at a later date to discuss any project-related effects to archaeological, historic, or traditional cultural properties.

Meeting Objectives

At the scoping meetings, staff will: (1) Summarize the environmental issues tentatively identified for analysis in the EA; (2) solicit from meeting participants all available information, especially quantifiable data, on the resources at issues; (3) encourage statements from experts and the public on issues that should be analyzed in the EA, including viewpoints in opposition to, or in support of, the staff's preliminary views; (4) determine the resource issues to be addressed in the EA; and (5) identify those issues that require a detailed analysis, as well as those issues that do not require a detailed analysis.

Meeting Procedures

Scoping meetings will be recorded by a stenographer and will become part of the Commission's formal record for this proceeding.

Individuals, organizations, and agencies with environmental expertise and concerns are encouraged to attend the meetings and to assist staff in defining and clarifying the issues to be addressed in the EA.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–30811 Filed 12–28–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PR10–4–000]

Cranberry Pipeline Corporation; Notice of Petition for Rate Approval

December 22, 2009.

Take notice that on December 15, 2009, Cranberry Pipeline Corporation (Cranberry) filed pursuant to section 284.123(b)(2) of the Commission's regulations, a petition requesting that the Commission approve its request to retain its existing interruptible transportation rate and firm and interruptible storage rates pursuant to section 311 of the Natural Gas Policy Act of 1978. Further, Cranberry requests approval to retain its existing fuel and lost and unaccounted for percentage for transportation and services.

Any person desiring to participate in this rate proceeding must file a motion to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the date as indicated below. Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern time, Monday, January 4, 2010.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–30812 Filed 12–28–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division-Rate Order Nos. WAPA–144 and WAPA–148

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Order Concerning Transmission and Ancillary Services Rates and Transmission Service Penalty Rate for Unreserved Use.

SUMMARY: The Deputy Secretary of Energy confirmed and approved Rate Order Nos. WAPA–144 and WAPA–148 and Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–AS7 and UGP–TSP1 on an interim basis. The provisional rates will be in effect until the Federal Energy Regulatory Commission (FERC) confirms, approves, and places them into effect on a final basis or until they are superseded. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expenses, and repay required investments within the allowable periods.

DATES: Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6 and will be placed into effect on an interim basis on January 1, 2010, and will be in effect until FERC confirms, approves, and places the rate schedules in effect on a final basis through December 31, 2014, or until the rate schedules are superseded. The revised Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5 and UGP–AS6 dated January 1, 2010, supersede the similarly titled rate schedules dated October 1, 2005. Rate Schedule UGP–AS7 will be placed into effect on an interim basis on January 1, 2010; however, Rate Schedule UGP–AS7 will not be charged until such time as Western's OATT is revised to provide for Generator Imbalance Service. Rate Schedule UGP–AS7 will remain in effect through December 31, 2014, or until superseded, to coincide with the other ancillary service rates in this rate order. Rate Schedule UGP–TSP1 will be placed into effect on an interim basis on January 1, 2010; however, Rate Schedule UGP–TSP1 will not be charged until such time as Western's Open Access Transmission Tariff (OATT) is revised to provide for unreserved use of transmission service penalties. Rate schedule UGP–TSP1 will also remain in effect through December 31, 2014, or until superseded, to coincide with the other rates in this rate order. Western will post notice on its Open Access Same-Time Information System (OASIS) Web site of its intent to initiate charging for Rate Schedule UGP–AS7 or UGP–TSP1.

FOR FURTHER INFORMATION CONTACT: Mr. Robert J. Harris, Regional Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266 or Ms. Linda Cady-Hoffman, Rates Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT

59101–1266, telephone (406) 247–7439, e-mail *cady@wapa.gov.*

SUPPLEMENTARY INFORMATION: The transmission facilities in the Pick-Sloan Missouri Basin Program—Eastern Division (P–SMBP—ED) are integrated with transmission facilities of Basin Electric Power Cooperative (Basin) and Heartland Consumers Power District (Heartland) such that transmission services are provided over an Integrated System (IS), and the rates are sometimes referred to as IS Rates. Western acts as the administrator of the IS and monitors service under the OATT.[1] As owners of the IS, Western, Basin, and Heartland may be referred to as IS Partners. The Deputy Secretary of Energy approved the current Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6 for P–SMBP—ED firm and non-firm transmission rates and ancillary services rates through September 30, 2010.[2] The current rate schedules contain formula-based rates that are recalculated annually. The provisional formula rates will continue to be recalculated annually from financial and load information. Provisional rates will go into effect January 1, 2010, and recalculated rates annually on January 1 thereafter. The provisional rate for Generator Imbalance Service, under UGP–AS7, will go into effect January 1, 2010, but will not be charged until Western's OATT is revised to provide for Generator Imbalance Service. The provisional Penalty Rate for Unreserved Use of Transmission Service, under UGP–TSP1 will go into effect on January 1, 2010, but will not be charged until Western's OATT is revised to provide for unreserved use penalties. Western will post notice on its Open Access Same-Time Information System (OASIS) Web site of its intent to initiate charging for Rate Schedule UGP–AS7 or UGP–TSP1.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Under Delegation Order Nos. 00–037.00 and 00–001.00C, 10 CFR part 903, and 18 CFR part 300, I hereby confirm, approve, and place Rate Order Nos. WAPA–144, the proposed P–SMBP—ED Integrated System firm and non-firm transmission rates and ancillary services and WAPA–148, the proposed Transmission Service Penalty Rate for Unreserved Use into effect on an interim basis. The new Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–AS7 and UGP–TSP1 will be promptly submitted to the Commission for confirmation and approval on a final basis.

Dated: December 23, 2009.

Daniel B. Poneman,

Deputy Secretary.

Department of Energy Deputy Secretary

Rate Order Nos. WAPA–144 and WAPA–148

In the matter of: Western Area Power Administration Rate Adjustment for the Pick-Sloan Missouri Basin Program—Eastern Division; Order Confirming, Approving, and Placing the Pick-Sloan Missouri Basin Program—Eastern Division Transmission and Ancillary Services and Transmission Service Penalty for Unreserved Use Formula Rates Into Effect on an Interim Basis.

This rate was established in accordance with section 302 of the Department of Energy (DOE) Organization Act (42 U.S.C. 7152). This Act transferred to and vested in the Secretary of Energy the power marketing functions of the Secretary of the Department of the Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), and other Acts that specifically apply to the project involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to the Federal Energy Regulatory Commission (FERC). Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Acronyms and Definitions

As used in this Rate Order, the following acronyms and definitions apply:

$/kWmonth: Monthly charge for capacity (*i.e.,* $ per kilowatt (kW) per month).

12-cp: 12-month coincident peak average.

Administrator: The Administrator of the Western Area Power Administration.

Ancillary Services: Those services necessary to support the transfer of electricity while maintaining reliable operation of the Transmission System in accordance with standard utility practice.

A&GE: Administrative and general expense.

ATRR: Annual Transmission Revenue Requirement.

Balancing Authority: An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Balancing Authorities and contributing to frequency regulation of the Interconnection. Formerly known as control area.

Basin Electric: Basin Electric Power Cooperative.

Capacity: The electric capability of a generator, transformer, transmission circuit, or other equipment. It is expressed in kilowatts.

Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) Match, at all times, the power output of the generators within the electric system(s) and capacity and energy purchased from entities outside the electric power system(s) with load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Corps of Engineers: U.S. Army Corps of Engineers.

[1] Western's OATT was most recently approved by FERC on June 28, 2007, in Docket No. NJ07–2–000, 119 FERC 61,329 (2007) and the FERC's letter order issued on September 6, 2007, in Docket No. NJ07–2–001.

[2] Rate Order No. WAPA–122, 70 FR 55821, September 23, 2005, and the FERC confirmed and approved the rate schedules on May 30, 2006, under FERC Docket No. EF05–5031–000, 115 FERC ¶ 62,230.

Customer: An entity with a contract that is receiving service from Western Area Power Administration's Upper Great Plains Region.

DOE: United States Department of Energy.

Energy: Power produced or delivered over a period of time. Measured in terms of the work capacity over a period of time. It is expressed in kilowatthours.

Emergency Energy: Electric energy purchased by an electric utility whenever an event on the system causes insufficient operating capability to cover its own demand requirement.

Energy Imbalance Service: A service which provides energy correction for any hourly mismatch between a Transmission Customer's energy supply and the demand served.

Energy Rate: The rate which sets forth the charges for energy. It is expressed in mills per kilowatthour and applied to each kilowatthour delivered to each customer.

FERC: The Federal Energy Regulatory Commission.

FERC Order No. 888: FERC Order Nos. 888, 888–A, 888–B and 888–C unless otherwise noted.

FERC Order No. 890: FERC Order Nos. 890, 890–A, 890–B and 890–C unless otherwise noted.

Firm: A type of product and/or service available at the time requested by the customer.

Firm Point-to-Point: Service that is reserved and/or scheduled between Points of Receipt and Delivery.

FRN: **Federal Register** notice.

FY: Fiscal year; October 1 to September 30.

GWh: Gigawatthour—the electrical unit of energy that equals 1 billion watthours or 1 million kilowatt-hours.

Heartland: Heartland Consumers Power District.

Integrated System: Transmission system combining assets of Western, Basin Electric, and Heartland.

IS: Integrated System.

Intermittent Resource: An electric generator that is not dispatchable and cannot store its fuel source and, therefore, cannot respond to changes in demand or respond to transmission security constraints.

kW: Kilowatt—the electrical unit of capacity that equals 1,000 watts.

kWh: Kilowatthour—the electrical unit of energy that equals 1,000 watts in 1 hour.

kWmonth: Kilowattmonth—the electrical unit of the monthly amount of capacity.

kWyear: Kilowattyear—the electrical unit of the yearly amount of capacity.

Load: The amount of electric power or energy delivered or required at any specified point(s) on a system.

Load-ratio share: Ratio of the Network Transmission Customer's coincident hourly load (including its designated network load not physically interconnected with the Transmission Provider) to the Transmission Provider's monthly Transmission System peak, calculated on a rolling 12-month basis.

Long-Term Firm Point-to-Point: Firm Point-to-Point Transmission Service reservation with at least 12 consecutive equal monthly amounts.

MAPP: Mid-Continent Area Power Pool.

Mill: A monetary denomination of the United States that equals one tenth of a cent or one thousandth of a dollar.

Mills/kWh: Mills per kilowatthour—the unit of charge for energy.

MW: Megawatt—the electrical unit of capacity that equals 1 million watts or 1,000 kilowatts.

NERC: North American Electric Reliability Council.

Net Revenue: Revenue remaining after paying all annual expenses.

Network Customer: An entity receiving Transmission Service under the terms of the Transmission Provider's Network Integration Transmission Service of the Tariff.

Non-Firm Point-to-Point: Point-to-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to interruption for economic reasons.

O&M: Operation and maintenance.

OASIS: Open Access Same-Time Information System—provides access to information on transmission pricing and availability for potential transmission customers.

P–SMBP: Pick-Sloan Missouri Basin Program.

P–SMBP—ED: Pick-Sloan Missouri Basin Program—Eastern Division.

Point-to-Point: The reservation and transmission of capacity and energy on either a firm or non-firm basis from designated Point(s) of Receipt to designated Point(s) of Delivery.

Power: Capacity and energy.

Provisional Rate: A rate which has been confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary.

Rate Brochure: Documents explaining the rationale and background for the rate proposals contained in this Rate Order.

Reclamation: United States Department of the Interior, Bureau of Reclamation.

Reactive Supply and Voltage Control Service: A service which provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

Regulation and Frequency Response Service: A service which provides for following the moment-to- moment variations in the demand or supply in a Control Area and maintaining scheduled interconnection frequency.

Reserve Services: Spinning Reserve Service and Supplemental Reserve Service.

Revenue Requirement: The revenue required to recover annual expenses (such as O&M, purchase power, transmission service expenses, interest, and deferred expenses) and repay Federal investments, and other assigned costs.

Schedule: An agreed-upon transaction size (megawatts), beginning and ending ramp times and rate, and type of service required for delivery and receipt of power between the contracting parties and the Balancing Authority(ies) involved in the transaction.

Scheduling, System Control, and Dispatch Service: A service which provides for (a) scheduling, (b) confirming and implementing an interchange schedule with other balancing authorities, including intermediary balancing authorities providing transmission service, and (c) ensuring operational security during the interchange transaction.

Service Agreement: The initial agreement and any amendments or supplements entered into by the Transmission Customer and Western for service under the Tariff.

Short-Term Firm Point-to-Point: Firm Point-to-Point Transmission Service with service duration of less than one year.

Spinning Reserve Service: Generation capacity 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. The Transmission Provider must offer this service when the transmission service is used to serve load within its Balancing Authority. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation.

Supplemental Reserve Service: Generation capacity needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generation units that are on-line but unloaded, by quick start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Balancing Authority. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation.

Supporting Documents: A compilation of data and documents that support the Rate Brochure and the rate proposal.

System: An interconnected combination of generation, transmission and/or distribution components comprising an electric utility, independent power producer(s) (IPP), or group of utilities and IPP(s).

Tariff: Western Area Power Administration Open Access Transmission Service Tariff, originally approved in Docket No. NJ98–1–000, FERC 61,062 (2002) and amended in Docket No. NJ05–1–000, 112 FERC 61,044 (2005).

Transmission Customer: Any eligible customer (or its designated agent) that receives transmission service under the Tariff.

Transmission Provider: Any utility that owns, operates, or controls facilities used to transmit electric energy in interstate commerce. The Upper Great Plains Region, as operator of the IS, is the Transmission Provider for the purposes of this **Federal Register** notice.

Transmission System: The facilities owned, controlled, or operated by the Transmission Provider that are used to provide transmission service.

Transmission System Total Load: The 12-cp peak for Network Transmission Service plus reserved capacity for all Firm Point-to-Point Transmission Service.

UGPR: The Upper Great Plains Customer Service Region of the Western Area Power Administration. In some places in this order, UGPR maybe referenced generically as Western.

Unreserved Use: Use of transmission service in excess of reserved capacity at any point of receipt or any point of delivery.

VAR: A unit of reactive power.

WAUE: Western Area Power Upper Great Plains Region East Control Area.

WAUW: Western Area Power Upper Great Plains Region West Control Area.

Watertown Operation Office: Western Area Power Administration Upper Great Plains Customer Service Region, Operations Office, 1330 41st Street SE., Watertown, South Dakota.

Western: United States Department of Energy, Western Area Power Administration.

Western Regions: Customer service regions of the Western Area Power Administration.

Western's Tariff: Western's Open Access Transmission Service Tariff.

Effective Date

The provisional rates will take effect on January 1, 2010, and will remain in effect through December 31, 2014, pending approval by FERC on a final basis. Rate schedules UGP–AS7 and UGP–TSP1 will be placed into effect on an interim basis on January 1, 2010, but will not be charged until Western's Open Access Transmission Tariff (OATT) is revised to provide for Generator Imbalance Service and/or Transmission Service Penalty Rate for Unreserved Use. Western will post notice on its Open Access Same-Time Information System (OASIS) Web site of its intent to initiate charging for Rate Schedule UGP–AS7 or UGP–TSP1.

Public Notice and Comment

Western followed the Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR part 903, in developing these rates. The steps Western took to involve interested parties in the rate process were:

1. The rate adjustment process began when Western's UGPR mailed a notice announcing an Advance Announcement of Rate Adjustment public meeting to all IS Transmission Customers and interested parties. The meeting was held on June 10, 2008, in Sioux Falls, South Dakota. At the Advance Announcement of Rate Adjustment meeting, Western provided pertinent information relevant to the rate adjustment and answered questions.

2. A **Federal Register** notice published on June 3, 2009 (74 FR 26682), announced the proposed rate adjustments for P–SMBP–ED Transmission and Ancillary Service rates. This publication began a public consultation and comment period and announced the public information and the public comment forums.

3. A **Federal Register** notice published on June 26, 2009 (74 FR 30567), announced the proposed Transmission Service Penalty Rate for Unreserved Use. This publication began a public consultation and comment period and announced the public information and the public comment forums.

4. On June 5, 2009, Western mailed letters to all IS Transmission Customers and interested parties transmitting the **Federal Register** notice published on June 3, 2009, and directing them to the rate brochure for the Transmission and Ancillary Services Rate Adjustment on Western's Web site. On June 26, 2009, Western mailed letters to all IS Transmission Customers and interested parties transmitting the **Federal Register** notice published on June 26, 2009, and directing them to the rate brochure for the Transmission Service Penalty Rate for Unreserved Use on Western's Web site.

5. On June 24, 2009, beginning at 9 a.m., Western held a public information forum at the Holiday Inn City Center in Sioux Falls, South Dakota. Western provided detailed explanations of the proposed Transmission and Ancillary Service Rates. Western provided Rate Brochures, informational handouts and answered questions at this meeting.

6. On July 28, 2009, beginning at 8 a.m., Western held a public information forum at the Holiday Inn City Center Sioux Falls, South Dakota. Western provided detailed explanations of the proposed Transmission Service Penalty Rate for Unreserved Use. Western provided Rate Brochures, informational handouts, and answered questions at this meeting.

7. On July 28, 2009, beginning at 9 a.m., Western held a public comment forum at the Holiday Inn City Center Sioux Falls, South Dakota, to give the public the opportunity to comment for the record on the proposed Transmission and Ancillary Services Rates and the Transmission Service Penalty Rate for Unreserved Use.

8. Western received one comment letter during the consultation and comment period for proposed rates for P–SMBP–ED Transmission and Ancillary Service rates, which ended on October 1, 2009. Western received two comment letters during the consultation and comment period for proposed Transmission Service Penalty Rate for Unreserved Use, which ended on September 24, 2009. All formally submitted comments have been considered in preparing this Rate Order.

Comments

Representatives of the following organization made oral comments pertaining to the proposed P–SMBP–ED Transmission and Ancillary Service rates:

Missouri River Energy Services

The following organizations submitted written comments pertaining to the proposed P–SMBP–ED Transmission and Ancillary Service rates:

Missouri River Energy Services

The following organizations submitted written comments pertaining to the proposed P–SMBP–ED Transmission Service Penalty Rate for Unreserved Use rate:

Midwest ISO Transmission Owners

ITC Holdings Corp.

Project Description

The initial stages of the Missouri River Basin Project were authorized by section 9 of the Flood Control Act of 1944 (58 Stat. 887, 890, Pub. L. No. 78–534). It was later renamed the P–SMBP. The P–SMBP is a comprehensive program with the following authorized functions: flood control, navigation improvement, irrigation, municipal and industrial water development, and hydroelectric production for the entire Missouri River Basin. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota, and Wyoming.

The UGPR markets significant quantities of Federally-generated hydroelectric power from the P–SMBP–ED. Western owns and operates an extensive system of high-voltage transmission facilities which the UGPR uses to market approximately 2,400 MW of capacity from Federal projects within the Missouri River Basin. This capacity is generated by eight power plants located in Montana, North Dakota, and South Dakota. The UGPR uses the transmission facilities of Western and others to market this power and energy to customers located within the P–SMBP–ED. This marketing area includes Montana, east of the Continental Divide, all of North and South Dakota, eastern Nebraska, western Iowa, and western Minnesota.

Integrated System Description

Using a single system, joint-planning concept, Western, Basin Electric, and Heartland combined their transmission facilities to form the IS and developed Transmission and Ancillary Service rates for transmission over the IS. This action was necessary because the UGPR, Basin Electric, and Heartland, whose facilities are fully integrated, did not have rates suitable for long-term open access transmission service. The transmission facilities included in the IS are transmission lines, substations, communication equipment and facilities related to operation, maintenance, and support of the IS Transmission System. The UGPR is designated as the operator of the other participants' transmission facilities and as such contracts for service, determines and posts the available transmission capacity on the OASIS, bills for service, collects payments, and distributes revenues to each IS participant. The IS consists of the transmission facilities owned by Basin Electric and Heartland east of the east-west electrical separation in the United States, the transmission facilities owned by Western in the P–SMBP–ED, and the Miles City Converter Station owned by Western and Basin Electric. These facilities interconnect with utilities in the states of Montana, North Dakota, South Dakota, Iowa, Minnesota, Missouri, and in addition include facilities which interconnect with Canada.

The approach for formation of the IS was to include facilities which followed the spirit and intent of the FERC Order No. 888 and to make the system the most useful to all transmission requestors. The ''seven-factor test'' defined in FERC Order No. 888 was used to determine the distribution facilities that were excluded from the IS Transmission System.

P–SMBP–ED Transmission and Ancillary Services Rates Study

Western prepared a Transmission and Ancillary Service rates study to ensure that Formula IS Transmission and Ancillary Service rates are based on the cost of service of the IS Transmission System. This study includes all IS Transmission and Ancillary Service expenses and associated offsetting revenues.

In the past, rates have been based on the most recently available historical test year data. In preparing the current rates study, projections for the various revenue requirement components were used to develop the forward looking (projected) rate. The annual revenue requirements include O&M expenses, administrative and general expenses, interest expense, and depreciation expense. These revenue requirements are offset by appropriate estimated revenues. Annual audited financial data will be used to true-up the estimates used to project the forward looking rate to the actual expenses and load incurred.

Existing and Provisional Rates

The revenue requirements for the individual services and comparison values are outlined in the following table. These rates are calculated comparing the Existing Revenue Requirement to the Provisional Revenue Requirement based upon the most recent historical data available at the time of the initial rate proposal.

COMPARISON OF EXISTING AND PROVISIONAL INTEGRATED SYSTEM TRANSMISSION AND ANCILLARY SERVICES

Service	Existing revenue requirement	Provisional revenue requirement	Percentage change
Transmission	$155,056,530	$163,521,251	5.46
Scheduling, System Control, and Dispatch	3,649,053	3,649,053	0.00
Reactive Supply and Voltage Control	4,496,498	2,376,635	−47.14
Regulation and Frequency Control	1,362,791	1,362,791	0.00
Reserves	2,569,924	3,384,360	31.69
Energy Imbalance	N/A	N/A	N/A
Generator Imbalance	N/A	N/A	N/A
Transmission Service Penalty Rate for Unreserved Use	N/A	N/A	N/A

Certification of Rates

Western's Administrator certifies that the IS Transmission and Ancillary Service rates placed into effect on an interim basis are the lowest possible rates consistent with sound business principles. The provisional formula rates were developed following administrative policies and applicable laws.

Integrated System Transmission Service Rates Discussion

Western offers Network Integration Transmission, Firm Point-to-Point and Non-firm Point-to-Point Transmission, Scheduling, System Control, and Dispatch Service, Reactive Supply and Voltage Control Service, Regulation and Frequency Response Service, Energy Imbalance Service, and Reserve Service on the IS. The rate schedules for the IS were initially placed into effect by Rate Order No. WAPA–79 on August 1, 1998, and were effective through July 31, 2003. The FERC order to confirm these rate schedules was issued on November 25, 1998. These rate schedules were then extended by Rate Order No. WAPA–100 through September 30, 2005. Rate Order No. WAPA–122 removed the Generator Step Up Transformers from transmission and placed them in generation in the formula rate calculations. The rate schedules placed into effect by Rate Order No. WAPA–122 were effective on October 1, 2005, and will remain in effect until September 30, 2010, or until superseded.

The provisional formula rates include revisions to the Network Integration, Firm and Non-firm Transmission, and Ancillary Service Rates as described in Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6. These revisions will utilize estimates of transmission costs for the upcoming year to calculate annual revenue requirements, update formulas utilized in the formula rate calculations, change the effective date for rates resulting from the annual recalculation, provide a rate recalculation review/comment period, and standardize input data requirements.

The provisional IS Transmission Service rates will be applied to customers who purchase transmission services. Western, Basin Electric, and Heartland will take IS Transmission Service. The IS Transmission Service to the UGPR's Customers will continue to be bundled in their firm electric service under existing contracts that expire in 2020.

IS Transmission System Total Load

The IS Transmission System Total Load is the 12-cp system peak for Network IS Transmission Service plus the reserved capacity for all IS Long-Term Firm Point-to-Point Transmission Service. For the provisional rate, the IS Transmission System Total Load is estimated to be 4,605,000 kW.

Revenue Requirement for IS Transmission Service

The current rates for the IS Transmission Service are based on a revenue requirement that recovers the annual costs of Western, Basin Electric, Heartland, and approved customer facility credits associated with providing IS Transmission Service. The annual costs are offset by appropriate transmission revenue credits to avoid over recovery of costs.

Western is changing the method of developing the revenue requirement for Network, Firm Point-to-Point, and Non-Firm Point-to-Point transmission services. Western is changing the implementation of the formula rates to recover expenses and investments in transmission on a current (forward looking) rather than a lagging basis. This change will allow Western to more accurately match cost recovery with cost incurrence. To implement this change, Western will utilize estimates of the IS transmission system costs and load for the upcoming year in the formula rate recalculation. Western will true-up the estimates based on IS actual costs and actual load. Rates will continue to be recalculated every year. Revenue collected in excess of Western's, Basin Electric's, Heartland's, and entities' receiving customer facility credits actual net revenue requirements will be returned to customers through a reduction in revenue requirement in a subsequent year. Actual revenues that are less than the net revenue requirement would likewise be recovered by an increase in a subsequent year's revenue requirement. The true-up procedure ensures the IS will recover no more and no less than its actual transmission costs.

Revenue Requirement Calculation Templates

Western will initiate the use of standardized revenue requirement calculation templates by those entities submitting financial data for the annual rate recalculation to aid in the revenue requirement/rate recalculation and review processes. These revenue requirement templates will gather required financial information and data from IS partners and other entities for the calculation of revenue requirements and facility credits. Western will review requests to utilize other or modified templates for appropriateness and conduct a public process prior to granting approval for use. Western will accept use of a FERC approved template for a particular entity without conducting a public process prior to granting approval for use provided that the following conditions are met: (1) The template addresses all the transmission facilities owned by the entity; (2) the template includes a separate allocation for IS qualifying facilities; and (3) it is the latest FERC approved template for this entity.

Review of Annual Revenue Requirement and Rate Recalculation

Western will determine the IS net projected revenue requirement and load for each year in accordance with applicable IS rate schedules. Western will make the IS net projected revenue requirement available to customers including projected costs of plant in the rate base, transmission O&M expense, transmission administrative and general expense, transmission depreciation expense, load, and resulting rates incorporating any True-up Adjustment. All data will be provided in sufficient detail to identify the components of Western's net revenue requirement.

Western has conducted an annual IS rate recalculation utilizing the previous year's data with the recalculated rate effective May 1 of each year. With the implementation of the provisional formula rates resulting from this process effective on January 1, 2010, Western will conduct future rate recalculations with an effective date of January 1.

Western will provide the results of this annual rate recalculation to customers on or about September 1 of each year and will provide customers the opportunity to discuss and comment on the recalculated rates by October 31 of each year. Western will respond to customer comments prior to or at the time of the implementation of the recalculated revenue requirements and/or rates. For the provisional rates going into effect on January 1, 2010, the Annual Revenue Requirement for IS Transmission Service is $163,521,251.

Should Western find that any comment concerning the rate formula bears merit, Western reserves the right to make adjustments to the revenue requirements and/or rates consistent with proper application of the Formula Rate. Western's determination concerning the proper application of the Formula Rate will be final.

True-Up Procedures

Under the true-up procedures, any differences between estimated revenue requirements and actual revenue requirements in any given year are identified based on Revenue Requirement Templates utilizing actual financial data and actual load data for the preceding year. Revenue collected in excess of the actual net revenue requirement will be returned to customers through a reduction in revenue requirement in the subsequent year following the calculation of the true-up. Revenues that are less than the forecast net revenue requirement would likewise be recovered in the IS rates for the subsequent year.

Actual Net Revenue Requirement (calculated in accordance with Western's Rate Recalculation process) for the previous year as provided in the revenue requirement templates for Western IS partners and entities receiving revenue credits shall be compared to the projections made for the same year (True-up Year). The comparison of actual net revenue to projected net revenue determines the excess or shortfall in the projected revenue requirement used for billing purposes in the True-up Year. In addition, actual divisor loads (12-cp average) will be compared to projected divisor loads and the difference multiplied by the rate actually billed to determine any excess or shortfall in collection due to volume. The sum of the excess or shortfall due to the actual versus projected revenue requirement and the excess or shortfall due to volume shall constitute the True-up Adjustment. The True-up Adjustment and related calculations shall be posted to Western's OASIS no later than July 1 following the issuance of financial statements for the previous year. Western will provide an explanation of the True-up Adjustment in response to customer inquiries and will post on the OASIS information regarding frequently asked questions.

The Net Revenue Requirement for transmission services for the following year will be the sum of the projected revenue requirement for the following year, plus or minus the True-Up Adjustment and any other adjustments from the previous year.

Formula Rate for Network IS Transmission Service

While Western is changing the method for developing annual revenue requirements, the formula for calculating the Network Transmission Service rate is unchanged from Western's previously approved filing with the FERC. Western will use a current year formula rate which involves a change to the manner in which the inputs are developed rather than a change in the formula itself. The charge for monthly Network IS Transmission Service is the product of the network customer's load ratio share times one-twelfth (1/12) of the annual Network Transmission Revenue Requirement. The Network Transmission Revenue Requirement is the annual cost associated with providing transmission service less revenue credits for Non-Firm Transmission Service. The Network Transmission Revenue Requirement will be based on estimates for costs to provide transmission service for the up-coming year. The load ratio share is the network customer's hourly load coincident with the IS monthly Transmission System peak minus the coincident peak for all IS Firm Point-to-Point Transmission Service plus the Firm Point-to-Point reservations. The Network rate includes costs for scheduling, system control, and dispatch service needed to provide transmission service.

Formula Rate for Firm Point-to-Point IS Transmission Service

The monthly rate for Firm Point-to-Point IS Transmission Service is 1/12 the annual cost associated with providing transmission service less revenue credits for Non-Firm Transmission Service divided by the capacity reservation needed to support the average monthly IS Transmission System load. As with Network Transmission Service, Western will be using a current year formula rate which involves a change to the manner in which the inputs are developed rather than a change in the formula itself. This rate may be summarized with the following formula: ISFPTP = (Total Annual Revenue Requirement—Non Firm Revenue Credits)/12 months/ Average Transmission System Monthly Peak Load. Firm Point-to-Point Transmission Service will be offered on an up to basis at daily, weekly, monthly, and yearly rates.

Formula Rate for Non-Firm Point-to-Point Transmission

Western will not change the rate formula for Non Firm Point-to-Point Transmission Service other than utilizing cost projections as data inputs to determine the annual revenue requirement as described above. The Non Firm Point-to-Point Transmission Service rate formula remains: Monthly IS Firm Point-to-Point Transmission Service rate divided by 730 hours per month times 1000 mills per dollar.

The following table summarizes the difference between the current IS Transmission Service rates and the provisional IS Transmission Service rates. It compares the change in the projections for the 2009–2010 transmission and ancillary services study and the provisional IS Transmission Service rates for this rate adjustment based on the most recent historical data and estimated data available at the time of the initial rate proposal.

COMPARISON OF ANNUAL REVENUES

Item	Existing rate	Provisional rate	Percentage change
Annual IS Cost (Net of Revenue Credits)	$147,038,956	$154,900,362	5.35
Transmission Customer Facility Credits	8,541,224	8,620,889	0.93
Annual Revenue Requirement for IS Transmission Service	155,580,180	163,521,251	5.10
Adjustment for Prior Year	523,417	N/A	N/A
Annual Transmission Revenue Requirement	155,056,530	163,521,251	5.46

Basis for Rate Development

The current IS Network, Firm Point-to-Point and Non-Firm Point-to-Point Transmission Service formula rates are scheduled to expire on September 1, 2010. The current Network, Firm Point-to-Point and Non-Firm Point-to-Point Transmission Service formula rates do not capture new investment costs until they have been in service for up to 2 years. The proposed rates are forward looking and include estimates for investments being placed in service, annual operation and maintenance expenses, depreciation, interest, and administrative and general costs. In the past, rates were recalculated in April and were effective on May 1. The rates implemented in this process will be available for review on or about September 1 and placed into effect on January 1.

Integrated System Ancillary Services Rates Discussion

The IS will continue to offer the following six ancillary services: (1) Scheduling system control, and dispatch service; (2) reactive supply and voltage control from generation sources service; (3) regulation and frequency response service; (4) energy imbalance service; (5) spinning reserve service and (6) supplemental reserve service; and will add a seventh ancillary service; (7) generator imbalance service.

Western has already marketed the maximum practical amount of power from each of its projects, based on a reasonable level of risk, leaving little or no Federal hydroelectric power resources available for ancillary services. Changes in water conditions frequently affect the ability of the hydroelectric projects to meet obligations on a short-term basis. The unique characteristics of the hydro resource, Western's existing long-term power commitments, and the limitations of the resource due to changing water conditions limit Western's ability to provide Transmission Customers generation-related ancillary services and redispatch using Federal hydro resources. Consequently, Western will provide ancillary services by purchasing power resources whenever necessary and pass through these costs to the customer.

Formula Rate for Scheduling, System Control, and Dispatch Service

Western's annual revenue requirement for Scheduling, System Control, and Dispatch Service is determined by multiplying the portion of the Watertown Operations Office net plant, and the communications facilities net plant associated with Scheduling, System Control, and Dispatch Service by the transmission fixed charge rate. In the past, the annual revenue requirement for Scheduling, System Control, and Dispatch Service has been divided by the number of daily schedules in the calculation year. Western is changing this formula. Instead of dividing the annual revenue requirement for Scheduling, System Control, and Dispatch Service by the number of daily schedules in the calculation year, Western will divide the annual revenue requirement for Scheduling, System Control, and Dispatch Service by the number of daily tags in the calculation year. This rate and rate design is recovering only Western's revenue requirement.

Formula Rate for Reactive Supply and Voltage Control Services From Generation Sources Service

Western's current formula for Reactive Supply and Voltage Control from Generation Sources (RSVC) Service is determined by multiplying the total P–SMBP–ED generation net plant by the generation fixed charge rate. The annual cost is multiplied by the five (5) year average peak monthly percentage of Western's generation operating in a synchronous condenser mode to determine Western's reactive service revenue requirement. Western's, Basin Electric's, Heartland's, and Missouri River Energy Services' revenue requirements for RSVC Service are summed to get the total revenue requirement for this service. The RSVC Service rate is then derived by dividing the total annual revenue requirement by the load requiring RSVC Service. The annual cost is then divided by 12 months to obtain a monthly rate. In this formula, Western is only compensated for providing RSVC Service based upon the cost of Western's generation operating outside the 0.95 leading to 0.95 lagging power factor bandwidth, while Basin, Heartland, and Missouri River Energy Services are compensated based on costs for generation operating within this power factor bandwidth.

Western is changing its rate for RSVC Service by removing costs of any generation associated with operation within the bandwidth from the total revenue requirement for this service. Under Western's current rate, Western is not compensated for providing RSVC Service from its own generators operating inside the bandwidth while non-Federal generators are receiving compensation for providing RSVC Service within the bandwidth. Western believes that both Federal and non-Federal generators should be treated comparably when they provide RSVC Service within the bandwidth. Therefore, Western is discontinuing payment for all other generators providing RSVC Service within the 0.95 leading to 0.95 lagging power factor bandwidth.

Western will continue to collect its RSVC Service cost, for its generators operating within the bandwidth, in the firm power revenue requirement under the then appropriate firm power rate schedule and not from Transmission Customers under its OATT. Therefore, only Federal preference power customers will pay the RSVC costs of the Federal generators operating within the bandwidth. This change will result in transmission service customers paying for RSVC Service based only upon costs for generators operating outside the bandwidth. Excluding RSVC Service costs associated with generator operation within the bandwidth from the RSVC Service revenue requirement will require all other non-Federal generator owners to recover their RSVC Service costs, for operation within the bandwidth, elsewhere.

Western's Federal generation is required to operate in synchronous condenser mode (i.e., outside the power factor bandwidth) to maintain system voltages and meet reliability criteria and, therefore consistent with the previous practice, Western will include its costs to provide RSVC Service for Federal generators operating outside the bandwidth. Western will include costs associated with other non-Federal generators required to operate outside the power factor bandwidth to maintain system voltages and meet reliability criteria (e.g., other generators that operate as synchronous condensers, or generators that are requested by Western to operate outside the bandwidth as noted in Western's generator interconnection procedures and agreements).

The following provisional rate formula will apply: Western's total P–SMBP–ED generation net plant multiplied by the generation fixed charge rate (in percent) equals Western's annual cost. Western's annual cost is multiplied by the five (5) year average peak monthly percentage of Western's Federal synchronous condensing generation to determine Western's outside the bandwidth reactive service revenue requirement. Western's revenue requirement plus any revenue requirement or costs incurred from other non-Federal generators required by Western to operate outside the bandwidth is the total annual revenue requirement for RSVC Service. This total annual revenue requirement is then divided by the total load (kWyear) in Western's Control Areas.[3] The product is then divided by 12 months to obtain a monthly charge.

Formula Rate for Regulation and Frequency Response Service

Western will continue the current formula-based rate methodology for Regulation and Frequency Response Service as described below. Regulation and Frequency Response Service in the east side of the Control Area is provided primarily by Oahe generation and in the west side of the Control Area by Fort Peck, both of which are Corps of Engineers (Corps) facilities. The Corps generation fixed charge rate (in percent) is applied to Oahe and Fort Peck net plant investment, producing an annual Corps generation cost for the Oahe and Fort Peck power plants. This cost is divided by the capacity at the plants (937,000 kW) to derive a dollar per kilowatt amount for Oahe's and Fort Peck's installed capacity (kWYear). This dollar per kilowatt amount is then

[3] Western has retained the term ''Control Area'' in this document maintaining consistency with usage of the term in FERC's *pro forma* tariff and Western's current OATT. As defined in Western's OATT, a Control Area is: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) Match, at all times, the power output of the generators within the electric system(s) and capacity and energy purchased from entities outside the electric power system(s), with load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

applied to the capacity (in kW) of Oahe and Fort Peck generation reserved for regulation and frequency response in the Control Area. Western's annual revenue requirement for Regulation and Frequency Response Service is determined by applying the dollar per kilowatt charge to the capacity used for Regulation and Frequency Response Service plus the cost of any additional resources acquired to support regulation requirements for intermittent renewable resources serving load within Western's Control Areas. The total Regulation and Frequency Response Revenue Requirement is determined by adding Western's, Basin Electric's, and Heartland's Regulation and Frequency Response Revenue Requirements. The Regulation and Frequency Response Service charge is then determined by dividing the total revenue requirement by the total load in the Control Area (kWYear). The result is then divided by 12 months to obtain a monthly charge.

Western supports the installation of renewable sources of energy but recognizes that certain operational constraints exist in managing the significant fluctuations that are a normal part of their operation. When Western purchases power resources to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within Western's Control Areas, costs for these regulation resources will become part of Western's Regulation and Frequency Response Service charges. However, Western has marketed the maximum practical amount of power from each of its projects leaving little or no flexibility for provision of additional power services. Consequently, Western will not regulate for the difference between the output of an intermittent generator located within Western's Control Area and a delivery schedule from that generator serving load located outside of Western's Control Area. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area.

Rate for Energy Imbalance Service

Western is changing its rate for Energy Imbalance Service to be consistent with the rules promulgated by FERC to the extent that it is consistent with Western's mission and is permitted by law and regulations. Currently penalty charges apply only to energy imbalances outside a 3 percent bandwidth (+/− 1.5 percent deviation). The penalty for under deliveries outside the 3 percent bandwidth is 100 mills/kWh while over deliveries outside the bandwidth are forfeited.

Western proposes charges be modified and based on the deviation bands as follows: Deviations within +/− 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost for the month. Deviations greater than +/− 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost when energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled or 90 percent of incremental cost when energy taken by a Transmission Customer in a schedule hour is less than the scheduled amount. Deviations greater than +/− 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the incremental cost for energy taken by the Transmission Customer in a scheduled hour that is greater than the energy scheduled, or 75 percent of the incremental cost for that hour when energy taken by a Transmission Customer is less than the scheduled amount.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's OASIS *http://www.oatioasis.com/wapa/index.html* at least 30 days prior to use for determining Western's incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

Formula Rates for Operating Reserves Service—Spinning and Supplemental

Western will continue the current formula-based rate methodology for Spinning Reserve Service and Supplemental Reserve Service (Reserve Services), except that Western will substitute the reserve requirement of the current reserve sharing group of which Western and the IS Partners are members or will substitute Western's and the IS Partners' own operating reserve requirement for that of the Mid-Continent Area Power Pool (MAPP) requirement.

Western's annual cost of generation for Reserve Services is determined by multiplying the generation fixed charge rate by the P-SMBP–ED generation net plant investment. The cost/kWyear is determined by dividing the annual cost of generation by the plant capacity. The capacity used for Reserve Services is determined by multiplying the peak IS load by either the operating reserve requirement of the current reserve sharing group of which Western and the IS Partners are members or their own operating reserve requirement. The cost/kWyear is multiplied by the capacity used for Reserve Services to obtain the annual revenue requirement. The annual revenue requirement for Reserve Services is divided by Western's peak transmission load to calculate the annual rate. The annual rate is then divided by 12 months to obtain a monthly rate. This rate design recovers only Western's revenue requirement associated with Reserve Services.

Western has no long-term reserves available beyond its own internal requirements. At a customer's request, Western will acquire needed resources and pass the costs on to the requesting customer. The customer is responsible to provide the transmission to deliver these reserves.

Rate for Generator Imbalance Service

Western is adding a Generator Imbalance Service rate under a new Rate Schedule, UGP–AS7, to be consistent with rules promulgated by FERC to the extent consistent with Western's mission and permitted by law and regulations. However, if Western does not also implement a Generator Imbalance Service in a revised OATT, this rate will not be utilized.

Generator Imbalance Service is provided when a difference occurs between the output of a generator located within the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. Western will offer this service, to the extent that it is feasible to do so from its own resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation.

Western may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule UGP–AS7 or hourly energy imbalances under Rate Schedule UGP–AS4 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

Western bases the rate on deviation bands as follows: Deviations within +/− 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost. Deviations greater than +/− 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month. When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 110 percent of incremental cost. When energy delivered from the generation resource is greater than the scheduled amount, the credit is 90 percent of the incremental cost. Deviations greater than +/− 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of Western's incremental cost when energy delivered in a schedule hour is less than the energy scheduled or 75 percent of Western's daily incremental cost for that hour when energy delivered from the generation resource is greater than the scheduled amount. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW.

Deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's OASIS *http://www.oatioasis.com/wapa/index.html* at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

The following table summarizes the difference in calculations between the current IS Ancillary Service rates and the provisional IS Ancillary Service rates. It compares the change in the average annual projections used in the 2009–2010 transmission and ancillary services study and the provisional IS Transmission and Ancillary Service rates for this rate adjustment based on the most recent historical and estimated data available at the time of the rate estimate.

COMPARISON OF ANCILLARY SERVICE RATES

Item	Unit	Existing rate	Provisional rate	Percentage change
Scheduling, System Control, and Dispatch Service.	Schedule/Tag	$44.59/Schedule/day	$44.59/Tag/day	0.00
Reactive Supply and Voltage Control.	kWmonth	0.09	0.05	−44.44
Regulation and Frequency Response.	kWmonth	0.05	0.05	0.00
Energy Imbalance	Deviation Bands as Described	N/A	N/A	N/A
Reserves	kWmonth	0.14	0.18	28.57
Generator Imbalance	Deviation Bands as Described	N/A	N/A	N/A

Basis for Rate Development

The current IS Ancillary Service formula rates are scheduled to expire on September 30, 2010. The current IS Ancillary Service formula rates do not capture new investments costs until they have been in service for up to 2 years. In the past, rates were recalculated in April and were effective on May 1. The rates implemented in this process will be available for review on or about September 1 and placed into effect on January 1. In addition the provisional rates alter the deviation bands for energy imbalance and define incremental costs for energy imbalance based on an index price. A similar service for generator imbalance is introduced. The rate for RSVC Service will no longer include the costs of any generation associated with operation within the 0.95 leading and 0.95 lagging power factor bandwidth from the total revenue requirement for this service. Rates for Spinning Reserve Service and Supplemental Reserve Service (Reserve Services) will be based on the reserve requirement of the current reserve sharing group of which Western and the IS Partners are members or will substitute Western's and the IS Partners' own operating reserve requirement.

Comments

The comments and responses below regarding the transmission and ancillary services rates are paraphrased for brevity when not affecting the meaning of the statement(s). Direct quotes from oral or written comments are used for clarification when necessary.

1. *Comment:* Western received both oral and written comments that the need for an Energy Imbalance Rate Schedule would be eliminated if Western participated in an organized market such as the Midwest Independent System Operator (MISO) market.

Response: This comment is not directly related to the proposed rate action and is outside the scope of this rate process. However, Western has and will continue to evaluate this and other options based on the cost and benefit to Western's customers.

2. *Comment:* Western received comments that introducing an Energy Imbalance Service and a Generator Imbalance Service to mitigate imbalances create an arbitrarily punitive structure for deviations while at the same time ignoring whether or not one party's deviation may actually off-set another party's deviation and eliminate the net deviation.

Response: Western disagrees that introducing the Energy Imbalance and Generator Imbalance Services creates an arbitrarily punitive structure for deviations. In establishing its Energy Imbalance and Generator Imbalance Services, Western is implementing the deviation structure as delineated in the FERC's Order 890 and Orders 890A through C. It is Western's intent that imbalance charges should provide appropriate incentives to keep schedules accurate and that the tiered structure recognizes the link between escalating deviations and potential reliability impacts on the system. Western believes that to net one party's deviation against another party's deviation, absent formal agreements among the parties, would not necessarily provide an appropriate incentive for either party to accurately schedule. Western recognizes that, other than the first deviation band, there is no netting of energy; however, there is financial netting in the financial settlement process.

3. *Comment:* Western received a comment advocating that the Imbalance Services be applicable to all network customers independent of their respective marketing arrangements.

Response: Western disagrees that Imbalance Services be applicable to all transmission customers regardless of their respective marketing arrangements. If a group of transmission customers create a formal marketing arrangement between them and agree to share imbalances (*i.e.,* essentially self supplying) Western will allow that group of transmission customers to be treated as a single entity in regard to Western's application of imbalance charges. Western believes that this is reasonable if the group of transmission customers has formal arrangements to provide imbalance service to each other. To the extent that the overall group is assigned an imbalance charge by Western, the group would assign the responsibility for such charges within the group based upon their formal marketing arrangements. Western would assign imbalance charges to the group in a similar manner that it assigns imbalance charges to an individual transmission customer that relies only on the balancing authority to make up for its imbalances. Western will allow any group of transmission customers to utilize formal marketing arrangements to meet its imbalance obligations on a comparable manner.

4. *Comment:* Western received oral and written comments that if the Integrated System proceeds with implementation of the Energy Imbalance and Generator Imbalance schedules, that it should introduce steps to offset deviations from the individual network customers and then consider the net impact to the Control Area.

Response: Western disagrees with the comment that it should offset imbalances between individual network customers without any formal arrangements between those transmission customers. To do so would allow individual transmission customers to improperly take delivery from other transmission customers without any arrangements or agreement by other transmission customers to allow such deliveries. Western's proposed imbalance schedules are intended to incent individual transmission customers or formal groups of transmission customers to meet their individual or group responsibilities to accurately schedule and not rely on the control area or other transmission customers with which it has no arrangements. Western believes that it is necessary to net the various transmission deliveries of each individual transmission customer or formal group of transmission customers (*e.g.,* multiple Point-to-Point deliveries) to assign imbalance charges to that individual customer or formal group of transmission customers based upon their overall impact to Western's control area(s).

5. *Comment:* Western received a comment that revenue generated from the Energy and Generator Imbalance schedules should credit Western's transmission customers on a load ratio share basis so as not to incent Western from continuing with this service in lieu of participating in an organized market such as MISO.

Response: Western's Energy and Generator Imbalance revenue in excess of its incremental costs will reduce future annual transmission revenue requirements. Participation in an organized market such as MISO is not directly related to the proposed rate action and is outside the scope of this rate process.

6. *Comment:* Western received both oral and written comments concerning utilizing price indexes in its Energy and Generator Imbalance rate schedules. Comments advocated utilizing a single index for each of the eastern and western interconnections rather than the higher of the two. Barring using a price index for each interconnection, commenter advocated use of a ratio of index prices and provided suggestions for ratio formula. Also received was a written suggestion that Western utilize hourly pricing instead of the highest daily price as a method to allocate costs. Commenter also questioned what the two index prices will be based on, why the highest daily price is used for the +/−7.5% band, and if the index prices are negative if Western is prepared to credit the customer for the deviation.

Response: Western disagrees with the comments received that it should utilize individual indexes or a weighted index based upon its eastern and western interconnection control areas based upon the argument that its transmission customers may only be participating in one market (east or west). Western operates its combined system as one system, and utilizes both east and west resources to provide for ancillary services across its entire system under its tariff. Therefore, if a transmission customer creates an imbalance due to its operations in the east market, Western may need to utilize resources from its west side to provide for the imbalance service required by the transmission customer. Western does, however, agree with the suggestion that Western utilize hourly pricing instead of the highest daily price as a method to allocate costs in the +/− 7.5% band. Western also clarifies that it will limit the selected index to a minimum of zero in the case where index prices may become negative and does not expect that will be an issue based upon its proposal to utilize the higher of the eastern and western interconnection price index.

7. *Comment:* Western received two comments expressing concern for the method of measuring the energy taken on an hourly basis and how supplemental or co-supplier energy imbalance would be determined for customers with a fixed Contract Rate of Delivery and supplemental supplier(s).

Response: Western thanks commenter for addressing these issues. Western recognizes that these issues will need to be resolved prior to charging for Energy or Generator Imbalance Service. Consequently, Western will delay charging until such time as these issues can be resolved. Western will collaborate closely with its customers affected by these issues and resolve them. These issues are billing related rather than rate related; therefore, the rate will become effective as scheduled. However, Western will not implement these schedules until the billing issues are resolved. Upon completing arrangements with its customers concerning the method(s) to be used in calculating energy and generator imbalance charges, Western will post notice on its OASIS Web site providing 30 days notice to customers prior to initiating charging/billing for Energy or Generator Imbalance Service. Similar to the process for allowing review of annual revenue data submittals discussed below, Western is committed to providing customers with a forum to address implementation issues related to Energy and Generator Imbalance schedules that are outside the rate schedules themselves.

8. *Comment:* A comment was received by Western questioning the point in Energy Imbalance and Generator Imbalance Service where charges were rounded and if the rounding was done for each hour.

Response: Western will round energy and generator imbalance calculations to the nearest cent on an hourly basis with the exception of the first deviation tier. In the first deviation band, deviations will be netted and settled financially at the end of the month.

9. *Comment:* A comment was received by Western expressing concern for the billing process for energy and generator imbalance calculations.

Response: Western anticipates billing procedures for Energy Imbalance and Generator Imbalance will be similar to billing for any other service and that customer bills will provide sufficient data to verify charges. Western's policy for correction of billing errors will apply for these charges as it does for all other services.

10. *Comment:* Western received a comment expressing concern that implementing Generator Imbalance Service would further deter development of renewable generation such as wind fueled generation.

Response: This comment is not directly related to the proposed rate action and is outside the scope of this rate process.

11. *Comment:* Western received oral and written comments requesting Western delay implementation of Rate Schedule UGP–AS2 pending provision of additional information concerning compensation of generators requested by Western to operate outside the identified bandwidth in providing Reactive Supply and Voltage Support.

Response: Western disagrees that it should delay the implementation of Rate Schedule UGP–AS2 pending providing additional information concerning its procedures for compensation of generators for providing reactive support outside the bandwidth identified in its Large and Small Generator Interconnection Procedures (LGIP/SGIP) and Agreements (LGIA/SGIA). Western has included such provisions and currently has a requirement to provide compensation for requesting an interconnection customer to operate its generation outside the standard power factor bandwidth indentified in its tariff. For example, Western will provide compensation to a large generator as outlined in its LGIA Sections 9.6.3 and 11.6. Western will request the interconnection customer to identify its appropriate costs or rate schedule for it providing reactive support to the transmission provider and will compensate the interconnection customer based upon the agreed upon methodology between the parties.

12. *Comment:* Western received oral and written comments recommending that the IS accept any annual transmission revenue requirement template specifically approved by the FERC for an individual party without approval via a public process.

Response: Western's UGPR agrees with the commenter that a party should be able to utilize a FERC approved template for a particular party, provided that the following conditions are met: (1) the template addresses all the transmission facilities owned by the party; (2) the template includes a separate allocation for IS qualifying facilities; and (3) it is the latest FERC approved template for this party.

13. *Comment:* A comment received by Western expressed understanding for the implementation of the forward looking rates with annual true-up in an era of tremendous transmission expansions.

Response: Western appreciates commenter's understanding of Western's need and efforts to match cost recovery to cost incurrence through the forward looking rate with annual true-up.

14. *Comment:* Western received a comment suggesting a forum for customers to provide comments and ask questions concerning rate adjustments needed for prior year over/under collections.

Response: Western recognizes that an annual customer meeting or forum to discuss application of the true-up of the revenue requirement(s) based on actual, audited financial data is necessary and beneficial. Accordingly, Western has committed to making data for annual rate recalculations and true-ups of prior year over/under collections available to customers on or about September 1 of each year and to providing a forum during which customers can ask questions concerning the data utilized in rate recalculations and the annual revenue requirement true-up calculation prior to October 31.

15. *Comment:* Western received a comment concerning revenue requirement review for reasonableness and providing answers to customer questions.

Response: Western agrees with commenter concerning the need to review revenue requirements for reasonableness. Western has committed to making data for annual rate recalculations and true-ups of prior year over/under collections available to customers on or about September 1 of each year and to providing a forum during which customers can ask questions concerning the data utilized in rate recalculations and the annual revenue requirement true-up calculation prior to October 31.

16. *Comment:* A comment was received that Western should add a statement to its rate schedules that use of a standard template or formula does not remove the obligation of transmission owners to substantiate accuracy of financial data with audited financial statements, FERC Form 1, or other publically available information.

Response: Western agrees that accurate financial data is necessary and will require entities submitting financial data in support of revenue requirements or facility credits to provide appropriate substantiation.

17. *Comment:* Western received a comment advocating that an interest rate apply to any over collection of funds.

Response: Every effort will be made to accurately forecast costs and load in an effort to minimize any over or under collection of annual revenue requirements. Western intends to closely monitor collections and will make or insist upon appropriate revenue requirement adjustments. Western does not believe assessing interest on over collections while not assessing interest on under collections to be equitable.

18. *Comment:* Western received a comment that Western and other IS owners should continue to provide detailed facility information on existing and new facilities included in transmission rates similar to what is done today.

Response: Western agrees with this comment and will continue to provide facility information.

Penalty Rate for Unreserved Use of Transmission Service

Unreserved Use of Transmission Service is provided when a Transmission Customer uses transmission service that it has not reserved or uses transmission service in excess of its reserved capacity. A Transmission Customer that has not secured reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed penalties for Unreserved Use of Transmission Service under new Rate Schedule UGP–TSP1. Western has not concluded modifications to its OATT required as a result of FERC Order 890. Consequently, charges for unreserved use will not be implemented until such time as Western's revised OATT is effective. However, by establishing its Penalty Rate for Unreserved Use of Transmission Service in this process, Western will avoid the need and cost for a separate public process to develop this rate at a later date. Western will provide written notification to its Transmission Customers prior to implementing the penalty rate for unreserved use and will also post a notification on its OASIS web site indicating the implementation of Transmission Service Penalty Rate for Unreserved Use.

The penalty charge for a Transmission Customer that engages in unreserved use is 200 percent of Western's approved transmission service rate for point-to-point transmission service assessed as follows: the Unreserved Use Penalty for a single hour of unreserved use will be based upon the rate for daily firm point-to-point service. The Unreserved Use Penalty for more than one assessment for a given duration (*e.g.,* daily) will increase to the next longest duration (*e.g.,* weekly). The Unreserved Use Penalty charge for multiple instances of unreserved use (for example, more than 1 hour) within a day will be based on the rate for daily firm point-to-point service. The penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service. The penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month is based on the charge for monthly firm point-to-point service.

A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all Ancillary Services identified in Western's OATT that were provided by Western and associated with the unreserved service on the IS system. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. Unreserved Use Penalties collected over and above the base point-to-point transmission service charge will be credited against the IS Annual Transmission Revenue Requirement (ATRR).

Basis for Rate Development

The provisional penalty rate provides payment for transmission and ancillary services at the current rates for these services thereby contributing to the revenues required to pay all annual costs, including interest, and repay investments within the allowable periods. The penalty portion of the rate will be returned to customers via credits to future transmission revenue requirement.

Comments

The comments and responses below regarding the Transmission Service Penalty Rate for Unreserved Use rate are paraphrased for brevity when not affecting the meaning of the statement(s). Direct quotes from oral or written comments are used for clarification when necessary.

1. *Comment:* Western received a comment that Western should provide details to several issues associated with the determination of unreserved use and billing for unreserved use. Specifically, commenter states that while Western provides a general description of what it will consider unreserved use, it does not furnish information about the methods that will be utilized to determine that unreserved use has occurred and that Western should explain how it will identify that the unreserved use is a result of exceeding reserved capacity rather than loop flows due to system conditions. Commenter continues to express the desire to have the specific methods for determining unreserved use identified ahead of time so that all parties know what to expect and can plan accordingly. Commenter further asks that Western develop a method and make that method for determining which flows are from insufficient capacity and which are loop flows publicly available.

Response: Western disagrees that it is necessary to identify in advance all specific methods for determining unreserved use but intends to provide such detailed information to any party that it proposes to charge under this rate. Western has indicated that it does not charge for loop flow but does expect its neighboring transmission providers to have adequate transmission capacity on its own system to provide the transmission service that it provides without improperly using Western's transmission system. The determination of adequate transmission capability likely needs to be determined on a case-by-case basis. To the extent that a party disagrees with Western's specific methodologies to base its unreserved use charge, such party has recourses outlined in Western's tariff to dispute such charge, including ultimately seeking feedback from the Federal Energy Regulatory Commission.

2. *Comment:* Western received a comment that Western should explain how the method of determining whether insufficient capacity exists is consistent with the Congestion Management Process as Western takes Interconnected Operations and Congestion Management Service under Part II of Module F of the Midwest ISO Tariff. Commenter requests Western commit that any process it develops will not be in conflict with the Congestion Management Process.

Response: Western has previously filed comments with the Commission noting that its charge for transmission service based upon a party not having sufficient transmission capacity to meet its obligations without utilizing Western's transmission system is not in conflict with its Seams agreement with the Midwest ISO. Western's Seams agreement with the Midwest ISO does not provide for uncompensated use of each other's system and specifically notes that each party to that agreement will respect their own transmission capability in providing transmission service under their separate tariffs. Western's current implementation and proposed changes to its implementation of unreserved use charges will be consistent with any provisions of Seams agreements that it enters into with its neighboring interconnected transmission providers, including the Midwest ISO.

3. *Comment:* Western received a comment that the **Federal Register** notice lacks detail regarding who will be billed for unreserved use penalty charges and asks if Western intends to send bills monthly and which entities will be billed.

Response: Western will bill unreserved use (including the newly proposed penalty charge) to the party that utilizes Western transmission system without making proper arrangements for the transmission service that it is taking. Western bills on a monthly basis; however, to the extent that Western determines that an entity is improperly taking transmission service without reserving such, Western may contact such entity prior to the normal monthly billing cycle to notify such entity that it intends to send that party a bill for service. The appropriate party to be billed will be determined on a case-by-case basis.

4. *Comment:* Western received a comment requesting that commenter be informed of the FERC actions concerning the unreserved use rate.

Response: Western will post FERC actions on its web sites at *http://www.wapa.gov/ugp/* and *http://www.oatioasis.com/wapa/index.html.*

Availability of Information

Information about this rate adjustment, including studies, brochures, comments, letters, memorandums, and other supporting material made or kept by Western, used to develop the provisional rates, is available for public review in the Upper Great Plans Regional Office, 2900 4th Avenue North, Billings, Montana.

Ratemaking Procedure Requirements

Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321–4347); Council on Environmental Quality Regulations (40 CFR parts 1500–1508); and DOE NEPA Regulations (10 CFR part 1021), Western has determined that this action is categorically excluded from preparing an environmental assessment or an environmental impact statement.

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Submission to the Federal Energy Regulatory Commission

The provisional rates herein confirmed, approved, and placed into effect, together with supporting documents, will be submitted to FERC for confirmation and final approval.

Order

In view of the foregoing and under the authority delegated to me, I confirm and approve on an interim basis, effective January 1, 2010, rates for the IS Transmission and Ancillary Services under Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–AS7 and UGP–TSP1. The rate schedules shall remain in effect on an interim basis, pending FERC's confirmation and approval of them or substitute rates on a final basis through December 31, 2014.

Daniel B. Poneman

Deputy Secretary

Rate Schedule UGP–NT1

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Annual Transmission Revenue Requirement for Network Integration Transmission Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

The Transmission Customer shall compensate the Upper Great Plains Region (UGPR) each month for Network Transmission Service under the applicable Network Integration Transmission Service Agreement and annual revenue requirement outlined below. The formula for the annual revenue requirement used to calculate the charges for this service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

UGPR may modify the charges for Network Integration Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Network Integration Transmission Service shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. UGPR shall charge the Transmission Customer under the revenue requirement then in effect.

Formula Rate

$$\text{Monthly Charge} = \frac{\text{Transmission Customer's Load-Ratio Share} \times \text{Annual Revenue Requirement for IS Transmission Service}}{12 \text{ months}}$$

Annual Revenue Requirement

A recalculated annual revenue requirement will go into effect every January 1 based on updated financial data. UGPR will notify the Transmission Customer annually of the recalculated annual revenue requirement on or before September 1.

Rate Schedule UGP–FPT1

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

The Transmission Customer shall compensate the Upper Great Plains Region (UGPR) each month for Reserved Capacity under the applicable Firm Point-to-Point Transmission Service Agreement and rates outlined below. The formula rates used to calculate the charges for service under this schedule were developed and may be modified under applicable Federal laws, regulations, and policies.

UGPR may modify the rate for Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the rate for Firm Point-to-Point Transmission Service shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. UGPR shall charge the Transmission Customer under the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) Any offer of a discount made by UGPR must be announced to all eligible Transmission Customers solely by posting on the Open Access Same-Time Information System (OASIS); (2) any Transmission Customer-initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, UGPR must offer the same discounted transmission service rate for the same time period to all eligible Transmission Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Formula Rate

$$\text{Firm Point-to-Point Transmission Rate} = \frac{\text{Annual IS Transmission Service Revenue Requirement}}{\text{IS Transmission System Total Load}}$$

A recalculated rate will go into effect every January 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before September 1.

Rate Schedule UGP–NFPT1

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Non-Firm Point-To-Point Transmission Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

The Transmission Customer shall compensate Upper Great Plains Region (UGPR) for Non-Firm Point-to-Point Transmission Service under the applicable Non-Firm Point-to-Point Transmission Service Agreement and rate outlined below. The formula rates used to calculate the charges for service under this schedule were developed and may be modified under applicable Federal laws, regulations, and policies.

UGPR may modify the rate for Non-Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the rate for Non-Firm Point-to-Point Transmission Service shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. UGPR shall charge the Transmission Customer under the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) Any offer of a discount made by UGPR must be announced to all eligible Transmission Customers solely by posting on the Open Access Same-Time Information System (OASIS); (2) any Transmission Customer-initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, UGPR must offer the same discounted transmission service rate for the same time period to all eligible Transmission Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Formula Rate

$$\text{Maximum Non-Firm Point-to-Point} = \frac{\text{Firm Point-to-Point Transmission Rate} \times \text{1000 Mills/\$}}{\text{730 hours/month}}$$

Rate

A recalculated rate will go into effect every January 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before September 1.

Rate Schedule UGP–AS1

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Scheduling, System Control, and Dispatch Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

This service is required to schedule the movement of power through, out of, within, or into the Western Area Upper Great Plains Balancing Authorities (WAUE and WAUW). The charges for Scheduling, System Control, and Dispatch Service are to be based on the rate outlined below. The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

The rate will be applied to all schedules for IS non-Transmission Customers. Western will accept any reasonable number of schedule changes over the course of the day without any additional charge.

The charges for Scheduling, System Control, and Dispatch Service may be modified upon written notice to the customer. Any change to the charges for the Scheduling, System Control, and Dispatch Service shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement.

Upper Great Plains Region (UGPR) shall charge the non-Transmission Customer under the rate then in effect.

Formula Rate

$$\text{Rate per Tag per Day} = \frac{\text{Annual Revenue Requirement for Scheduling, System Control, and Dispatch Service}}{\text{Number of Daily Tags per Year}}$$

Rate

A recalculated rate will go into effect every January 1 based on the above formula and data. UGPR will notify the customer annually of the recalculated rate on or before September 1.

Rate Schedule UGP–AS2

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Reactive Supply and Voltage Control From Generation Sources Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

To maintain transmission voltages on all transmission facilities within acceptable limits, generation facilities under the control of the Western Area Upper Great Plains balancing authorities (WAUE and WAUW) are operated to produce or absorb reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (Reactive Service) must be provided for each transaction on the transmission facilities. The amount of Reactive Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the Reactive Service necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Western.

The Transmission Customer must purchase this service from the Transmission Provider. The charges for such service will be based upon the rate outlined below. The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

The charges for Reactive Service may be modified upon written notice to the Transmission Customer. Any change to the charges for Reactive Service shall be as set forth in a revision to this rate schedule developed to applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. Upper Great Plains Region (UGPR) shall charge the Transmission Customer under the rate then in effect.

Any waiver of this charge or any crediting arrangements for Reactive Service must be documented in the Transmission Customer's Service Agreement.

Formula Rate

$$\text{Reactive Service Rate} = \frac{\text{Annual Revenue Requirement for VAR Support}}{\text{Load Requiring VAR Support}}$$

Rate

A recalculated rate will go into effect every January 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before September 1.

Rate Schedule UGP–AS3

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Regulation And Frequency Response Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources, generation, and interchange with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hz). Regulation is accomplished by committing on-line generation whose output is raised or lowered, predominantly through the use of automatic generating control equipment, as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Western Area Upper Great Plains balancing authorities (WAUE and WAUW) operator. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements to satisfy its Regulation obligation. The charges for Regulation are outlined below. The amount of Regulation will be set forth in the applicable Transmission Customer's Service Agreement.

Western supports the installation of renewable sources of energy but recognizes that certain operational constraints exist in managing the significant fluctuations that are a normal part of their operation. When Western purchases power resources to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within Western's Control Areas, costs for these regulation resources will become part of Western's Regulation and Frequency Response Service charges. However, Western has marketed the maximum practical amount of power from each of its projects leaving little or no flexibility for provision of additional power services. Consequently, Western will not regulate for the difference between the output of an intermittent generator located within Western's Control Area and a delivery schedule from that generator serving load located outside of Western's Control Area. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area.

An intermittent resource, for the limited purpose of these Rate Schedules, is an electric generator that is not dispatchable and cannot store its fuel source and, therefore, cannot respond to changes in demand or respond to transmission security constraints.

The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

Charges for Regulation may be modified upon written notice to the Transmission Customer. Any change to the Regulation charges shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. The Upper Great Plains Region (UGPR) shall charge the Transmission Customer under the rate then in effect.

Transmission Customers will not be charged for this service if they receive Regulation from another source, or self-supply it for their own load. Any waiver of this charge or any crediting arrangement for Regulation must be documented in the Transmission Customer's Service Agreement.

Formula Rate

$$\text{Regulation Rate} = \frac{\text{Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Rate

A recalculated rate will go into effect every January 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before September 1.

If resources are not available from a Western resource, the UGPR will offer to purchase the Regulation and pass through the costs, plus an amount for administration, to the Transmission Customer.

Rate Schedule UGP–AS4

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Energy Imbalance Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

Energy Imbalance Service is provided when a difference occurs between scheduled and actual delivery of energy to a load located within Western's Control Areas over a single hour. The Transmission Customer must either obtain this service from Western or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation.

Western may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule UG–AS4 or hourly generator imbalances under Rate Schedule UGP–AS7 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

The charges for Energy Imbalance Service may be modified upon written notice to the Transmission Customer. Any change to the charges for Energy Imbalance shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. Upper Great Plains Region (UGPR) shall charge the Transmission Customer under the rate then in effect.

Formula Rate

For deviations within +/− 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost.

Deviations greater than +/− 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month. When energy taken in a schedule hour is greater than the energy scheduled, the charge is 110 percent of incremental cost. When energy taken is less than the scheduled amount, the credit is 90 percent of the incremental cost.

Deviations greater than +/− 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of Western's incremental cost when energy taken in a schedule hour is greater than the energy scheduled or 75 percent of Western's incremental cost when energy taken by a Transmission Customer is less than the scheduled amount.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's OASIS *http://www.oatioasis.com/wapa/index.html* at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

Rate

The pricing and penalty for deviations in the above deviation bandwidths is as specified above.

Rate Schedule UGP–AS5

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Operating Reserve—Spinning Reserve Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

Spinning Reserve Service (Reserves) is needed to serve load immediately in the event of a system contingency. Reserves may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are outlined below. The amount of Reserves will be set forth in the applicable Transmission Customer's Service Agreement.

The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

The charges for Reserves may be modified upon written notice to the Transmission Customer. Any change to the charges for Reserves shall be as set forth in a revision to this rate schedule developed pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. Upper Great Plains Region (UGPR) shall charge the Transmission Customer under the rate then in effect.

Formula Rate

$$\text{Reserves Rate} = \frac{\text{Annual Revenue Requirement for Reserves}}{\text{Load Requiring Reserves}}$$

Rate

A recalculated rate will go into effect every January 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before September 1.

If resources are not available from a Western resource, UGPR will offer to purchase the Reserves and pass through the costs, plus an amount for administration, to the Transmission Customer.

In the event that Reserves are called upon for emergency use, UGPR will assess a charge for energy used at the prevailing market energy rate in the region. The Transmission Customer would be responsible for providing transmission service to get the Reserves to its destination.

Rate Schedule UGP–AS6

January 1, 2010

Supersedes 2005 Schedule

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Operating Reserve—Supplemental Reserve Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

Supplemental Reserve Service (Reserves) is needed to serve load in the event of a system contingency: however, it is not available immediately to serve load but rather within a short period of time. Reserves may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are outlined below. The amount of Reserves will be set forth in the applicable Transmission Customer's Service Agreement.

The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

The charges for Reserves may be modified upon written notice to the Transmission Customer. Any change to the charges for Reserves shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. Upper Great Plains Region (UGPR) shall charge the Transmission Customer under the rate then in effect.

Formula Rate

$$\text{Reserves Rate} = \frac{\text{Annual Revenue Requirement for Reserves}}{\text{Load Requiring Reserves}}$$

Rate

A recalculated rate will go into effect every January 1 based on the above formula and updated financial and load data. The UGPR will notify the Transmission Customer annually of the recalculated rate on or before September 1.

If resources are not available from a Western resource, UGPR will offer to purchase the Reserves and pass through the costs, plus an amount for administration, to the Transmission Customer.

In the event Reserves are called upon for Emergency Energy, UGPR will assess a charge for energy used at the prevailing market energy rate in the region. The Transmission Customer would be responsible for providing transmission service to get the Reserves to its destination.

Rate Schedule UGP–AS7

January 1, 2010

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Generator Imbalance Service

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule. Western will not charge for Generator Imbalance Service until Western's OATT is revised to provide for Generator Imbalance Service.

Applicable

Generator Imbalance Service is provided when a difference occurs between the output of a generator located within the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. Western will offer this service, to the extent that it is feasible to do so from its own resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. Western may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule UG–AS7 or hourly energy imbalances under Rate Schedule UGP–AS4 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area.

An intermittent resource, for the limited purpose of these Rate Schedules, is an electric generator that is not dispatchable and cannot store its fuel source and, therefore, cannot respond to changes in demand or respond to transmission security constraints.

The formula rate used to calculate the charges for service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

The charges for Generator Imbalance Service may be modified upon written notice to the Transmission Customer. Any change to the charges for Generator Imbalance shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. Upper Great Plains Region (UGPR) shall charge the Transmission Customer under the rate then in effect.

Formula Rate

Western bases the rate on deviation bands as follows: deviations within +/− 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost. Deviations greater than +/− 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month. When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 110 percent of incremental cost. When energy delivered from the generation resource is greater than the scheduled amount, the credit is 90 percent of the incremental cost. Deviations greater than +/− 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of Western's highest incremental cost for the day when energy delivered in a schedule hour is less than the energy scheduled or 75 percent of Western's lowest daily incremental cost when energy delivered from the generation resource is greater than the scheduled amount. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of these schedules, is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to transmission security constraints.

Deviations from scheduled transactions responding to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's OASIS *http://www.oatioasis.com/wapa/index.html* at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

Rate

The pricing and penalty for deviations in the above deviation bandwidths is as specified above.

Rate Schedule UGP–TSP1

January 1, 2010

United States Department of Energy Western Area Power Administration

Upper Great Plains Region Integrated System

Transmission Service Penalty Rate for Unreserved Use

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

The Transmission Customer shall compensate the Upper Great Plains Region (UGPR) each month for Unreserved Use of Transmission Service under the applicable Transmission Service rates as outlined below. The formula for the transmission service rate used to calculate the charges for this service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

UGPR may modify the charges for Unreserved Use of Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Unreserved Use of Transmission Service shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. UGPR shall charge the Transmission Customer under the applicable transmission service rate then in effect.

Penalty Rate

Unreserved Use of Transmission Service is provided when a Transmission Customer uses transmission service that it has not reserved or uses transmission service in excess of its reserved capacity. A Transmission Customer that has not secured reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed Unreserved Use Penalties under new Rate Schedule UGP–TSP1. Charges for Unreserved Use will be implemented when Western's revised OATT becomes effective.

Western will provide written notification to its Transmission Customers prior to implementing the Penalty Rate for Unreserved Use and will also post a notification on its OASIS web site indicating the implementation of Transmission Service Penalty Rate for Unreserved Use.

The penalty charge for a Transmission Customer that engages in Unreserved Use is 200 percent of Western's approved transmission service rate for point-to-point transmission service assessed as follows: The Unreserved Use Penalty for a single hour of unreserved use will be based upon the rate for daily firm point-to-point service. The Unreserved Use Penalty for more than one assessment for a given duration (*e.g.,* daily) will increase to the next longest duration (*e.g.,* weekly). The Unreserved Use Penalty charge for multiple instances of unreserved use (for example, more than 1 hour) within a day will be based on the rate for daily firm point-to-point service. The penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service. The penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month is based on the charge for monthly firm point-to-point service.

A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all Ancillary Services identified in Western's OATT that were provided by Western and associated with the unreserved service on the IS system. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used, but did not reserve.

Rate

The rate for Unreserved Use of Transmission Service is 200 percent of the approved transmission service rate for point-to-point transmission service assessed as described above.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM01–5–000]

Electronic Tariff Filings; Notice of Revised Implementation Guide for Electronic Filing

December 18, 2009.

In Order No. 714,[1] the Commission adopted regulations requiring tariff and tariff related filings to be made electronically starting April 1, 2010. Instructions on how to assemble an electronic filing are provided in *Implementation Guide for Electronic Filing of Parts 35, 154, 284, 300, and 341 Tariff Filings*, located at *http://www.ferc.gov/docs-filing/etariff.asp*.

Take notice that the *Implementation Guide* has been revised as follows (changes are marked by redline in the document):

1. The date to be used by filers that are not proposing a specific effective date has been changed from 12/31/9999 to 12/31/9998 due to Commission software constraints.

2. The Implementation Guide as been revised to clarify the usage of the "Withdraw Type of Filing Category" and the "Withdraw Record Change Type".

a. The description of the "Withdraw Type of Filing" category has been modified to reflect §§ 35.17(a) and 154.205(a) of the Commission's regulations, as adopted in Order No. 714. The revision clarifies that the Type of Filing category of "Withdraw" is the equivalent of a request to withdraw the complete associated tariff filing, not individual components of thereof.

b. The description of the "Withdraw Record Change Type" has been modified to reflect the ability to withdraw a specific tariff record without withdrawing the entire filing.

3. Discussion of the Company Identifier and password have been coordinated with the October 23, 2009 Notice regarding Company Registration and related *Instructions for Company Registration.* These instructions are located at *http://www.ferc.gov/docs-filing/company-reg.asp.* The revisions reflect the October 23, 2009 Notice's implementation of Company Identifiers and passwords, and the treatment of the Company Identifiers as public information.

For more information, please contact Keith Pierce, Office of Energy Market Regulation at (202) 502–8525 for technical information, or Anthony Barracchini, Office of the Executive Director, (202) 502–8920 for software information, or send an e-mail to *ETariff@ferc.gov*.

Kimberly D. Bose,

Secretary.

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[1] *Electronic Tariff Filings,* Order No. 714, 73 FR 57,515 (Oct. 3, 2008), 124 FERC ¶ 61,270, FERC Stats. & Regs [Regulations Preambles] ¶ 31,276 (2008) (Sept. 19, 2008).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of FERC Staff Attendance at Southwest Power Pool Regional State Committee Meeting and Southwest Power Pool Board of Directors Meeting

December 22, 2009.

The Federal Energy Regulatory Commission hereby gives notice that members of its staff may attend the meetings of the Southwest Power Pool (SPP) Regional State Committee, and SPP Board of Directors, as noted below. Their attendance is part of the Commission's ongoing outreach efforts.

SPP Regional State Committee Meeting

January 25, 2010 (1 p.m.–5 p.m. CST), Sheraton New Orleans Hotel, 500 Canal Street, New Orleans, LA 70130, 504–525–2500.

SPP Board of Directors Meeting

January 26, 2010 (8 a.m.–3 p.m. CST), Sheraton New Orleans Hotel, 500 Canal Street, New Orleans, LA 70130, 504–525–2500.

The discussions may address matters at issue in the following proceedings:

Docket No. EL09–40, Southwest Power Pool, Inc.
Docket No. ER06–451, Southwest Power Pool, Inc.
Docket No. ER08–923, Xcel Energy Services, Inc.
Docket No. ER08–1307, Southwest Power Pool, Inc.
Docket No. ER08–1308, Southwest Power Pool, Inc.
Docket No. ER08–1357, Southwest Power Pool, Inc.
Docket No. ER08–1358, Southwest Power Pool, Inc.
Docket No. ER08–1359, Southwest Power Pool, Inc.
Docket No. ER08–1419, Southwest Power Pool, Inc.
Docket No. ER09–35, Tallgrass Transmission LLC.
Docket No. ER09–36, Prairie Wind Transmission LLC.
Docket No. ER09–1397, Southwest Power Pool, Inc.