Docket No. ER09–262, *Southwest Power Pool, Inc.*

Docket No. ER09–336, *Southwest Power Pool, Inc.*

Docket No. ER09–342, *Southwest Power Pool, Inc.*

Docket No. ER09–443, *Southwest Power Pool, Inc.*

Docket No. ER09–659, *Southwest Power Pool, Inc.*

Docket No. ER09–748, *Southwest Power Pool, Inc.*

Docket No. ER09–883, *Southwest Power Pool, Inc.*

Docket No. ER09–1039, *Southwest Power Pool, Inc.*

Docket No. ER09–1042, *Southwest Power Pool, Inc.*

Docket No. ER09–1055, *Southwest Power Pool, Inc.*

Docket No. ER09–1056, *Southwest Power Pool, Inc.*

Docket No. ER09–1057, *Southwest Power Pool, Inc.*

Docket No. ER09–1068, *Southwest Power Pool, Inc.*

Docket No. ER09–1080, *Southwest Power Pool, Inc.*

Docket No. ER09–1130, *Southwest Power Pool, Inc.*

Docket No. ER09–1140, *Southwest Power Pool, Inc.*

Docket No. ER09–1152, *Southwest Power Pool, Inc.*

Docket No. ER09–1172, *Southwest Power Pool, Inc.*

Docket No. ER09–1174, *Southwest Power Pool, Inc.*

Docket No. ER09–1177, *Southwest Power Pool, Inc.*

Docket No. ER09–1192, *Southwest Power Pool, Inc.*

Docket No. OA08–5 and EL09–40, *Southwest Power Pool, Inc.*

Docket No. OA08–60, *Southwest Power Pool, Inc.*

Docket No. OA08–61, *Southwest Power Pool, Inc.*

Docket No. OA08–104, *Southwest Power Pool, Inc.*

These meetings are open to the public.

For more information, contact Patrick Clarey, Office of Energy Market Regulation, Federal Energy Regulatory Commission at (317) 249–5937 or *patrick.clarey@ferc.gov*.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12867 Filed 6–2–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division-Rate Order No. WAPA–144

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Transmission and Ancillary Services Rates.

SUMMARY: The Western Area Power Administration (Western) is proposing to update its rates for transmission and ancillary services for the Pick-Sloan Missouri Basin Program—Eastern Division (P-SMBP—ED). Current formula rates, under Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6 will expire on September 30, 2010. Western is also proposing to add a new rate schedule, Rate Schedule UGP–AS7, for Generator Imbalance Service. Western is proposing these rates to meet evolving and expanding transmission system and ancillary services requirements. Western will prepare a brochure that provides detailed information on the proposed rates to all interested parties. The proposed rates, under Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6, are scheduled to go into effect on January 1, 2010, and will remain in effect through December 31, 2014, or until superseded. The new rate schedule for Generator Imbalance Service, under Rate Schedule UGP–AS7, is scheduled to go into effect on the latter of January 1, 2010, or when Western's Open Access Transmission Tariff (OATT) is revised to provide for Generator Imbalance Service. If implemented, Rate Schedule UGP–AS7 will also remain in effect through December 31, 2014, or until superseded, to coincide with the other ancillary service rates in this rate order. Publication of this **Federal Register** notice begins the formal process for the proposed formula rates.

DATES: The consultation and comment period begins today and will end October 1, 2009. Western will present a detailed explanation of the proposed formula rates at a public information forum. The public information forum date is June 24, 2009, 9 a.m. to 12 p.m. CDT, Sioux Falls, South Dakota. Western will accept oral and written comments at a public comment forum. The public comment forum date is July 28, 2009, 9 a.m. to 12 p.m. CDT, Sioux Falls, South Dakota. Western will accept written comments any time during the consultation and comment period.

ADDRESSES: Written comments and/or requests to be informed of Federal Energy Regulatory Commission (FERC) actions concerning the rates submitted by Western to the FERC for approval should be sent to Robert J. Harris, Regional Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, e-mail *UGPISRate@wapa.gov.* Western will post information about the rate process on its Web site at *http://www.wapa.gov/ugp/rates/default.htm.* Western will post official comments received via letter and e-mail to its Web site after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure they are considered in Western's decision process. The public information forum location is the Holiday Inn, 100 West 8th Street, Sioux Falls, SD. The public comment forum location is the Holiday Inn, 100 West 8th Street, Sioux Falls, SD.

FOR FURTHER INFORMATION CONTACT: 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 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 transmission system, called the 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–FPT1, UGP–NFPT1, UGP–NT1, 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

[1] Western's OATT was most recently approved by FERC in Docket No. NJ07–2–000, 119 FERC 61,329 (2007) and the FERC's delegated 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.

annually. The proposed rates continue the formula-based approach and will be recalculated annually from financial and load information. Western intends for the proposed formula-based rates to go into effect January 1, 2010, and remain in effect through December 31, 2014. Annual recalculated rates are proposed go into effect on January 1, 2011, and annually on January 1 thereafter.

Proposed Change to Forward-Looking Formula Transmission Rates

Western proposes to change the implementation of the formula rates to recover transmission expenses and investments on a current (forward-looking), rather than a lagging basis. This will allow Western to more accurately match cost recovery with cost incurrence. Western will use projections to estimate transmission costs and load for the upcoming year in the annual recalculation of the Annual Transmission Revenue Requirement (ATRR). Western will ''true-up'' the cost estimates with Western's actual costs. This is a change in the manner in which the inputs for the revenue requirement are currently developed, rather than a change to the formula rate itself. Rates will continue to be recalculated every year. Revenue collected in excess of Western's actual net revenue requirement will be returned to customers through a credit against rates in a subsequent year. Actual revenues that are less than the net revenue requirement would likewise be recovered in a subsequent year. The true-up procedure would ensure that Western will recover no more and no less than the actual transmission costs for the year. For example, at the end of 2010, and as actual year-end financial data becomes available during 2011, the under or over collection of revenue during 2010 will be determined. When the rates are recalculated for implementation on January 1, 2012, the implemented rates will include an adjustment for revenue over or under collected in 2010.

Proposed Implementation of Transmission and Ancillary Services Rates on January 1

With the implementation of the applicable rates (resulting from this process) effective on January 1, 2010, Western proposes to change the date of the annual implementation of the recalculated rates for each applicable rate schedule to January 1, 2011, and January 1 of each year thereafter. In the past, annual implementation of the recalculation of the formula rates was effective annually on May 1. With the implementation date change from May 1 to January 1, the data used in the rate recalculation for the rates that will be effective on January 1will be made available for review and comment on or shortly after September 1 each year. Western proposes providing customers the opportunity to discuss and comment on the recalculated rates on or before October 31, 2010, and October 31 of subsequent years. This procedure will ensure that the data is available, interested parties are aware of the data used to calculate the rates, and will provide interested parties the opportunity to comment before the costs are collected through the formula rate.

Proposed Use of Revenue Requirement Calculation Templates

Western proposes to initiate the use of standard revenue requirement calculation templates for the annual rate recalculation to aid in the revenue requirement/rate recalculation and review processes. The revenue requirement templates will provide a standard format to gather and record required financial information from Western, Basin, Heartland, and Transmission Customers receiving facilities credits for facilities integrated with the IS. Entities submitting financial data may request the use of other or modified templates. However, once accepted, consistent use of the accepted template will be required for subsequent financial data submission for that entity. Western will review future requests to utilize other or modified templates for appropriateness and conduct a public process prior to granting approval for use.

Proposed Formula Rate for Network Transmission Service

The formula for calculating the Network Transmission Service rate is unchanged from Western's previously approved filing with the FERC. The change to a current year formula rate involves a change to the manner in which the inputs are developed rather than a change in the formula rate itself. The same ATRR is used for both network and point-to-point rates. The current methodology for determining the customers' charges 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 derived by annualizing the IS transmission investment and adding transmission-related annual costs, including operation, maintenance, interest, administrative and general costs, and depreciation. The annual costs are reduced by revenue credits for the Non-Firm Transmission Service. The load ratio share is based upon 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 point-to-point reservations. The Network Transmission Service rate includes costs for Scheduling, System Control, and Dispatch (SSCD) Service needed to provide transmission service. A revenue requirement template will be used to calculate the ATRR utilizing the costs estimates as data inputs.

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

Western proposes no change in the rate formula for Firm Point-to-Point IS Transmission Service other than utilizing transmission cost projections as data inputs in the determination of the annual revenue requirement as described above. The proposed Firm Point-to-Point IS Transmission Service rate remains the annual revenue requirement required for IS transmission service less the non-firm revenue credits all divided by annual average transmission system monthly peak load and then divided again by 12 months. The Firm Point-to-Point rate includes the cost for SSCD Service needed to provide transmission service.

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

Western proposes no change in the rate formula for Non-Firm Point-to-Point Transmission Service other than utilizing transmission 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 the monthly IS Firm Point-to-Point Transmission Service rate divided by 730 hours per month times 1000 mills per dollar.

Proposed Formula Rate for SSCD Service

Western proposes to continue the current formula-based rate methodology for SSCD Service, except that the formula will divide the annual revenue requirement for SSCD Service by the number of daily tags in the calculation year instead of dividing the annual revenue requirement by the number of daily schedules in the calculation year. This is a terminology change only. Schedules and tags have become synonymous in Western's Upper Great Plains Region, and therefore, calculating the SSCD Service rate with either as the denominator will result in the same rate. The change of terminology provides consistency among Western's regions in describing the formula for SSCD Service.

Proposed Formula Rate for Reactive Supply and Voltage Control 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's, Heartland's, and Missouri River Energy Services' annual costs for revenue requirements for RSVC Service are summed to get the total revenue requirement for this service. The RSVC rate is then derived by dividing the total annual revenue requirement by the load requiring reactive service. The annual cost is then divided by 12 months to obtain a monthly charge. 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 proposing a change to 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 proposing 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 also 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 rate formula will apply: Western's total P–SMBP–ED generation net plant multiplied by the generation fixed charge rate (in percent) provides Western's annual cost. That 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 is then summed with any revenue requirement or costs incurred from other non-Federal generators required by Western to operate outside the bandwidth to provide 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 annual cost is then divided by 12 months to obtain a monthly charge.

Proposed Formula Rate for Regulation and Frequency Response Service

Western proposes to 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 generation, both of which are United States Army Corps of Engineers (Corps) facilities. The Corps' generation fixed charge rate (in percent) is applied to Oahe and Fort Peck generation 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 to derive a dollar per kilowatt amount for Oahe's and Fort Peck's installed capacity (kWyear). This dollar per kilowatt amount is then applied to the capacity of Oahe and Fort Peck generation reserved for Regulation and Frequency Response Service 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 and adding cost associated with the purchase of power resources to provide Regulation and Frequency Response Service to support intermittent renewable resources as described below. The total Regulation and Frequency Response Service revenue requirement is determined by adding the Regulation and Frequency Response Revenue Requirement for Western, Basin, and Heartland. The Regulation and Frequency Response Service charge is then determined by dividing the total revenue requirement by the IS Network Load in the Control Area (kWyear). The annual cost 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

[3] Western has retained the term ''Control Area'' in this document maintaining consistency with usage of the term in the 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.

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 system demand or respond to transmission security constraints.

Proposed Rate for Energy Imbalance Service

Western proposes to revise its rate for Energy Imbalance Service to be consistent with rules promulgated by FERC to the extent consistent with Western's mission and 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 that charges be modified and based on deviation bands as follows:

(i) 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;

(ii) Deviations greater than +/−1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction(s) 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; and

(iii) 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 highest incremental cost that occurs that day for energy taken by the Transmission Customer in a scheduled hour that is greater than the energy scheduled, or 75 percent of the lowest incremental cost that occurs that day 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 Open Access Same-Time Information System (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.

Proposed Formula Rates for Operating Reserves Service—Spinning and Supplemental

Western proposes to 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 the Mid-Continent Area Power Pool 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 the operating reserve requirement of either 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.

Proposed Rate for Generator Imbalance Service

Western proposes to add a Generator Imbalance Service rate in a new rate schedule, 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 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. 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 schedules, is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Western proposes to base the rate on deviation bands as follows:

(i) 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;

(ii) 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; and

(iii) 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.

Notwithstanding the foregoing, 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.

Legal Authority

Western is proposing transmission and ancillary service rates for the P–SMBP—ED in accordance with section 302 of the Department of Energy (DOE) Organization Act (42 U.S.C. 7152). This section transferred to and vested in the Secretary of Energy the power marketing functions of the Secretary of the Department of 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)); and section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s); and other acts that specifically apply to the projects 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 FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985 (50 FR 37835).

After review of public comments, and possible amendments or adjustments, Western will recommend the Deputy Secretary of Energy approve the proposed rates on an interim basis.

Availability of Information

All brochures, studies, comments, letters, memorandums, or other documents that Western initiates or uses to develop the proposed rates are available for inspection and copying at the Upper Great Plains Regional Office, located at 2900 4th Avenue North, Billings, Montana. Many of these documents and supporting information are also available on its Web site under the ''2009 Transmission and Ancillary Services Rate Adjustment Process'' section located at *http://www.wapa.gov/ugp/rates/default.htm.*

Regulatory Procedure Requirements:

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969 (NEPA) (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 is in the process of determining whether an environmental assessment or an environmental impact statement should be prepared or if this action can be categorically excluded from those requirements.

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.

Dated: May 15, 2009.

Timothy J. Meeks,

Administrator.

[FR Doc. E9–12920 Filed 6–2–09; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–SFUND–2009–0078; FRL–8913–3]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; Brownfields Program—Revitalization Grantee Reporting (Renewal); EPA ICR No. 2104.03, OMB Control No. 2050–0192

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. The ICR, which is abstracted below, describes the nature of the information collection and its estimated burden and cost.