to ten monotonically increasing pairs of MWh and price. The Offer Curve will include the following components:

- Date
- Hour Ending
- Resource
- Megawatts
- Price/MWh

2.6 Inadvertent Payback Schedules

The Transmission Provider shall maintain inadvertent accounts and administer inadvertent payback for all Control Areas participating in the SPP market. In doing so, SPP shall adhere to the following principles:

(i) Inadvertent payback shall be administered in accordance with NERC criteria, applicable joint operating agreements, and Good Utility Practice; and

(ii) Inadvertent payback decisions shall be made without regard to possible profits or losses resulting from changes in energy costs over time.

(a) Prior to implementation of the SPP Markets, the Transmission Provider shall establish, in consultation with each Control Area, its pre-market inadvertent interchange balance. After implementation of the SPP Markets, the Transmission Provider shall calculate the inadvertent payback schedules for each Control Area necessary to reduce these pre-market balances to zero over time. The Transmission Provider shall communicate these payback schedules to each affected Control Area. Such inadvertent payback schedules will be used in the calculation of the Control Areas Adjusted Net Scheduled Interchange value.

(b) After implementation of the SPP Markets, there will be no inadvertent interchange within the SPP Market. SPP shall manage inadvertent interchange for the SPP Market. All deviations from schedules with Market Participants will be settled financially as part of the Imbalance Energy settlements process. Each hour SPP shall sum the difference between actual and schedule net interchange of all Control Areas within SPP to determine the SPP inadvertent interchange. To payback the inadvertent interchange, SPP shall create an obligation in the security constrained dispatch requirements

3. Hour-Ahead Period Activities

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

3.1 Modifying Resource Plans, Ancillary Service Plans, and Offer Curves

Following the close of the Day-Ahead Period, Market Participants may amend the information submitted during the Day-Ahead Period as follows:

(a) Market Participants may submit new or revised Resource Plans for the next Operating Hour up to forty-five minutes prior to the Operating Hour;

(b) Market Participants may submit new or revised Energy Schedules to be approved by thirty minutes prior to the start of the Energy Schedule for Energy Schedules requiring NERC tags and may submit new or revised Energy Schedules to be approved by twenty minutes prior to the start of the Energy Schedule for Energy Schedules not requiring NERC tags. The last Energy Schedule approved prior to the start of the schedule shall become final and shall be utilized to determine the Market Participant's Scheduled Generation and Scheduled Load for the purposes of calculating a Market Participant's Imbalance Energy for the applicable Operating Hour and Settlement Location.

(c) Market Participants may submit new or revised Offer Curves up to forty-five minutes prior to the Operating Hour. The last Offer Curve submitted as of thirty minutes prior to the Operating Hour shall become final and shall be utilized by the Transmission Provider in determining the dispatch of Energy Imbalance Service Resources and in the calculation of Locational Imbalance Prices for the applicable Operating Hour.

(d) Market Participants may submit new or revised Ancillary Service Plans up to forty-five minutes prior to the Operating Hour

3.2 Hour Ahead Resource Plan and Ancillary Service Plan Evaluation

Prior to the start of the Operating Hour, the Transmission Provider shall supply the results of a Supply Adequacy Analyses for the next Operating Hour utilizing the same methodology described under Section 2.4.2(a). A Market Participant with an Energy Obligation Deficiency or Energy Obligation Excess in any hour during the Operating Day shall correct the deficiency or excess and resubmit revised plans and/or schedules to the Transmission Provider by forty-five minutes prior to the applicable Operating Hour. Additionally, the Transmission Provider may perform additional Simultaneous Feasibility Analyses, as needed, throughout the Operating Day utilizing the same methodology described under Section 2.4.2(b).

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

4. Real-Time Period Activities

The following procedures and principles shall govern: (1) the dispatch of Resources made available to the Transmission Provider for the provision of Energy Imbalance Service, including provisions for deviations from dispatch instructions; (2) adjustments made during periods when reserves are activated; (3) procedures for coordinating TLR events and market operations; and (4) the calculation of Locational Imbalance Prices during the Real Time Period.

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

4.1 Dispatch Process

(a) Throughout the Operating Day, generally every 5 minutes, the Transmission Provider shall:

(i) Perform a security constrained economic dispatch (SCED) for the SPP Region utilizing an optimization method to determine the least costly means of obtaining energy to serve the next increment of load based upon submitted Offer Curves, Resource operating data submitted as part of the Resource Plan, binding transmission constraints, forecasted SPP Region load and system conditions from the State Estimator; relaxation of operating limits (Violation Relaxation Limit or VRL).

(ii) Communicate to Market Participants dispatch instructions that specify the desired megawatt output of Dispatchable Resources based upon the security constrained economic dispatch solution;

(iii) Communicate to Market Participants dispatch instructions that specify the scheduled megawatt output of Self-Dispatched Resources based upon the sum of the Energy Schedules associated with that Self-Dispatched Resource as approved in accordance with Section 3.1(b);

(iv) Communicate Manual Dispatch Instructions to Market Participants that specify the desired output of Dispatchable Resources and/or Self Dispatched Resources only in Emergency Conditions where such Emergency Conditions can not be resolved through the process described under Section 4.3 of Attachment AE;

(v) Calculate an Adjusted Net Scheduled Interchange for each Control Area in the SPP Region to account for the Dispatchable Resource dispatch instructions, including any Manual Dispatch Instructions, reserve sharing schedules, and inadvertent interchange payback schedules and communicate this Adjusted Net Scheduled Interchange to the Control Areas for implementation.

Procedures for communication of dispatch instructions shall be specified in the Market Protocols.

(b) In performing the security constrained economic dispatch under Section 4.1, the Transmission Provider shall ensure that the energy dispatch of Dispatchable Resources does not conflict with any specified provision of Schedule 3, Schedule 5 and Schedule 6 Service associated with said Dispatchable Resources. To accomplish this, the Transmission Provider shall limit the dispatchable energy range of Dispatchable Resources to between the Resource's Economic Minimum Limit and Economic Maximum Limit. Details of the Dispatchable Resource dispatchable energy range adjustment shall be specified in the Market Protocols.

(c) The Transmission Provider shall limit the dispatch instructions to External Resources so that i.) the total dispatch instructions of External Resources does not exceed the SPP Contingency Reserve Requirement for the Operating Day and ii.) the total dispatch instructions of External Resources sinking in an individual SPP Market Balancing Authority Area does not exceed the capacity of the largest Resource within that Balancing Authority Area.

(d) An acceptable operating tolerance will be defined for Dispatchable and Self-Dispatched Resources and Non-Dispatchable Resources. A Resource shall be considered as following a dispatch instruction in a Dispatch Interval if the actual output of that Resource is within the acceptable operating range. Resources whose actual output falls outside this operating tolerance shall be considered as failing to follow a dispatch instruction. A Resource's acceptable operating range shall be defined by a high and low tolerance level calculated as follows subject to a minimum range of 5 megawatts above or 5 megawatts below the expected output level and a maximum acceptable operating range of 25 megawatts above or 25 megawatts below the expected output level:

RHi = Max(5 , Min ((MaxMWi * DBP) , 25)) + REGUP

RLi = Max (5, Min ((MaxMWi * DBP) , 25)) + REGDN

Where:

RH = Resource high operating tolerance or over generation limit (megawatt)

RL = Resource low operating tolerance or under generation limit (megawatt)

MaxMW = Maximum Capacity Operating Limit - Resource physical maximum sustainable output for each Operating Hour from Resource Plan.

DBP = Dead band percentage for all Resources is initially set to 10 %,

REGUP = Regulation up service being maintained on the Resource as indicated in the Ancillary Service Plan (MW) for the Operating Hour.

REGDN = Regulation down service being maintained on the Resource as indicated in the Ancillary Service Plan (MW) for the Operating Hour.

i = Dispatch Interval within Operating Hour.

Resources providing Schedule 5 and Schedule 6 services shall be considered following dispatch instructions during any Dispatch Interval in which these Services have been deployed.

(e) To the extent that a Resource is determined by the Transmission Provider to have failed to follow the Transmission Provider's dispatch instructions, such failure to follow dispatch instruction determination in accordance with the procedures set forth under Section 4.1(d) of this Attachment AE, the Market Participant owner of that Resource shall be subject to an Uninstructed Deviation Charge. Resources shall not be subject to Uninstructed Deviation Charges for any Uninstructed Deviation Megawatts caused by: (1) Manual Dispatch Instructions; (2) redeployment by the Balancing Authority; (3) instances when a Resource trips or is derated after receiving dispatch instructions from the Transmission Provider; (4) Non-Dispatchable Resources during uncongested intervals; or (5) the dispatch instructions issued to a Resource were beyond the reported capabilities in the Resource Plan due to the application of a VRL.

In order to receive an Uninstructed Deviation Charge exemption for a Resource under (3) above, the Market Participant must immediately report the change in its Resource Plan, in accordance with Section 1.2.7 (c) of Attachment AE, specifying the Resource trip or deration and must submit an invoice dispute utilizing the process described under Section 6.3 of Attachment AE prior to Transmission Provider determination of the exemption under the Section 6.3 process.

(f) The Transmission Provider may also waive Uninstructed Deviation Charges to the extent a Market Participant can demonstrate such deviation was caused solely by events or conditions beyond its control, and without the fault or negligence of the Market Participant. The Market Participant must provide the Transmission Provider with adequate documentation through the invoice dispute process described under Section 6.3 in order for the Market Participant to be eligible to avoid such Uninstructed Deviation Charges. The Transmission Provider shall determine through the Section 6.3 dispute process whether such Uninstructed Deviation Charges should be waived.

(g) Uninstructed Deviation Charges shall be calculated by the Transmission Provider in accordance with Section 5.5 of this Attachment AE.

(h) In the event of a system failure related to the SPP EIS Market systems or Market Participant systems providing data to SPP that impact Transmission Provider's ability to calculate dispatch instructions for a Resource or Resources, the Transmission Provider will suspend the calculation of dispatch instructions for such Resources and treat them as Self-Dispatched Resources until the calculations of dispatch instructions can be restored.

4.2 Reserve Sharing Schedules

(a) In order to activate the Reserve Sharing System, the Balancing Authority shall notify the Transmission Provider in accordance with Section 6.4.2 of the SPP Criteria. Balancing Authorities must activate the Reserve Sharing System on a non-discriminatory basis for all Resources within their Balancing Authority Area.

(b) The Transmission Provider will activate operating reserves in accordance with the Ancillary Service Plans, SPP Criteria and all applicable reserve sharing agreements. The Transmission Provider shall calculate the interchange schedules for each Balancing Authority Area necessary to implement a reserve sharing activation in accordance with the SPP Criteria. The Transmission Provider shall communicate these interchange schedules to each affected Balancing Authority and such schedules will be used in the calculation of the Balancing Authority Area's Adjusted Net Scheduled Interchange.

(c) Market Participants may submit an Energy Schedule to the Transmission Provider in relation to a reserve sharing activation in one of the following methods:

i. In response to a reserve sharing agreement being activated, Market Participants may enter an Energy Schedule for a specific Resource so that it is dispatched to provide reserve energy for the event.

ii. Prior to real-time, Market Participants may supply a default distribution that will be used by the Transmission Provider to automatically generate Energy Schedules for the Market Participant's Resources such that they will be dispatched according to these schedules in the event of a reserve activation.

iii. Market Participants may override a default distribution by entering an Energy Schedule for a specific Resource.

To the extent that no Energy Schedules are submitted in response to the activation of a reserve sharing agreement, the Transmission Provider shall issue dispatch instructions to Resources scheduled to provide Ancillary Services in accordance with the limits set forth in the Offer Curves and Ancillary Service Plans for such Resources.

(d) Market Participants may revise Energy Schedules submitted in relation to a reserve sharing event after the fact to account for differences between actual operations and the original schedules. Such revisions must be submitted no later than 0100 three days after the Operating Day in which the event occurred. After this time, Energy Schedules are final and shall be used in the calculation of the Market Participant's Imbalance Energy.

(e) The Transmission Provider shall facilitate the settlement and billing for reserve sharing group arrangements in accordance with Attachment AK.

4.3 Coordination of Market Operations under SPP Congestion Management

The Transmission Provider shall use the following process to coordinate the operations of the Energy Imbalance Market during times when a Congestion Management and/or TLR event is declared to manage congestion on one or more flowgates:.

(a) The Transmission Provider shall identify schedules in the NERC IDC that are also included in Market Flows.

(b) The Transmission Provider shall submit the Market Flow impact on each Coordinated Flowgate and Reciprocal Coordinated Flowgate to the NERC IDC. The Market Flow impact on each flowgate shall include the aggregate MW flow impacts on the identified flowgate including the following:

  i. Energy Schedules relating to native load for which no tag has been identified;

  ii. Energy Schedules entirely within a Balancing Authority Area for which a tag has been identified and where the source is either a Dispatchable Resource or Self-Dispatched Resource; and

  iii. Energy Schedules between Balancing Authority Areas for which a tag has been identified where the source is a Dispatchable Resource or Load Settlement Location and the sink is a Load Settlement Location.

  iv. Unscheduled output from Non-Dispatchable Resources.

(c) The Transmission Provider shall assign curtailment priorities to the Energy Schedules causing Market Flow on each flowgate using the identified tags, or for an Energy Schedule associated with native load using an assumed Network Service tag, and in the following priority categories:

  i. Curtailment priorities for flowgates that have not been defined as a Coordinated Flowgate or a Reciprocal Coordinated Flowgate shall be assigned in accordance with NERC TLR procedures.

  ii. For Coordinated Flowgates, the Transmission Provider will assign Market Flow in the Firm priority up to the Firm limit with any excess Market Flow assigned as Non-Firm Network.

  iii. For Reciprocal Coordinated Flowgates, the Transmission Provider will divide its Market Flows into Firm, Non-Firm Network, and Non-Firm

Hourly curtailment priorities. The Transmission Provider will first assign Market Flow in the Firm priority up to the Firm limit, then assign remaining Market Flow in the Non-firm Network priority up to the Non-firm Network limit, and finally assign any excess Market Flow as Non-firm Hourly.

(d) The Market Flow contribution associated with Energy Imbalance Service shall be determined by the Transmission Provider by subtracting the Market Flow associated with the Energy Schedules defined in Section 4.3(b) within that priority level defined in Section 4.3(c) from the total calculated Market Flow for that priority. For Coordinated Flowgates, any Market Flow contribution of Energy Imbalance Service in excess of that assigned to the Firm priority shall be assigned a Non-Firm Priority. For Reciprocal Coordinated Flowgates, any Market Flow contribution of the Energy Imbalance Service in excess of amounts assigned to Firm or Non-Firm Network priorities shall be assigned a Non-Firm Hourly priority.

(e) When congestion occurs on a flowgate that requires a TLR event, the NERC IDC will prescribe curtailments for tags of all Physical Schedules and identify the amount of relief required from Market Flows on the Coordinated Flowgate or Reciprocal Coordinated Flowgate.

(f) The Transmission Provider shall achieve the required reduction in Market Flows provided by the NERC IDC using its security constrained dispatch software and curtailment/adjustment tool ("CAT"), which curtails schedules identified in Sections 4.3(c) and 4.3(d) in the following order until the desired reduction in Market Flows is achieved:

i. To the extent that Market Flows are contributing to the constrained condition, the Transmission Provider shall restrict the ability of the market operating system from contributing further to the constrained condition by binding the Coordinated Flowgate or Reciprocal Coordinated Flowgate constraint. The security constrained dispatch of Dispatchable Resources shall continue within each priority level until the Market Flows within that priority level have been reduced to zero or the flowgate constraint is eliminated, whichever comes first. Any impact on Locational Imbalance Prices will be calculated per Section 4.4 of Attachment AE.

ii. Simultaneously with the security constrained dispatch of Dispatchable Resources that contribute to Market Flows, the CAT shall determine if sufficient Energy Imbalance Service exists to achieve the desired Market Flow relief. If there is an insufficient amount of Energy Imbalance Service to achieve the desired Market Flow relief, CAT shall curtail the remaining schedules identified in Section 4.3(c) impacting the Coordinated Flowgate or Reciprocal Coordinated Flowgate, using their assigned priority level, starting from lowest priority to highest, until the desired Market Flow reduction is achieved or until all such schedules in that priority have been reduced to zero. During this curtailment process, CAT also adjusts the Scheduled Generation of Resources, to the extent that such Resources need to be dispatched below their scheduled amount to achieve the desire Market Flow relief, and such adjusted Scheduled Generation shall be used for settlement purposes. The impact of schedule curtailments on Locational Imbalance Prices will be realized as soon as the changes to Self-Dispatched Resource schedules resulting from the curtailments are reflected within the EIS Market dispatch software and Locational Imbalance Prices shall continue to be calculated in accordance with Section 4.4.

(g) The Transmission Provider shall notify each Market Participant of the aggregate curtailments it is required to make, and such notification shall include Resource name, original schedule, and the generation shift factor associated with their Resources for the constrained flowgates.

(h) The Transmission Provider shall notify each Market Participant if a curtailment is expected to continue into the next Operating Hour. Market Participants may revise their Energy Schedules or operating schedule for Self-Dispatched Resources for the next Operating Hour so long as they maintain the required reduction level in Market Flows required.

(i) Non-Dispatchable Resources shall be instructed to curtail via an XML notification. Such notification shall include the resource name, time period of curtailment, and the curtailment level. When instructed, a Non-Dispatchable Resource shall operate at the lower of its (1) curtailment level or (2) actual net output. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utilities, its output shall be curtailed proportionately, equivalent to Firm Service. The curtailment level of a Non-Dispatchable Resource shall be the sum of the curtailed unscheduled and scheduled portion of the output of Resource as determined by CAT.

4.4 Calculation of Locational Imbalance Prices

A Locational Imbalance Price shall be calculated for each Meter Settlement Location and shall be calculated as the market clearing price at that location based on the security constrained economic dispatch, the Dispatchable Resource Offer Curve prices and resource characteristics submitted by Market Participants and data from the State Estimator. The following rules will be used in calculating the Locational Imbalance Prices:

(a) Locational Imbalance Prices are calculated by the Transmission Provider for each Dispatch Interval as part of the security constrained dispatch solution described under Section 4.1. In performing these calculations, Dispatchable Resources will be eligible to set the Locational Imbalance Price under the following conditions:

  i. The Dispatchable Resource must be operating below its maximum capacity limit, such limit as adjusted in accordance with Section 4.1(b);

  ii The Dispatchable Resource must be operating above its minimum capacity limit, such limit as adjusted in accordance with Section 4.1(b); and

  iii The Dispatchable Resource output must not be ramp rate constrained such that the Dispatchable Resource cannot achieve the optimal desired dispatch point under the economic dispatch.

  Self-Dispatched Resources are not eligible to set the Locational Imbalance Price.

(b) The Transmission Provider shall calculate Locational Imbalance Prices for use in settlement as follows:

  (i) A Locational Imbalance Price shall be calculated for each Meter Settlement Location for every Dispatch Interval.

  (ii) The Locational Imbalance Price for a load Settlement Location for a Dispatch Interval within the Operating Hour shall be equal to the load weighted average of Locational Imbalance Prices calculated for Meter Settlement Locations aggregated to that Settlement Location for that Dispatch Interval. The load weights utilized in this calculation shall be based upon the actual real-time load calculated at each Meter Settlement Location by the State Estimator in that Dispatch Interval. For Resources, the Locational Imbalance Price for a Resource Settlement Location for a

Dispatch Interval shall equal the Locational Imbalance Price calculated for the Meter Settlement Location for the Resource.

(iii) The Locational Imbalance Price at a Settlement Location and a Meter Settlement Location for an Operating Hour shall be equal to the arithmetic average of the Locational Imbalance Prices calculated for each Dispatch Interval at that Settlement Location or Meter Settlement Location within that Operating Hour. No later than fifteen minutes following each Operating Hour, the Transmission Provider shall post the Locational Imbalance Prices for each Settlement Location and Meter Settlement Location for that Operating Hour on its website and shall indicate in that posting which Meter Settlement Locations were utilized in the calculation of Locational Imbalance Prices for each aggregated load Settlement Location.

(c) When SPP issues a reliability directive to any on-line Resource to resolve an Emergency Condition (referred to in the system as "OOME" or out of merit energy) and for the duration of the reliability directive, SPP will determine the appropriate credit for the OOME dispatch as follows:

(i) Each Resource with an OOME instruction that results in an increase in Resource output that creates a sale or an increase in a sale to the EIS Market will be paid, for its additional output attributable to its response to the OOME dispatch instruction, at the higher of the LIP determined by the security constrained economic dispatch for the Resource Settlement Location or the Resource offer curve price at the OOME dispatch point ("OOME Sale Compensation"). If such offer price exceeds the LIP, the difference between the two prices will be multiplied by the minimum of the OOME dispatch instruction and actual output minus the Resource schedule quantity in order to calculate the credit that is recoverable through the revenue neutrality uplift process (Section 5.6 of this Attachment AE). The OOME Sale Compensation shall be limited to the amount necessary to compensate the resource for any under-recovery resulting from its response to the OOME dispatch instruction.

(ii) Each Resource with an OOME instruction that results in a decrease in Resource output that creates a purchase or an increase in a purchase from the EIS Market will pay, for its EIS Market purchase attributable to its response to the OOME Dispatch Instruction, at the lower of the LIP determined by the security constrained economic dispatch for the Resource at the Settlement Location or the Resource offer curve price at the OOME dispatch point ("OOME Purchase Compensation"). If the LIP exceeds such offer price, the difference between the two prices will be multiplied by the Resource scheduled quantity minus the maximum of the OOME Dispatch Instruction and the actual output in order to calculate the credit that is recoverable through the revenue neutrality uplift process (Section 5.6 of this Attachment AE). The OOME Purchase Compensation shall be limited to the amount necessary to compensate the resource for any under-recovery resulting from its response to the OOME dispatch instruction.

(iii) Settlement calculations for any partial hour OOME instruction will be scaled by the number of intervals so that each 5-minute Dispatch Interval is settled for 1/12th of the value indicated by the appropriate price.

(d) In the event that a failure of SPP's EIS Market systems results in a loss of data required for calculation of Locational Imbalance Prices, Imbalance Energy will continue to be settled financially under this Tariff based upon estimated Locational Imbalance Prices. The Transmission Provider shall notify Market Participants if Imbalance Energy is to be settled using estimated prices. The estimated Locational Imbalance Prices shall be calculated as follows.

(i) If Locational Imbalance Pricing data is missing for two hours or less, the most recently calculated Locational Imbalance Prices for each affected Settlement Location shall be utilized for settlement purposes for each of the hours in which Locational Imbalance Pricing data is missing.

(ii) If more than two hours of Locational Imbalance Pricing data is missing, the Locational Imbalance Prices for each hour for which data is missing shall be calculated on a Zone basis based upon the cost associated with the provision of Schedule 4 Service. The cost associated with provision of Schedule 4 Service shall be computed as the greater of (1) actual cost of the highest-cost MWh of energy procured for the purposes of providing Schedule 4 Service, if such energy was procured; or (2) the fuel cost and other variable costs associated with the production of the highest-cost MWh of energy produced for the purpose of providing Schedule 4 Service, such costs not to include opportunity costs. SPP must specifically request the Schedule 4 Service cost information from affected Zone suppliers and the affected Zone suppliers must provide the requested cost information to SPP no later than 24 hours after the request is made.

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4.5 Locational Imbalance Price Corrections

If Locational Imbalance Price corrections are required due to software errors and/or data input errors, the Transmission Provider shall impose corrective measures and take immediate action to remedy such errors in accordance with the following and shall recalculate Locational Imbalance Prices in accordance with the following procedures.

(a) Notice to Market Participants and the public

In any Operating Hour for which the Transmission Provider reasonably believes that a software error or data input error will require correction of one or more Locational Imbalance Prices, the Transmission Provider shall post on its OASIS and website as soon as reasonably practicable a notice that a price correction may be required for that Operating Hour. When the Transmission Provider is aware in advance that a price correction will be required for an Operating Hour, the Transmission Provider shall post a notice of a proposed correction, and if possible a description of the proposed action, prior to the deadline for Resource Plan and Offer Curve submittal for such Operating Hour. If the circumstances do not permit advance notice, the Transmission Provider shall post a notice no later than 5:00 p.m. on the fourth (4^{th}) Calendar Day following the day in which the hour occurs for which Locational Imbalance Prices would be affected by the contemplated price correction.

Prior to making a price correction, if reasonably possible, SPP must post on its OASIS and website a description of its proposed price correction. In any event, the Transmission Provider must post a description of the proposed price correction within five Calendar Days after the date on which a notice of a price correction is posted. If a description of the proposed price correction is not posted within such period, the notice of proposed price correction shall be deemed to be withdrawn. If the Transmission Provider determines that a price correction is not necessary, it shall withdraw the notice of possible price correction from its OASIS and website as soon as reasonably practicable.

(b) Price Corrections Identified After the End of the Notice Period

If the Transmission Provider identifies software or data input errors requiring a price correction, but does not (a) post a notice of price correction or (b) post a description of the proposed price correction within the required time periods, the Transmission Provider shall request Commission approval prior to making the necessary price correction.

(c) Process for Recalculating Prices

The Transmission Provider shall recalculate Locational Imbalance Prices in a manner that reflects, as closely as reasonably practicable, the Locational Imbalance Prices that would have resulted but for the software or data input error, and such recalculated Locational Imbalance Prices shall serve as the basis for settlement.

(d) Market Participant Compensation

If recalculated Locational Imbalance Prices result in Locational Imbalance Prices for Dispatchable Resources that are less than that Market Participant's Offer Curve price for those Dispatchable Resources and Imbalance, the Transmission Provider shall calculate an affected Market Participant's Recalculated LIP Credit for each affected Dispatchable Resource with negative Imbalance Energy as follows:

Recalculated LIP Credit = Resource Imbalance Energy * (Offer Curve price – recalculated Locational Imbalance Price)

If recalculated Locational Imbalance Prices result in Locational Imbalance Prices for Dispatchable Resources that are greater than that Market Participant's Offer Curve price for those Dispatchable Resources and the actual output of such Dispatchable Resources is less than it otherwise would have been absent the price correction, the Transmission Provider shall calculate an affected Market Participant's Recalculated LIP Credit as follows:

Recalculated LIP Credit = maximum of [(Adjusted Dispatch – actual output), 0] * (Offer Curve price – recalculated Locational Imbalance Price), where the Adjusted Dispatch equals the lesser of the Dispatchable Resource's Scheduled

Generation or its projected output level at the recalculated Locational Imbalance Price.

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4.6 Violation Relaxation Limit Values

(a) When necessary to avoid excursions in shadow prices and to ensure a programmatic solution in all cases, the deployment program employs Violation Relaxation Limits ("VRL"). A higher VRL value is an indication of the relative priority for enforcing the constraint type.

For example, the VRL value assigned to a ramp rate limit exceeds that assigned to a flowgate limit indicating that the flowgate constraint should be relaxed before the ramp rate constraint. If the VRL with the lowest value will not allow SPD to balance the market's energy obligations, a higher VRL will be applied. In the case of the Operating Constraint VRL, the VRL value limits the cost of the dispatch needed to balance system injections and withdrawals by capping the shadow price.

There are four categories of VRLs that may be applied within the deployment: 1) Operational Constraints ("OCs"); subcategories being: (a) Flowgate constraints, (b) RTCA constraints, (c) Watch list constraints, (d) Manual constraints and (e) Pnode constraints, (2) Resource ramp rate limits, (3) Market balance (generation to load) and (4) Resource capacity maximum/minimum output limits.

(b) Each year by November 1, VRLs and their associated values shall be reviewed and approved by the SPP Membership Committee. Any changes to the VRLs or associated values must be approved by the Commission prior to their implementation. The most recent FERC approved VRLs and their associated values are set out in Addendum 1 to this Attachment AE.

(c) If a TLR/CAT event is called, SPP will use the VRL values, in Addendum 1 to this Attachment AE, to achieve a market solution. SPP will, consistent with the Commission's directions in Order No. 693, restore the system to respect proven reliability limits as soon as possible, but in no case longer than 30 minutes, through market flow relief or emergency actions and/or issuing manual instructions. If SPP is unable to achieve the relief required by the IDC, solely using market flow relief, SPP will initiate within one business day after this occurrence the analysis described above.

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

5. EIS Settlement Activities

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

5.1 Calculation of EIS Market Settlement Quantities

The Transmission Provider shall calculate each Market Participant's Imbalance Energy megawatt per hour amounts for each hour at each Settlement Location as follows. The settlement interval for Imbalance Energy shall be an Operating Hour.

(a) The sum of the Reported Load within a Settlement Area must equal the Settlement Area Net Load. To the extent that the Transmission Provider observes that a difference exists, the Transmission Provider shall adjust each Market Participant's Reported Load within the Settlement Area such that the sum of Reported Load within the Settlement Area is equal to the Settlement Area Net Load. The adjustments to Reported Load within the Settlement Area shall be performed by the Transmission Provider utilizing profiled data and interval meter data load weighted allocation factors as described in the Market Protocols. The load weighted allocation factors within a Settlement Area associated with profiled data and interval meter data shall be calculated based upon an 80% weighting factor for profiled data and a 20% weighting factor for interval metered data. The load weighted allocation factors shall be calculated as follows:

(i) The profiled data allocation factor (PDAF) for the Settlement Area shall be:

PDAF = (.80 x total profiled load in Settlement Area) divided by;

((.80 x total profiled load in Settlement Area) + (.20 x total interval load in Settlement Area)); and

(ii) The interval data allocation factor (IDAF) for the Settlement Area shall be equal to (1 – PDAF);

(b) A Market Participant's Imbalance Energy for each Resource at each Settlement Location shall be equal to the difference between that Market Participant's actual net generation for that Resource at that Settlement Location and that Market Participant's Scheduled Generation for that Resource at that Settlement Location.

(c) A Market Participant's Imbalance Energy for each load at each Settlement Location shall be equal to the difference between that Market Participant's Reported Load at that Settlement Location and that Market Participant's Scheduled Load at that Settlement Location.

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5.2 Energy Imbalance Service Charges/Credits

The Transmission Provider shall calculate each Market Participant's Energy Imbalance Service Charge/Credit for each hour at each Settlement Location as follows.

(a) A Market Participant's Energy Imbalance Service Charge/Credit at each Settlement Location shall be equal to that Market Participant's Imbalance Energy at that Settlement Location multiplied by the Locational Imbalance Price for that Settlement Location.

(b) A Market Participant's Net Energy Imbalance Service Charge/Credit shall be equal to the sum of that Market Participant's Settlement Location specific Energy Imbalance Service Charges/Credits.

5.3 Under-Scheduling Charges

During any hour, if Locational Imbalance Prices diverge and a Market Participant's load Imbalance Energy is more than 4% (but at least 2 MW) of Reported Load at an applicable Settlement Location in that hour, that Market Participant may be subject to an Under-Scheduling Charge. If the Reported Load is greater than the Scheduled Load by more than 4% of Reported Load (but at least 2 MW) at any Settlement Location, Under-Scheduling Charges will be determined as follows:

(a) For Resource Settlement Locations, the Transmission Provider shall sort the Market Participant's negative Imbalance Energy amounts in ascending order according to each Resource's Locational Imbalance Price, with a secondary sort in ascending alphanumeric order of the Resource name for any Resources that have the same Locational Imbalance Price.

(b) For Load Settlement Locations at which Scheduled Load is less than 96% of Reported Load and the imbalance is at least 2 MW, the Transmission Provider shall sort the Market Participant's positive Imbalance Energy amounts in ascending order according to each load's Locational Imbalance Price.

(c) Utilizing the sorted lists developed under Sections 5.3(a) and 5.3(b) above, and starting with the Resource with the lowest Locational Imbalance Price, the Transmission Provider shall match each Resource's Imbalance Energy against that Market Participant's load Imbalance Energy, starting with the load Imbalance Energy with the lowest associated Locational Imbalance Price, until all of the load Imbalance Energy has been accounted for or until no additional Resources remain.

(d) The following calculation is performed only for Resources that have a Locational Imbalance Price greater than the Locational Imbalance Price for the associated load Settlement Location. A Market Participant's Under-Scheduling Charge, for each Resource identified under Section 5.3(c) as being required to match that Market Participant's Load Imbalance Energy, shall be calculated as follows:

Resource Under-Scheduling Charge = (LLIP – RLIP) * Resource Imbalance Energy, where

RLIP = Locational Imbalance Price of the Resource Settlement Location,

LLIP = Locational Imbalance Price of the associated Load Settlement Location,

Resource Imbalance Energy = the amount of that Resource's Imbalance Energy required to offset the Market Participant's load Imbalance Energy as calculated under Section 5.3(c).

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5.4 Over-Scheduling Charges

During any hour, if Locational Imbalance Prices diverge and a Market Participant's load Imbalance Energy is more than 4% (but at least 2 MW) of Reported Load at an applicable Settlement Location in that hour, that Market Participant may be subject to an Over-Scheduling Charge. If the Scheduled Load is greater than the Reported Load by more than 4% of Reported Load (but at least 2 MW), Over-Scheduling Charges will be determined as follows.

(a) For Resource Settlement Locations, the Transmission Provider shall sort the Market Participant's positive Imbalance Energy amounts in descending order according to each Resource's Locational Imbalance Price, with a secondary sort in ascending alphanumeric order of the Resource name for any Resources that have the same Locational Imbalance Price.

(b) For Load Settlement Locations at which Scheduled Load is greater than 104% of Reported Load and the absolute value of the imbalance is at least 2 MW, the Transmission Provider shall sort the Market Participant's negative Imbalance Energy amounts in descending order according to each load's Locational Imbalance Price.

(c) Utilizing the sorted lists developed under Sections 5.4(a) and 5.4(b), and starting with the Resource with the highest Locational Imbalance Price, the Transmission Provider shall match each Resource's Imbalance Energy against that Market Participant's load Imbalance Energy, starting with the load Imbalance Energy with the highest associated Locational Imbalance Price, until all of the load Imbalance Energy has been accounted for or until no additional Resources remain.

(d) The following calculation is performed only for Resources that have a Locational Imbalance Price less than the Locational Imbalance Price for the associated load Settlement Location. A Market Participant's Over-Scheduling Charge, for each Resource identified under Section 5.4(c) as being required to match that Market Participant's load Imbalance Energy, shall be calculated as follows:

Resource Over-Scheduling Charge = (LLIP-RLIP) * Resource Imbalance Energy, where

RLIP = Locational Imbalance Price of the Resource Settlement Location,

LLIP = Locational Imbalance Price of the associated Load Settlement Location,

Resource Imbalance Energy = the amount of that Resource's Imbalance Energy required to offset the Market Participant's load Imbalance Energy as calculated under Section 5.4(c).

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5.5 Uninstructed Deviation Charges

The Transmission Provider shall calculate Uninstructed Deviation Charges for each hour in which a Resource has been determined to have failed to follow the Transmission Provider's dispatch instructions. For all Resources, whether a Dispatchable Resource, a Self-Dispatched Resource, or a Non-Dispatchable Resource (during congested intervals) that failed to follow dispatch instructions in accordance with the procedures set forth under Section 4.1(d) of this Attachment AE, the Transmission Provider shall calculate an Uninstructed Deviation Charge as follows:

(a) For each Dispatch Interval in an Operating Hour, if a Resource's actual output is greater than (MaxMW + RH), then that Resource's Uninstructed Deviation Megawatt in that Dispatch Interval is equal to the actual output – (MaxMW + RH), where MaxMW and RH are as defined under Section 4.1(d) of this Attachment AE;

(b) For each Dispatch Interval in an Operating Hour, if a Resource's actual output is less than (MaxMW - RL), then that Resource's Uninstructed Deviation Megawatt in that Dispatch Interval is equal to the actual output - (MaxMW - RL), where EOL and RL are as defined under Section 4.1(d) of this Attachment AE;

(c) For each Dispatch Interval in the Operating Hour, if a Resource's actual output is within the acceptable operating range as defined in Section 4.1(d) that Resource's Uninstructed Deviation Megawatt in that Dispatch Interval is equal to zero;

(d) For each Operating Hour, the Transmission Provider shall calculate an Hourly Uninstructed Deviation Megawatt for each Resource that is equal to the average of the absolute value of the Uninstructed Deviation Megawatts calculated for each Dispatch Interval for each Resource in that Operating Hour.

(e) For each Operating Hour and for each Resource, the Transmission Provider shall calculate an Uninstructed Deviation Charge:
Uninstructed Deviation Charge = (Min (Hourly Uninstructed Deviation Megawatt, 25) * 10 % + (Max (0 ,Hourly Uninstructed Deviation Megawatt – 25) * 25 %)) * the absolute value of the Resource Locational Imbalance Price.

(f) The Uninstructed Deviation Change shall be zero for a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility that refused to register its Resource and has been registered by the Transmission Provider as outlined in Section 1.2.2(g) of this Attachment AE.

(g) For each Operating Hour, a Market Participant's Uninstructed Deviation Charge shall be equal to the sum of that Market Participant's Resources' related Uninstructed Deviation Charges.

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5.6 Revenue Neutrality

To the extent that the sum of all charges calculated under Sections 5.2, 5.3, 5.4 5.5 and Section IV.B.2 of Attachment M is not equal to the sum of all credits calculated under Sections 4.5(d), 5.2 and Section IV.B.2 of Attachment M for any hour in the Operating Day, the Transmission Provider shall perform the following calculations for each applicable hour of the Operating Day for each Market Participant such that the total charges are equal to the total credits in each applicable hour.

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

(i) the sum of all Net Energy Imbalance Service Charge/Credits in that hour;

(ii) the sum of all Over Scheduling Charges in that hour;

(iii) the sum of all Under Scheduling Charges in that hour;

(iv) the sum of all Uninstructed Deviation Charges in that hour;

(v) the sum of all Recalculated LIP Credits in that hour;

(vi) the sum of all Designated Balancing Authority Loss Charges in that hour, where such Designated Balancing Authority Loss Charges are calculated in accordance with Section IV.B.2 of Attachment M;

(vii) the sum of all Self-Provided Loss Credits in that hour, where such Self-Provided Loss Credits are calculated in accordance with Section IV.B.2 of Attachment M; and

(viii) the sum of all OOME event credits (if any) for the hour that an OOME event occurs and causes a Resource to be dispatched resulting in a situation as described in Section 4.4(c) of this Attachment.

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

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

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

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

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

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

EIUC = SIC * (EISUOMP / sum of EISUOMP), where;

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

SIC = System Imbalance Charge/Credit calculated under Section 5.6(a);

EISUOMP = Market Participant Energy Imbalance Service Uplift Obligation as calculated under Section 5.6(b)

(d) For each hour, each Market Participant's total Energy Imbalance Uplift Charge/Credit shall be equal to the sum of that Market Participant's Settlement Location specific Energy Imbalance Uplift Charge/Credit calculated under Section 5.6 (c).

(e) For one year following the EIS Market Effective Date, the Transmission Provider shall post on its website on a monthly basis, by Operating Hour, the net of all Energy Imbalance Uplift Charges/Credits and each of the following charge types for that hour:

(1) the net of all Net Energy Imbalance Service Charges/Credits;

(2) the sum of all Uninstructed Deviation Charges;

(3) the sum of all Over Scheduling Charges;

(4) the sum of all Under Scheduling Charges;

(5) the sum of all Recalculated LIP Credits; and

(6) by charge type, the net of any other credits or charges not encompassed within (1) through (5).

Information for a month shall be posted no later than the 15th day of the succeeding month and shall be posted in a programmatic interface format.

6. Release of Offer Curve Data

The Transmission Provider will release the hourly Offer Curves for Dispatchable Resources ninety (90) days after the day for which the offer was submitted. Such information released by the Transmission Provider will not include the identity of the Market Participant that submitted the Offer Curve.

Effective Date: 7/26/2010 - Docket #: ER11-120

7. Billing

The Transmission Provider shall prepare a billing statement each billing cycle in accordance with this Section of Attachment AE. Such billing statements shall be prepared for each Market Participant in accordance with the charges and credits specified in Section 5 of this Attachment AE, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the Market Protocols, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Unresolved billing disputes shall be settled in accordance with procedures specified in Section 12 of this Tariff

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

7.1 Settlement Statements

(a) The Transmission Provider shall issue a preliminary settlement statement for an Operating Day no later than 7 Calendar Days following the applicable Operating Day unless the 7th day following the applicable Operating Day is not a Business Day, in which case, the preliminary settlement statement shall be issued on the first Business Day thereafter.

(b) The Transmission Provider shall issue a final settlement statement for an Operating Day no later than 47 Calendar Days following the applicable Operating Day unless the 47th Calendar Day following the applicable Operating Day is not a Business Day, in which case, the final settlement statement shall be issued on the first Business Day thereafter.

(c) The Transmission Provider shall make corrections to the preliminary and final settlement statements for an Operating Day for data errors and settlement statement disputes that have been resolved. Settlement associated with a specific Operating Day shall be considered final at the end of the 365th Calendar Day following the applicable Operating Day.

(d) To the extent that a Market Participant, or its designated meter agent, does not submit meter data representing that Market Participant's actual hourly Resource output and load consumption in accordance with the timelines specified in the Market Protocols, the Transmission Provider shall use estimated data for that Market Participant that is equal to that Market Participant's Scheduled Generation and Scheduled Load for the applicable hours for the purposes of calculating the preliminary statements specified under Sections 7.1(a). To the extent a Meter Agent does not submit data representing the Net Actual Interchange, the Transmission Provider will substitute hourly integrated Adjusted Net Scheduled Interchange. In the event that actual meter data is not submitted prior to the issuance of a final settlement statement, the Transmission Provider shall use the best available data, which may include estimated meter data as developed by the Transmission Provider, for the purposes of calculating final settlement statements.

7.2 Invoices

(a) The Transmission Provider shall issue an invoice detailing all charges and credits specified in Section 5 of this Attachment AE on a weekly basis in accordance with the invoice issue dates specified in the Market Protocols.

(b) The Transmission Provider shall make payments to the Market Participant for any net credit shown on the invoice and the Market Participant shall make payment to the Transmission Provider for any net charge shown or the invoice, including disputed amounts. Resolution of disputed amounts shall be shown as an adjustment on future invoices.

(c) Market Participants shall make payment to the Transmission Provider that is equal to the net charge shown on the invoice by no later than 5:00 pm Central Prevailing Time on the 3rd Business Day following the day the invoice was issued.

(d) The Transmission Provider shall make payment to the Market Participant that is equal to the net credit shown on the invoice by no later than 5:00 pm Central Prevailing Time on the 5th Business Day following the day the invoice was issued subject to the procedures specified under Section V of Attachment L.

(e) All payments to the Market Participant and all payments to the Transmission Provider shall be made by electronic funds transfer in U.S. dollars.

7.3 Invoice Disputes

In the event that a dispute arises between the Market Participant and the Transmission Provider concerning any initial, final or Resettlement settlement statements contained within an invoice that cannot be resolved to the Market Participant's satisfaction, such disputes shall be resolved as follows:

a) In the case of a dispute relating to an initial or final settlement statement, the Market Participant must notify the Transmission Provider within 90 Calendar Days following the issue date of the applicable invoice of the items that the Market Participant wishes to dispute. In the case of Resettlement statements, the Market Participant must notify the Transmission Provider within 30 Calendar Days following the issue date of the applicable invoice of the items contained in that statement that the Market Participant wishes to dispute, which issues must relate to incremental changes in data that occurred between issuance of the final settlement statement and the first Resettlement statement or between Resettlement statements.

The notice of dispute must contain the following minimum information:

- Statement type (initial, final, resettlement 1-11, ad hoc resettlement)
- Charge type
- Estimated dispute amount in dollars
- Operating Day
- Start interval
- End interval
- Statement ID
- Transmission Customer
- Settlement Location
- Long description
- Short description.

(b) If the Transmission Provider determines that additional information is required concerning a submitted notice of dispute, the Transmission Provider shall notify the Market Participant no later than 30 days following the date the notice of dispute was submitted to the Transmission Provider. The Market Participant must then submit additional information to the Transmission Provider within 30 days in order to have the notice of dispute considered valid.

(c) The Transmission Provider shall use its best efforts to notify the Market Participant of approval or denial of the submitted notice of dispute within 20 Business Days following the close of the applicable 90 day or 30 day window specified under subsection 7.3(a) or subsection 7.3(b). If the Transmission Provider estimates that it will take longer than the 20 Business Day window to analyze a specific billing dispute, the Transmission Provider shall notify the Market Participant and provide an estimate of the amount of time required to complete the analysis.

(d) If the Transmission Provider denies a Market Participant's notice of dispute or the Market Participant is not satisfied that it is receiving timely consideration of the dispute, the Market Participant may initiate the dispute resolution procedures specified under Section 12 of this Tariff.

7.4 Interest on Unpaid Balances

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the invoice to the date of payment.

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

7.5 Customer Default

Customer default will be handled in accordance with Attachment X (SPP Credit Policy).

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

8. Confidentiality Provisions

This Section 8 shall apply to Confidential Information disclosed by a Market Participant to SPP or by SPP to a Market Participant or its designee, the Market Monitor, the Commission, or an Authorized Requestor and shall only be applicable to Confidential Information referenced within this Attachment AE, Attachment AF and Attachment AG.

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

8.1 Restrictions on Confidential Information Provided to Receiving Party

SPP or any Market Participant ("Receiving Party") may not Disclose Confidential Information received from the other ("Disclosing Party") to any person, corporation, or any other entity except as specifically permitted in this Section 8 of Attachment AE.

A Market Participant that is subject to a freedom of information or similar statute must, prior to receiving Confidential Information, provide the Transmission Provider a statement identifying and forwarding copies of the particular statute, rule or regulation, protective order, or practice that will allow that Market Participant to keep Confidential Information received by it hereunder confidential and non-public, and of limited distribution within the Market Participant as described above. In the event that such Market Participant receives a request pursuant to the applicable freedom of information or similar statute for information deemed confidential pursuant to this section, the Market Participant shall promptly notify the Disclosing Party of such request.

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

8.1.1 Procedures for Confidential Information

Receiving Party shall adopt procedures within its organization to maintain the confidentiality of all Confidential Information. Such procedures must provide that:

(a) The Confidential Information will be Disclosed to Receiving Party's directors, officers, employees, representatives and agents only on a "need to know" basis;

(b) Receiving Party shall make its directors, officers, employees, representatives and agents aware of Receiving Party's obligations under this Section 8;

(c) Receiving Party shall cause any copies of the Confidential Information that it creates or maintains, whether in hard copy, electronic format, or other form, to identify the Confidential Information as such; and to retain such confidential marking;

(d) Before Disclosing Confidential Information to a representative or agent of Receiving Party, Receiving Party shall require a nondisclosure agreement with each such representative or agent. Such nondisclosure agreement shall contain confidentiality provisions substantially similar to the terms of this Section 8.

Any Receiving Party seeking to dispute the designation of information as confidential may challenge such designation through the SPP dispute resolution process as established in Section 12 of this Tariff, unless the Receiving Party has received Confidential Information in connection with a proceeding at the Commission or in connection with a state regulatory proceeding. Any challenge to the confidentiality of Confidential Information obtained in connection with an administrative or legal proceeding shall be presented for consideration to the appropriate court or tribunal.

8.1.2 Exceptions

Without violating the confidentiality provisions of this Section 8, a Receiving Party may disclose certain Confidential Information:

(a) As required by any law, regulation, or order, or expressly required or permitted by this Tariff, provided that the Receiving Party must make reasonable efforts to restrict public access to the Disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(b) If the Disclosing Party that supplied the Confidential Information to the Receiving Party has given its prior written consent to the Disclosure as set forth in Subsection 8.1.4(c), which consent may be given or withheld in Disclosing Party's sole discretion; or

(c) If, before it is furnished to Receiving Party, the Confidential Information is in the public domain; or

(d) If, after it is furnished to Receiving Party, the Confidential Information enters the public domain other than through a manner inconsistent with the provisions of this Section; or

(e) If reasonably deemed by the Receiving Party to be required to be Disclosed in connection with a dispute between Receiving Party and Disclosing Party; provided that the Receiving Party must make reasonable efforts to restrict public access to the Disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(f) To a vendor or prospective vendor of goods and services to SPP so long as such vendor or prospective vendor: (i) is not a Market Participant and (ii) executes a confidentiality agreement with terms substantially similar to those in this Section 8.

8.1.3 Injunctive Relief and Specific Performance

It may be impossible or very difficult to measure in terms of money the damages that would accrue due to any breach by Receiving Party of this Section 8, or any failure to perform any obligation contained in this Section 8, and, for that reason, among others, a Disclosing Party affected by a Disclosure or threatened Disclosure is entitled to injunctive relief, including specific performance, of this Section 8 (but is not hereby precluded from seeking other forms of relief). In the event that a Disclosing Party institutes any proceeding to enforce any part of this Section 8, the affected Receiving Party, by entering any agreement incorporating this Tariff, now waives any claim or defense that an adequate remedy at law exists for such a breach.

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

8.1.4 Market Participant Access and SPP Use of Confidential Information

(a) No Market Participant shall have a right hereunder to receive or review any documents, data, or other information of another Market Participant, including documents, data, or other information provided to SPP, to the extent such documents, data, or information have been designated as Confidential Information under this Section 8; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based on such Confidential Information if the composite does not, directly or by its nature, disclose any individual Market Participant's confidential data or information.

(b) SPP shall collect and use Confidential Information only in connection with its authority under this Tariff and the retention of such information shall be in accordance with SPP's retention policies. Except as otherwise provided in Sections 8.1.2, 8.1.5, 8.2 and 8.3, SPP shall not disclose to Market Participants or to third parties, any Confidential Information of a Market Participant or a Market Participant Applicant; provided that nothing contained herein shall prohibit SPP from providing Market Participant Confidential Information to NERC or any of its Regional Reliability Councils to the extent that: (i) the SPP determines, in its reasonable discretion, that the exchange of such information is required to enhance and/or maintain reliability within the SPP Region and its neighboring Control Areas; (ii) such receiving entity is bound by a written agreement to maintain such confidentiality; and (iii) the SPP has notified the affected Market Participant of its intention to release such information no less than five (5) Business Days prior to the release.

(c) Nothing contained herein shall prevent SPP from releasing a Market Participant's Confidential Information to a third party provided that the Market Participant has delivered to SPP specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. SPP shall limit the release of a Market Participant's Confidential Information to that specific authorization received from the Market Participant. Nothing herein shall prohibit a Market Participant from withdrawing such authorization upon written notice to the SPP who shall cease such release as soon as practicable after receipt of such withdrawal notice.

(d) Nothing contained herein shall prevent SPP from releasing a Market Participant's Confidential Information to a Transmission Owner for purposes of transmission operations provided that: (i) the SPP determines, in its reasonable discretion, that the exchange of such information is required to enhance and/or maintain reliability within the SPP Region and its neighboring Control Areas; (ii) such receiving entity is bound by a written agreement to maintain such confidentiality; and (iii) the SPP has notified the affected Market Participant of its intention to release such information no less than five (5) Business Days prior to the release.

8.1.5 Required Disclosure

(a) Notwithstanding anything in this Section 8 to the contrary except Section 8.2, Section 8.3 and Section 8.4, if a Receiving Party is required by applicable law, or in the course of administrative or judicial proceedings, other than Commission or state regulatory proceedings or investigations, to Disclose to third parties, other than to the Commission or its staff, Confidential Information that is otherwise required to be maintained in confidence pursuant to this Tariff, the Receiving Party subject to such Disclosure requirement may Disclose such information; provided, however, that the Receiving Party shall not release the data until the affected Disclosing Party(ies) provide written consent or until the affected Disclosing Party's(ies') legal avenues to prevent the disclosure are exhausted.

As soon as the Receiving Party learns of the Disclosure requirement and prior to making Disclosure, it shall notify the affected Disclosing Party(ies) of the requirement and the terms thereof and the date on which it may be required to Disclose the information. The affected Disclosing Party(ies) may direct, at their sole discretion and cost, any challenge to or defense against the Disclosure requirement. The Receiving Party shall cooperate with such affected Disclosing Party(ies) to the maximum extent practicable to minimize the Disclosure of the Confidential Information consistent with applicable law. To the extent reasonably possible, the confidentiality of Confidential Information subject to this Section 8.1.5 will be maintained with (a) a protective order, (b) other procedures available for protecting confidential data or (c) by aggregating data to prevent Disclosure of Confidential Information.

Each Receiving Party shall cooperate with the affected Disclosing Party(ies) to obtain proprietary or confidential treatment of such Confidential Information by the person to whom such information is Disclosed prior to any such Disclosure.

(b) Section 8.1.5(a) does not apply to Disclosure of information to the Commission or its staff or to a state regulator or its staff.

8.1.6 Limitations

Nothing contained in Section 8.1 through and including 8.1.5 shall require any Receiving Party to violate any law or file a lawsuit in order to prevent disclosure of Confidential Information.

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8.2 Confidentiality Provisions Applicable to the Market Monitor Reporting to the Board of Directors

For the purposes of this Section 8.2, references to Market Monitor shall mean the Market Monitor as defined under Section 3.1 of Attachment AG.

(a) Notwithstanding anything in this Section 8 to the contrary, in order to enable the Market Monitor to discharge its duties, SPP is authorized to provide Market Participant Confidential Information and any other information, data or materials that constitutes Confidential Information under this Tariff to the Market Monitor. For purposes of Confidential Information provided by SPP to the Market Monitor, the SPP will be considered to be a Disclosing Party, and for purposes of this Section 8.2, the Market Monitor will treat both the SPP and, if known to the Market Monitor, the Market Participant originally providing specific Confidential Information as Disclosing Parties in the event the Market Monitor receives a request for Confidential Information under this Section 8.2.

(b) The Market Monitor shall use all reasonable procedures necessary to protect and preserve the confidentiality of all Confidential Information as defined in Section 8.1 received by it in connection with the discharge of its duties.

(c) Except as may be required by subpoena or other compulsory process or as set forth in Sections 8.4(a) and 8.4(b), the Market Monitor shall not Disclose Confidential Information to any person or entity except to the Commission or its staff or without prior written consent. Upon receipt of a subpoena or other compulsory process for the Disclosure of Confidential Information, the Market Monitor shall promptly notify the affected Disclosing Party(ies) that originally provided the data and shall provide all reasonable assistance requested by the affected Disclosing Party(ies) to prevent Disclosure, and if possible under the terms of the subpoena or other compulsory process shall not release the data until the affected Disclosing Party(ies) provide written consent or until the affected Disclosing Party(ies') legal avenues to prevent disclosure are exhausted. To the extent reasonably possible, the confidentiality of a Confidential Information subject to this Subsection 8.2(b) will be maintained with (i) a protective order, (ii) other procedures available or protecting confidential data or (iii) by aggregating data to prevent Disclosure of Confidential Information.

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8.3 Disclosure to Commission

(a) Notwithstanding any provisions of this Section 8 to the contrary, if the Commission or its staff, during the course of an investigation or otherwise, requests Confidential Information from SPP and/or the Market Monitor that is otherwise required to be maintained in confidence pursuant to this Tariff, SPP and/or the Market Monitor, as applicable shall provide the requested information to the Commission or its staff, within the time provided for in the request for information. Should the SPP and/or the Market Monitor require additional time to provide the information requested due to logistical matters such as the volume of information requested or technical complexity involved, SPP and/or the Market Monitor will promptly communicate that need to the individual requesting the information and they shall establish the time for production of the requested information.

(b) In providing the information to the Commission or its staff, SPP and the Market Monitor shall, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, request that the Confidential Information be treated as confidential and non-public by the Commission and its staff and that the Confidential Information be withheld from public disclosure. SPP and/or the Market Monitor shall promptly notify the affected Disclosing Party(ies) that originally submitted the requested Confidential Information when it receives from the Commission or its staff a request for Disclosure of Confidential Information.

8.4 Disclosure to Authorized Agencies

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

8.4.1 Basic Requirements for Disclosure

For the purposes of this Section 8.4 Authorized Agency is a state regulatory commission which is authorized (or will be authorized upon satisfaction of the requirements herein) to receive confidential information pursuant to this section. The term Authorized Agency also includes state commissions acting jointly either through a regional state committee or otherwise. An Authorized Requestor is a representative of an Authorized Agency.

The Transmission Provider and/or Market Monitor shall only disclose Confidential Information, otherwise required to be maintained in confidence pursuant to Attachment AE of this Tariff, to an Authorized Requestor solely under the following conditions:

(a) The Authorized Requestor has executed a non-disclosure agreement with the Transmission Provider, stating:

i. the position he or she holds within or the relationship he or she has with the Authorized Agency for which he or she will be an Authorized Requestor;

ii. that he or she is authorized to enter into and perform the obligations of the non-disclosure agreement;

iii. that the relevant Authorized Agency has practices or procedures adequate to protect against the unauthorized release of any Confidential Information received pursuant to the non-disclosure agreement;

iv. that he or she is familiar with, and will comply with, any applicable practices or procedures of the Authorized Agency which the Authorized Requestor represents; and

v. that he or she is not in breach of any non-disclosure agreement entered into with the Transmission Provider.

(b) The Transmission Provider is able to verify that the Authorized Agency employing or retaining the Authorized Requestor has provided the Transmission Provider with the following information pursuant to Section 2.2 of Attachment AL (Form of Non-Disclosure Agreement for Authorized Requestors) to this Tariff:

i. a list of authority (including statutory) specifying the particular Authorized Agency's duty, responsibility or authority in fulfillment of which it will make requests to the Transmission Provider or the Market Monitor under this Section for information, including, but not limited to, that enumerated and described as available to the Market Monitor in Attachment AG of this Tariff; or, in the case of regional state committee, an order of the Commission prohibiting the release of Confidential Information by the regional state committee, except in accordance with the terms of the non-disclosure agreement;

ii. a statement notifying and identifying to the Transmission Provider that the Authorized Agency has practices or procedures in place adequate to protect against the unauthorized release of Confidential Information; and

iii. confirmation in writing that the Authorized Requestor is authorized by the Authorized Agency to enter into the non-disclosure agreement and to receive Confidential Information under Attachment AE to this Tariff.

(c) The Authorized Agency has provided either an order or a certification from counsel to such Authorized Agency or some other means acceptable to Transmission Provider , confirming that:

(i) the Authorized Agency has statutory authority (or in the case of regional state committee is in receipt of and bound by a Commission Order referred to in Subsection (b)(i) above) to protect the confidentiality of any Confidential Information received pursuant to the non-disclosure agreement from public release or disclosure and from release or disclosure to any other entity, including other agencies of state government, except to the extent that such disclosure is required or permitted by state law;

(ii) except as provided in Subsection (d) below, the Authorizing Agency will defend against any disclosure of Confidential Information pursuant to any third party request through all available legal process, including, but not limited to, obtaining any necessary protective orders;

(iii) the Authorizing Agency will provide the Transmission Provider with prompt notice of any such third party request or legal proceedings and will consult and cooperate with the Transmission Provider and/or any affected

Market Participant in its efforts to deny the third party request or defend against such legal process;

(iv) in the event a protective order or other remedy is denied, the Authorizing Agency will direct Authorized Requestors authorized by it to furnish only that portion of the Confidential Information that its legal counsel advises the Transmission Provider in writing is legally required to be furnished;

(v) the Authorizing Agency will exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information;

(vi) the Authorizing Agency has adequate practices or procedures in place to protect against the release of such Confidential Information; and

(vii) the Authorizing Agency has authorized the Authorized Requestor to enter into the non-disclosure agreement and to receive Confidential Information pursuant to this Attachment AE to this Tariff and under the non-disclosure agreement, and can provide a written copy of such authorization.

(d) The certification from counsel for the Authorized Agency referred to in Subsection (c)(ii) above must affirmatively disclose any state law that will prohibit or prevent the Authorized Agency from defending against any disclosure of Confidential Information pursuant to any third party request as otherwise required by Subsection (c)(ii). In an instance where there is such a state law disclosed, such certification shall confirm that the Transmission Provider would have notice of the third party request and standing to pursue legal processes, including the obtaining of a protective order, before the forum in which state law prohibits or prevents the Authorized Agency from taking such actions itself.

8.4.2 Schedule of Authorized Requestors

The Transmission Provider shall maintain a schedule of all Authorized Requestors and the Authorized Agencies they represent, which shall be made available on its website or by written request. The schedule shall include phone numbers and e-mail addresses. Such schedule shall be compiled by the Transmission Provider, based on information provided by any Authorized Requestor and/or Authorized Agency. The Transmission Provider shall update the schedule promptly upon receipt of information from an Authorized Requestor or Authorized Agency, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Transmission Provider in the compilation and/or maintenance of the schedule

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8.4.3 Use of Confidential Information

The Authorized Requestor shall use the Confidential Information solely for the purpose of assisting an Authorized Agency in discharging its duty, responsibility or authority in fulfillment of which it authorizes Authorized Requestors to make requests for Confidential Information and for no other purpose. Any and all Authorized Requestors sponsored by the same Authorized Agency may have access to the Confidential Information that is provided to the sponsoring Authorized Agency pursuant to an information request described in Section 8.4.5.

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8.4.4 Limited Oral Disclosures

(a) The Transmission Provider or the Market Monitor may, in the course of discussions with an Authorized Requestor or Authorized Requestors in meetings or teleconferences, orally disclose information otherwise required to be maintained in confidence, without the need for a prior information request. Such oral disclosures shall provide enough information to enable the Authorized Requestors or their Authorized Agency to determine whether additional information requests are appropriate. The Transmission Provider or the Market Monitor will not make any written or electronic disclosures of Confidential Information to the Authorized Requestor pursuant to this section. In any such discussions, the Transmission Provider or the Market Monitor shall ensure that the individual or individuals receiving such Confidential Information are Authorized Requestors, orally designate Confidential Information that is disclosed, and refrain from identifying any specific affected Market Participant whose information is disclosed. The Transmission Provider or Market Monitor shall also be authorized to assist Authorized Requestors in interpreting Confidential Information that is disclosed.

(b) The Transmission Provider or the Market Monitor shall provide any affected Market Participant with oral notice of any oral disclosure promptly, but not later than one (1) business day after the oral disclosure. Such oral notice to the affected Market Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Information of any other entity and must be received by the affected Market Participant before the name of the affected Market Participant is released to the Authorized Requestor; provided, however, the identity of the affected Market Participant must be made available to the Authorized Requestor within two (2) business days of the initial oral disclosure.

8.4.5 Information Requests

(a) Form: Information requests to the Transmission Provider or the Market Monitor shall be in writing, and shall include electronic communications addressed to the Transmission Provider or to the Market Monitor as appropriate.

(b) Content: Each information request shall describe, in as much detail as possible, the particular information sought, including the time period for the requested information; provide a description of the purpose for which the information is being sought and state the time period for which it is expected that the information will need to be retained by the Authorized Requestor.

(c) Notice:

i. The Transmission Provider or the Market Monitor shall provide an affected Market Participant with notice of and a copy of an information request by an Authorized Requestor as soon as possible, but not later than two (2) business days after the receipt of the information request.

ii. The Transmission Provider shall maintain all information requests of a general nature in an electronic form accessible by Market Participants and Authorized Requestors. Such list shall not include those information requests that sought information of or about a named Market Participant or that would, in the Transmission Provider's view, otherwise be readily ascertainable as being directed toward Confidential Information from or about an individual Market Participant. On at least an annual basis the Transmission Provider shall delete from the list all information requests for which the Confidential Information has been returned or destroyed by the Authorized Requestor.

(d) Disclosure: Subject to the provisions of Section 8.4.5(f) and (g) below, the Transmission Provider or the Market Monitor shall supply the information sought to the Authorized Requestor in response to any information request within five (5) business days after the receipt of the information request, or within such longer period as may be specified by the information request, unless a timely objection has been made to the information request, or unless the requested information can only reasonably be made available within an extended time period.

To the extent that the Transmission Provider or the Market Monitor cannot reasonably prepare and deliver the requested information within the five (5) business day period or any longer period specified in the information request, it shall, within such period, hold discussions with the Authorized Requestor and provide the Authorized Requestor with a mutually agreed upon written schedule for the provision of such remaining information. Upon providing the requested information to the Authorized Requestor, the Transmission Provider or the Market Monitor shall provide a copy of the disclosed information to the Affected Participant(s), or provide a listing of the Confidential Information disclosed; provided, however, that the Transmission Provider or the Market Monitor shall not reveal any affected Market Participant's Confidential Information to any other Market Participant.

(e) Objection and Clarification: Notwithstanding Section 8.4.5(d) above, should the Transmission Provider, the Market Monitor or an affected Market Participant object to an information request or any portion thereof, any of them or the Authorized Requestor may, within four (4) business days following the Transmission Provider's or the Market Monitor's receipt of the information request, request, in writing, a conference with the Authorized Agency, or the Authorized Agency's Authorized Requestor, to resolve differences concerning the scope or time period covered by the information request; provided, however, nothing herein shall require the Authorized Agency to participate in any conference.

Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then the Transmission Provider, the affected Market Participant or the Authorized Agency may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any participant refusing or terminating such conference. Any complaints filed at FERC objecting to a particular information request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding.

If no FERC proceeding regarding the information request is commenced within such three-day period, the Transmission Provider or the Market Monitor shall respond to the Information Request within five (5) business days or any longer period that may be specified by the information request, counted from the expiration of such three-day period.

When an information request pertains to a Market Participant, the affected Market Participant may request that clarifying information be included in the response.

(f) Opportunity to Respond to Confidentiality Claims: If the affected Market Participant, the Transmission Provider or the Market Monitor considers the information sought by the information request as Confidential Information, the Authorized Requestor shall be provided an opportunity to challenge the designation or classification of the requested information as Confidential Information.

(g) Response to Tailored Request for Information from State Commissions: Market Monitor may respond to tailored requests for information from state commissions regarding general market trends and the performance of the wholesale market, but not for information designed to aid state enforcement actions. Granting or refusing such requests will be at the Market Monitor's discretion, based on agreements worked out between the Transmission Provider and the states, or otherwise based on time and resource availability.

(h) Limitation On Disclosure Obligation: The Transmission Provider or the Market Monitor shall not be required to make disclosure in response to an information request: (i) in circumstances where an electronic data link, dedicated communication circuit or other hardware or third party services would be necessary to effectuate the disclosure; (ii) that is of a scope or extent materially similar to the flow of data from Market Participants to the Transmission Provider or from the Transmission Provider to the Market Monitor; (iii) that is unduly burdensome; or (iv) that is not pertaining to general market trends or the performance of the Transmission Provider.

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

8.4.6 Limited Discussion of Confidential Information Among Authorized Requestors Sponsored By Different Authorized Agencies

Authorized Requestors who are parties to non-disclosure agreements but who are sponsored by different Authorized Agencies may discuss Confidential Information with each other, provided that:

(a) They have each requested and received from the Transmission Provider or the Market Monitor such Confidential Information;

(b) At least one of such Authorized Requestors notifies the Transmission Provider in advance of the identity of the other Authorized Requestor(s) with whom such Confidential Information will be discussed; and

(c) The Transmission Provider confirms that the Authorized Requestors who will participate in the discussion received the Confidential Information as provided in Subsection (a) above. The Transmission Provider shall respond to a notification under Subsection (b) above within two (2) business days from receipt of the notification.

The Transmission Provider shall provide an affected Market Participant with notice of the planned discussion within two (2) business days from receipt of notification of the planned discussion. Such discussion among Authorized Requestors shall not change the status of the Confidential Information. It shall remain Confidential Information.

8.4.7 Breach of Non-Disclosure Obligations

In the event of any breach of a non-disclosure agreement:

(a) The Authorized Requestors and/or their respective Authorized Agency shall promptly notify the Transmission Provider or the Market Monitor, who shall, in turn, promptly notify any affected Market Participant of any unauthorized release of Confidential Information provided pursuant to any non-disclosure agreement.

Upon notification, the Transmission Provider will cease disclosure to the Authorized Requestor pursuant to any information requests and will make no disclosure pursuant to any information request pending from the Authorized Requestor until it can be determined after consultation with the Authorized Requestor, his or her Authorized Agency and the affected Market Participant that an appropriate combination of the following factors justifies resumption of the Authorized Requestor's access to Confidential Information: (i) the unauthorized disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Requestor; (ii) there was no harm or economic damage suffered by the Affected Participant; (iii) there are now practices or procedures in place adequate to prevent a recurrence of the unauthorized disclosure; and/or (iv) similar good cause shown.

(b) If the Transmission Provider or the Market Monitor receives from an Authorized Requestor or Authorized Agency a written notice that a breach has occurred, or FERC has made a ruling that a breach has occurred, the Transmission Provider and/or, the Market Monitor shall terminate the non-disclosure agreement and require either the immediate return of all Confidential Information obtained by the Authorized Requestor pursuant to the non-disclosure agreement or a certification of its destruction.

The Transmission Provider shall verify the breach in consultation with the Authorized Agency. If it is subsequently determined that there was no breach, or if otherwise justified by circumstances described in Subsection (b) above, the

Transmission Provider shall restore the status of the Authorized Requestor. Any other rights and remedies shall be pursuant to the terms of the non-disclosure agreement.

(c) No Authorized Requestor, who is an employee of an Authorized Agency, shall have responsibility or liability whatsoever under the non-disclosure agreement or Attachment AE to this Tariff for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of Confidential Information to persons not authorized to receive it.

However, nothing in this Section 8.4.7.c is intended to limit the liability of any person who is not an employee of or a member of an Authorized Agency, to the degree not granted limitations as to liability under applicable state law of the Authorized Agency's state, when such a person is under contract to perform services for the Authorized Agency, for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

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

8.5 Preservation of Rights

Notwithstanding any provision in this Section 8, a Disclosing Party shall have the right to pursue all appropriate actions to prevent or contest any attempt to remove the confidential status or any order removing such confidential status of its Confidential Information.

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

8.6 Notice

Notwithstanding any provision in this Section 8 (except as detailed in Section 8.4), the Transmission Provider shall provide at least five business days notice to the Disclosing Party of its intent to provide Confidential Information to any other entity. The Transmission Provider shall not be required to provide such notice if such disclosure is prohibited by law or Order or required by law or Order prior to five business days.

9. Liabilities Relating To Balancing Function Agreement

This Section 9 applies to Balancing Authorities performing the balancing functions listed in the "Agreement Between Southwest Power Pool, Inc and the Southwest Power Pool Balancing Authorities Relating to Implementation of the EIS Market." ("Balancing Function Agreement") Each Balancing Authority which is a signatory to the Balancing Function Agreement will be eligible for the waiver of liabilities as set forth in Section 9.1. A Balancing Authority must be a signatory in order for this Section 9 to be applicable to them. In addition, certain third parties are eligible for the waiver of liability provision as set forth in Section 9.2.

9.1 Limitation of Liability

The Transmission Provider shall not be liable for money damages or other compensation to any Transmission Customer or Users for actions or omissions by the Transmission Provider or Balancing Authority in performing its obligations under the Balancing Function Agreement, except to the extent such act or omission by the Transmission Provider is found to result from its gross negligence or intentional wrongdoing. A Balancing Authority shall not be liable for money damages or other compensation to any Transmission Customer or Users for actions or omissions by such Balancing Authority or Transmission Provider in performing its obligations under the Balancing Function Agreement, except to the extent such act or omission by such Balancing Authority is found to result from its gross negligence or intentional wrongdoing. The Transmission Customer or Users may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of the Transmission Provider or a Balancing Authority or Affiliate of either solely by reason of their status as directors, members, shareholders, officers, employees or agents of the Transmission Provider or a Balancing Authority or Affiliate of either. In no event shall the Transmission Provider or a Balancing Authority be liable to any Transmission Customer for any incidental, consequential, punitive, special, exemplary or indirect damages, loss of revenues or profits, arising out of, or connected in any way with the performance or non-performance under the Balancing Function Agreement.

9.2 Limitations of Liability For Third Parties

The provisions set forth in Section 9.1 also shall apply to entities that take responsive action to implement or comply with the directives or needs of the Transmission Provider or Balancing Authority relating to the performance of this Balancing Function Agreement.

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

Addendum 1 to Attachment AE

Violation Relaxation Limit Values (VRLs)

This Addendum 1 to Attachment AE sets forth the Violation Relaxation Limit Values (VRLs) to be used in conjunction with the operation of the SPP Energy Imbalance Service Market.

Violation Category	VRL $ Level and Unit of Violation
Operational Constraint (Loading) Limit Block 1	$500 per MW when the loading is greater than 100% and less than or equal to 101% at each network constraint (called operating constraints or OCs)
Operational Constraint (Loading) Limit Block 2	$750 per MW when the loading is greater than 101% and less than or equal to 102% at each network constraint (called operating constraints or OCs)
Operational Constraint (Loading) Limit Block 3	$1,000 per MW when the loading is greater than 102% and less than or equal to 103% at each network constraint (called operating constraints or OCs)
Operational Constraint (Loading) Limit Block 4	$1,250 per MW when the loading is greater than 103% and less than or equal to 104% at each network constraint (called operating constraints or OCs)
Operational Constraint (Loading) Limit Block 5	$1,500 per MW when the loading is greater than 104% at each network constraint (called operating constraints or OCs)
Resource Ramp Rate Limit	$5,000 per MW* at each resource
Generation –to-Load Balance	$50,000 per MW within each dispatch solution
Resource Maximum/Minimum Limit	$100,000 per MW at each resource

*Generally as quantified across a five-minute EIS Market deployment interval.

Effective Date: 3/25/2011 - Docket #: ER11-2736

Southwestern Public Service Company
SPP Energy Charges
For 2013 and 2014, Based on CY 2012

Line No.	Description	2012 $	NM Allocator	NM %	Total NM Retail
1	Energy Imbalance	$ (140,214)	ENERGY	18.307%	$ (25,669)
2	Over Scheduling	43,126	ENERGY	18.307%	$ 7,895
3	Under Scheduling	242,111	ENERGY	18.307%	$ 44,323
4	UD	23,275	ENERGY	18.307%	$ 4,261
5	RNU	(821,417)	ENERGY	18.307%	$ (150,377)
6	Losses - Self Provided	209	ENERGY	18.307%	$ 38
7	Losses - Financial	175,006	ENERGY	18.307%	$ 32,038
8	Misc	-	ENERGY	18.307%	$ -
9	Total	$ (477,904)			$ (87,490)

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, SOUTHWESTERN PUBLIC SERVICE COMPANY, Respondent.	)	CASE NO. 07-00390-UT

SOUTHWESTERN PUBLIC SERVICE COMPANY'S NOTICE OF CHANGE IN THE SOUTHWEST POWER POOL ADMINISTRATION SERVICE CHARGE

The Uncontested Stipulation ("Stipulation") approved by the Public Regulation Commission ("Commission") in this case[1] requires Southwestern Public Service Company ("SPS") to provide the Commission with notice if the Southwest Power Pool ("SPP") Tariff Administration Service Charge ("Administration Charge" or "Charge") increases by more than 25% above $0.19 per megawatt-hour ("MWh"), which was the level of the Charge as of October 16, 2007.[2] SPS is required to provide notice of the increase above 25% within 60 days of the date the Federal Energy Regulatory Commission ("FERC") accepts the SPP's proposed change in the Charge.[3] The Administration Charge is designed to cover the SPP's operating and debt service costs, *i.e.*, administrative expenses.

[1] Final Order Approving Certificate of Stipulation (Feb. 2, 2010) ("Order").

[2] Stipulation at 3, Section 3.

[3] Stipulation at 3, Section 3.

The FERC accepted a change in the SPP's Administration Charge on December 14, 2011. The revised Charge in 2012 is $0.255 per MWh and became effective on January 1, 2012.[4] Attachment 1 to this notice is a copy of the explanation and calculation the SPP provided to the FERC for the revised Charge of $0.255 per MWh. Attachment 2 to this notice is a copy of the FERC's acceptance of the revised tariff sheets increasing SPP's rate cap of Schedule 1-A Tariff Administration Service Charge. The Schedule 1-A tariff that the SPP submitted and that the FERC approved in Attachment 2 sets a cap of $0.35 per MWh on the Administration Charge, but the SPP will charge less than that cap in 2012, *i.e.*, $0.255 per MWh.

The increase in the Administration Charge to $0.255 per MWh (a 34.2% increase above the level of the Charge as of October 16, 2007) triggers the notice requirement in the Stipulation. Thus, SPS provides the Commission with this notice within the time required under the Stipulation.

The SPP is required to recover 100% of its annual administrative expenses through the Administration Charge. Thus, as SPP's administrative expenses increase, the Charge increases. The most significant cost driver for the increase in the SPP's 2012 Administration Charge is the increasing level of activity (additional personnel, travel, the need for consulting services, organizing and conducting meetings, etc.) to develop and begin to operate the Integrated Marketplace project. The Integrated Marketplace project is intended to improve the efficiency of the wholesale power market by, as examples, increasing support for the transmission congestion rights function, the day-ahead market

[4] This recent change to $0.255 per MWh is not the first change that has occurred in the Charge since the Commission issued its Order. Through December 31, 2011, the Charge was $0.210 per MWh, which was a 10.5% increase over the $0.19 per MWh Charge as of October 16, 2007.

program, the real-time balancing function, the reliability unit commitment program, and the operating reserves market program.

SPS has been a member of the SPP since October 1973. All of SPS's load has been subject to the Administration Charge since October 2004 when the SPP became a regional transmission organization ("RTO"). As a member of the SPP RTO, SPS receives the following major services that are essential to the operation and reliability of SPS's transmission system:

(1) independent reliability coordination and transmission tariff administration;

(2) regional engineering, planning, and operation studies;

(3) reliability assessment studies;

(4) a telecommunications network to maintain transmission system and generation system reliability;

(5) regional transaction scheduling;

(6) access to an Energy Imbalance Service short-term wholesale market; and

(7) enforcement of mandatory North American Electric Reliability Corporation electric reliability standards.

SPS's customers, including SPS's New Mexico retail customers, benefit from SPS's participation in the SPP, which enables SPS to (1) operate and provide a reliable transmission system and (2) have access to a short-term wholesale power market to help SPS meet unplanned hourly capacity and energy needs due to the unexpected immediate unavailability of generation resources or unexpected short-term spikes in customer demand or usage.

The Commission has approved SPS's participation in the SPP RTO for a five-year interim period through February 2, 2015.[5] Under the Commission's Order and the Stipulation, SPS is required to file a detailed report with the Commission by February 2, 2013, regarding the merits of SPS's continued participation in the SPP RTO.[6] Thus, in slightly less than a year from the date of this notice, the Commission will have the opportunity to review and consider the benefits and costs, including the Administration Charge, of SPS's participation in the SPP RTO in conjunction with determining whether the interim approval for SPS to participate in the SPP RTO should be extended. In addition, the increase in the SPP Administration Charge that became effective on January 1, 2012 is not reflected in the current base rates SPS charges its New Mexico retail customers.

As required by the Commission's Order and the Stipulation, SPS is serving a copy of this notice on all parties in this case.

Respectfully submitted,

Jeffrey L. Fornaciari
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[5] Order at 2, Ordering ¶ A; Certification of Stipulation at 50, Ordering ¶ A; Stipulation at 3, Section 2.

[6] Stipulation at 4, Section 4.

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ATTORNEYS FOR SOUTHWESTERN PUBLIC SERVICE COMPANY

SPP Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

December 15, 2011

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***Southwest Power Pool, Inc.*, Docket Nos. RT04-1-000 & -001, ER04-48-000 & -001, and ER08-1338-000**
Submission of Annual Operating Budget Informational Filing

Dear Secretary Bose:

Pursuant to the Commission's October 1, 2004 Order on Rehearing of Southwest Power Pool, Inc.'s ("SPP") application for recognition as a Regional Transmission Organization ("RTO")[1] and commitments made by SPP in Docket No. ER08-1338-000, SPP hereby submits on an informational basis its annual operating budget for 2012, including information reflecting its 2011 expenses and revenues.

Background

The October 1 Order granted in part and denied in part rehearing on various issues related to the Commission's recognition of SPP as an RTO.[2] One of the directives to SPP in the October 1 Order was that SPP must annually file its operating budget on an informational basis.[3] Additionally, on July 31, 2008, SPP filed revisions to Schedule 1-A of its Open Access Transmission Tariff ("Tariff") in order to increase the cap imposed on its Tariff Administration Charge.[4] In requesting an increase in the cap, SPP committed to provide information regarding its prior year costs and transmission volumes as part of its annual operating budget informational filing in order to provide greater transparency in

1 *Sw. Power Pool, Inc.*, 109 FERC ¶ 61,010 (2004) ("October 1 Order").

2 *See generally id.*

3 *Id.* at P 98.

4 Filing of Revised Tariff Sheets to Increase Cap on Schedule 1-A Administration Charge of Southwest Power Pool, Inc., Docket No. ER08-1338-000 (Jul. 31, 2008) ("July 31 Filing"). The July 31 Filing was accepted by Letter Order on September 18, 2008. *Sw. Power Pool, Inc.*, Letter Order, Docket No. ER08-1338-000 (Sept. 18, 2008).

415 North McKinley Street, Suite 140 | Little Rock, AR 72205 | 501-614-3200 | SPP.org

the budget process.[5] SPP submits the instant filing to comply with the October 1 Order and commitments made in the July 31 Filing.

SPP's 2012 Operating Budget and Assessment Charge

Each year, SPP prepares an annual budget for the upcoming year and forecasts for subsequent years utilizing certain assumptions, including adjustments for inflation and anticipation of any new regulatory requirements. SPP also estimates the amount of service (in MWh) it expects to sell under its Tariff in the upcoming year, based on prior year sales adjusted by an escalation factor based upon the Energy Information Administration ("EIA") EIA-411 report. From its annual budget, SPP determines its net revenue requirements (total cash outflows, excluding capital expenditures, minus revenues realized from other sources). Once the net revenue requirement is known, SPP's Board of Directors establishes the Tariff Administration Charge for the upcoming year, taking into account SPP's net revenue requirement for the upcoming year and any over-collection or under-collection in the current year.

The Tariff Administration Charge is designed to ensure that SPP recovers all of its costs and that its customers do not pay more than necessary to allow full recovery, pursuant to Schedule 1-A of the SPP Tariff.[6] As demonstrated in Exhibit No. 1, SPP projects a net revenue requirement of $89,560,000 and sales of 353,453,000 MWh for the 2012 operating year, resulting in a Tariff Administration Charge of $0.255 per MWh,[7] less than the $0.35 per MWh cap approved by the Commission.[8] SPP's Board of Directors approved the annual budget and a Tariff Administration Charge of $0.255 on October 25, 2011.

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[5] July 31 Filing at 2. Exhibit No. 1 to this filing also shows prior year costs and transmission volumes. Because SPP's Annual Budget was established in October, 2011 for the 2012 operating year, Exhibit No. 1 contains both actual (to the extent available) and forecasted information in the "2011 Forecast" column.

[6] *See* Southwest Power Pool, FERC Electric Tariff, Sixth Revised Volume No. 1 at Schedule 1-A ("SPP Tariff"). Schedule 1-A requires SPP to recover 100% of its administrative expenses through the Tariff Administration Charge.

[7] The calculated Tariff Administration Charge of $0.253 per MWh, reflected in Exhibit No. 1, was rounded up to $0.255 per MWh for the 2012 Tariff Administration Charge.

[8] *Sw. Power Pool, Inc.*, Letter Order, Docket No. ER12-277-000 (Dec. 14, 2011) (accepting SPP's proposal to set a Tariff Administration Charge cap of $0.35 per MWh).

The Honorable Kimberly D. Bose
December 15, 2011
Page 3

Communications & Service

SPP requests that all correspondence and communications regarding this filing be sent to the following:

Heather H. Starnes, J.D.
Manager, Regulatory Policy
Southwest Power Pool, Inc.
415 North McKinley, Suite 140
Little Rock, AR 72205
Telephone: (501) 614-3380
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hstarnes@spp.org

Tessie Kentner
Southwest Power Pool, Inc.
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Little Rock, AR 72205
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Fax: (501) 603-0284
tkentner@spp.org

SPP has served a copy of this filing on all parties to the service lists in the listed proceedings, as well as providing a copy to all of its members and customers and the state commissions in the SPP region.

Conclusion

Please contact the undersigned if you have any questions regarding the contents of this informational filing.

Respectfully submitted,

/s/ Tessie Kentner
Tessie Kentner
Southwest Power Pool, Inc.

Attorney for
Southwest Power Pool, Inc.

cc: Penny Murrell
Michael Donnini
John Rogers
Patrick Clarey
Laura Vallance

Exhibit No. 1

SPP Southwest Power Pool

SOUTHWEST POWER POOL
2012 BUDGET & 2011 FORECAST

(000's)	2012 Budget	2011 Forecast
Income		
Tariff Administration Service	$90,131	$71,391
Fees & Assessments	26,909	23,793
Contract Services Revenue	23,758	27,076
Miscellaneous Income	5,616	5,522
Total Income	**146,414**	**127,781**
Expense		
Salary & Benefits	72,222	64,321
Employee Travel	3,002	1,787
Administrative	4,212	3,147
Assessments & Fees	15,410	16,639
Meetings	1,445	931
Communications	4,592	3,412
Leases	1,631	1,870
Maintenance	9,312	7,144
Services	18,700	14,374
Regional State Committee	394	181
Depreciation & Amortization	17,317	16,121
Other Expense	3,716	6,042
Total Expense	**151,954**	**135,969**
Net Income (Loss)	**($5,540)**	**($8,188)**
Debt Repayment	$11,206	$13,206
MW/h Forecast	353,453	339,993
Net Revenue Requirement	$89,560	$76,664
Calculated Admin Fee / MWh	$0.253	$0.225
Recommended Admin Fee / MWh	$0.255	$0.210
Capital Expense	$82,034	$90,090
Headcount	590	540

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Little Rock, AR this 15th day of December, 2011.

/s/ Tessie Kentner
Tessie Kentner

Attorney for
Southwest Power Pool, Inc.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Southwest Power Pool, Inc.
Docket No. ER12-277-000

December 14, 2011

Southwest Power Pool, Inc.
Attention: Matthew Harward, Attorney
415 North McKinley, #140 Plaza West
Little Rock, AR. 72205

Reference: Revised Tariff Sheet Increasing Rate Cap of Schedule 1-A Tariff Administration Service Charge

Dear Mr. Harward:

On October 31, 2011, you filed on behalf of Southwest Power Pool, Inc. (SPP) revised tariff sheets increasing SPP's rate cap of Schedule 1-A Tariff Administration Service Charge from \$0.225/MWh to \$0.35/MWh. Pursuant to authority delegated to the Director, Division of Electric Power Regulation – Central, under 18 C.F.R. § 375.307, your submittal in the above referenced docket is accepted for filing effective January 1, 2012, as requested.

Notice of the filing was published in the Federal Register with interventions or protests due on or before November 21, 2011. No adverse comments or protests were filed. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motion to intervene is governed by the provisions of Rule 214.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against any of the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of the issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power
Regulation - Central

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, SOUTHWESTERN PUBLIC SERVICE COMPANY, Respondent.	CASE NO. 07-00390-UT

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of Southwestern Public Service Company's Notice of Change in the Southwest Power Pool Administration Service Charge was served on the following parties by electronic mail on this 13th day of February, 2012:

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ATTORNEYS FOR SOUTHWESTERN PUBLIC SERVICE COMPANY

SOUTHWESTERN PUBLIC SERVICE COMPANY
(Xcel Energy)

NMPRC CASE NO. 07-00390-UT

IN ACCORDANCE WITH SECTION 11 OF THE UNCONTESTED STIPULATION REQUIRING SOUTHWESTERN PUBLIC SERVICE COMPANY ("SPS") TO FILE AN ANNUAL REPORT

2012 Annual Report

(1) The Southwest Power Pool ("SPP") administrative charges (SPP Schedule 1-A) for the prior calendar year;

The SPP administrative fees charged to SPS in 2011 were as follows:

FERC Account	Total SPS	NM Retail
561.4	$3,618,675	$549,039
561.8	$664,665	$100,844
575.7	$3,101,721	$450,864
Total	*$7,385,050*	*$1,100,747*

(2) The ancillary services charges (SPP Schedule 2) reimbursed to SPS for the prior calendar year;

The SPP Schedule 2 charges and revenues incurred and received by SPS in 2011 were:

FERC Account	Total SPS	NM Retail*
565.50	$348,899	$103
456.14	($755,739)	($69,248)
Total	*($406,840)*	*($69,145)*

* In 2011, the majority of Schedule 2 costs were attributable to network transactions and thus were assigned to SPS's wholesale jurisdiction. SPS received Schedule 2 revenues under both the SPP and Xcel Energy Open Access Transmission Tariffs. The majority of the revenue was attributable to network transactions and thus assigned to SPS's wholesale jurisdiction. However, SPS also received Schedule 2 revenues for point-to-point transactions, which are shared between all of SPS's jurisdictions.

(3) 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;

The Base Plan Upgrade ("BPU") charges and revenues in 2011 were:

FERC Account	Description	Total SPS	NM Retail
565.15	BPU Charges – Constructed by SPS	$5,736,103	$1,084,603
565.15	BPU Charges – Constructed by Other SPP Members	$5,410,620	$1,023,060
456.99	BPU Revenues – Constructed by SPS (Shown as a Negative)	($8,599,141)	($1,275,024)
	Net Total	*$2,547,582*	*$832,639*

(4) **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);**

The Balanced Portfolio charges and revenues to SPS in 2011 were:

FERC Account	Description	Total SPS	NM Retail
565.15	Balance Portfolio Charges – Constructed by SPS	$0	$0
565.15	Balance Portfolio Charges – Constructed by Other SPP Members	$0	$0
456.99	Balance Portfolio Revenues – Constructed by SPS (Shown as a Negative)	$0	$0
	Net Total	*$0*	*$0*

(5) **Costs and revenues related to the operation of the SPP EIS Market for the prior calendar year;**

The costs of operating the SPP EIS Market that were charged to SPS are included in FERC Account 575.7. SPP does not separately identify the EIS market administration costs from the SPP monitoring and compliance costs, therefore, SPS cannot separately identify the EIS Market costs. As mentioned in item (1), above, the total costs recorded for 2011 were as follows:

FERC Account	Total SPS	NM Retail
575.7	$3,101,721	$450,864

The SPP EIS Market is settled on a net basis. The net amount of the costs and revenues to SPS in 2011 was:

FERC Account	Total SPS	NM Retail
555	$22,660,080	$3,700,912

(6) Allocation of SPP FERC assessment fees (SPP Schedule 12) for the prior calendar year; and

The SPP FERC Assessment fees charged to SPS in 2011 were:

FERC Account	Total SPS	NM Retail
565.15	$1,973,616	$349,001

(7) The charges from SPP to SPS for ancillary services not self-provided by SPS for the prior calendar year.

The ancillary service charges to SPS for 2011 were as follows:

FERC Account	Description	Total SPS	NM Retail
565.50	Sch 1 (Scheduling)	$619,496	$1,849
565.50	Sch 2 (Reactive)	$348,899	$103
565.50	Sch 3 (Regulation)	$0	$0
555	Sch 4 (Energy Imbalance)	$22,660,080	$3,700,912
565.50	Sch 5 (Spinning)	$0	$0
565.50	Sch 6 (Supplemental)	$0	$0
	Total	*$23,628,476*	*$3,702,864*

SOUTHWESTERN PUBLIC SERVICE COMPANY
(Xcel Energy)

NMPRC CASE NO. 07-00390-UT

IN ACCORDANCE WITH SECTION 11 OF THE UNCONTESTED STIPULATION REQUIRING SOUTHWESTERN PUBLIC SERVICE COMPANY ("SPS") TO FILE AN ANNUAL REPORT

2011 Annual Report

(1) The Southwest Power Pool ("SPP") administrative charges (SPP Schedule 1-A) for the prior calendar year;

The SPP administrative fees charged to SPS in 2010 were as follows:

FERC Account	Total SPS	NM Retail
561.4	$3,520,673	$453,086
561.8	$646,152	$83,194
575.7	$3,028,278	$382,484
Total	*$7,195,103*	*$918,764*

(2) The ancillary services charges (SPP Schedule 2) reimbursed to SPS for the prior calendar year;.

The SPP Schedule 2 charges and revenues incurred and received by SPS in 2010 were:

FERC Account	Total SPS	NM Retail*
565.15	$286,565	$0
456.14	($1,091,515)	($52,924)
Total	*($804,950)*	*($52,924)*

* In 2010, the Schedule 2 costs were attributable to network transactions and thus were assigned to SPS's wholesale jurisdiction. SPS received Schedule 2 revenues under both the SPP and Xcel Energy Open Access Transmission Tariffs. The majority of the revenue was attributable to network transactions and thus would be assigned to SPS's wholesale jurisdiction; however, SPS received Schedule 2 revenues for point-to-point transactions, which are shared between all of SPS's jurisdictions.

(3) 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;

The Base Plan Upgrade ("BPU") charges and revenues in 2010 were:

FERC Account	Description	Total SPS	NM Retail
565.15	BPU Charges – Constructed by SPS	$1,165,796	$174,457
565.15	BPU Charges – Constructed by Other SPP Members	$2,913,431	$435,984
456.99	BPU Revenues – Constructed by SPS (Shown as a Negative)	($1,645,643)	($246,264)
	Net Total	*$2,433,584*	*$364,177*

(4) **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);**

The Balanced Portfolio charges and revenues to SPS in 2010 were:

FERC Account	Description	Total SPS	NM Retail
565.15	Balance Portfolio Charges – Constructed by SPS	$0	$0
565.15	Balance Portfolio Charges – Constructed by Other SPP Members	$0	$0
456.99	Balance Portfolio Revenues – Constructed by SPS (Shown as a Negative)	$0	$0
	Net Total	*$0*	*$0*

(5) **Costs and revenues related to the operation of the SPP EIS Market for the prior calendar year;**

The costs of operating the SPP EIS Market that were charged to SPS are included in FERC Account 575.7. SPP does not separately identify the EIS market administration costs from the SPP monitoring and compliance costs, therefore, SPS cannot separately identify the EIS Market costs. As mentioned in item (1), above, the total costs recorded for 2010 were as follows:

FERC Account	Total SPS	NM Retail
575.7	$3,028,278	$382,484

The SPP EIS Market is settled on a net basis. The net amount of the costs and revenues to SPS in 2010 was:

FERC Account	Total SPS	NM Retail
555	$34,143,936	$5,436,769

(6) **Allocation of SPP FERC assessment fees (SPP Schedule 12) for the prior calendar year; and**

The SPP FERC Assessment fees charged to SPS in 2010 were:

FERC Account	Total SPS	NM Retail
565.15	$1,636,943	$301,844

(7) **The charges from SPP to SPS for ancillary services not self-provided by SPS for the prior calendar year.**

The ancillary service charges to SPS for 2010 were as follows:

FERC Account	Description	Total SPS	NM Retail
565.15	Sch 1 (Scheduling)	$1,114,565	$0
565.15	Sch 2 (Reactive)	$286,565	$0
565.15	Sch 3 (Regulation)	$0	$0
555	Sch 4 (Energy Imbalance)	$34,143,936	$5,436,769
565.15	Sch 5 (Spinning)	$0	$0
565.15	Sch 6 (Supplemental)	$0	$0
	Total	*$35,545,066*	*$5,436,769*

SOUTHESTERN PUBLIC SERVICE COMPANY
(Xcel Energy)

NMPRC CASE NO. 07-00390-UT

IN ACCORDANCE WITH SECTION 11 OF THE UNCONTESTED STIPULATION REQUIRES SOUTHWESTERN PUBLIC SERVICE COMPANY (SPS) TO FILE AN ANNUAL REPORT

2010 Annual Report

(1) **The Southwest Power Pool (SPP) administrative charges (SPP Schedule 1-A) for the prior calendar year;**

The SPP Administrative fees charged to SPS (total company) in 2009 (FERC Accounts 561.4, 561.8, 575.7): $1,925,368

(2) **The ancillary services charges (SPP Schedule 2) reimbursed to SPS for the prior calendar year;**

Schedule 2 revenue received by SPS (total company) in 2009 from the SPP (FERC Account 45614): $1,442,918

(3) **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;**

Base Plan Upgrade charges to SPS (total company) recorded in 2009: $1,544,986

(4) **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);**

Balanced Portfolio charges to SPS (total company) recorded in 2009: $0

(5) **Costs and revenues related to the operation of the SPP EIS Market for the prior calendar year;**

The SPP EIS Market is settled on a net basis for calendar year 2009. The net amount of the costs and revenues to SPS is a $16,923,885.52 expense (total company)

(6) **Allocation of SPP FERC assessment fees (SPP Schedule 12) for the prior calendar year; and**

SPP FERC Assessment fees charged to SPS (total company) in 2009 (FERC Account 56515): $1,551,891

(7) **The charges from SPP to SPS for ancillary services not self-provided by SPS for the prior calendar year.**

2009 Ancillary Services charges to SPS (total company) from the SPP --

Schedule 1 (Scheduling): $756,403

Schedule 2 (Reactive): $739,105

Schedule 3 (Regulation): $0

Schedule 4 (Energy Imbalance): See response to question 5, above

Schedule 5 (Spinning Reserves): $0

Schedule 6 (Supplemental Reserves): $0