comment period. One of the earliest principles stated by Western in the initial MSTR development was to eliminate the pancaking of firm transmission rates. It was known that any elimination of pancaking of rates will result in a revenue loss to a single power system by virtue of the pancaked customer no longer having to pay two systems' rates for the same reservation. Western's customer choice model took this into account and chose a rate which would begin to eliminate pancaking while balancing the risk to the other power systems. Western projected additional other revenues would be realized in sufficient amounts to make up for any losses resulting from MSTR implementation.

Comment: A comment suggested Western re-open the public process to develop a customer choice model that would be supported by a majority of customers.

Response: Over a 2-year period, Western has explored numerous options for a multi-system transmission rate. Four options were customer choice models using various approaches. In all cases, for Western to be able to collect the full revenue requirement, some customers will incur increased costs as a result of a firm MSTR implementation. In other customer choice models explored by Western, varying levels of support were noted. However in no case did a majority of customers support the methodologies. Support was dependent upon the timing and the extent of potential cost increases.

Comment: A comment requested Western calculate the magnitude of rate decreases if revenue projections materialize without implementation of an MSTR.

Response: During the public process for the customer choice MSTR, Western presented a table showing some loss of firm revenues to the single system projects due to partial un-pancaking. Western projected mitigating this loss of revenues in order to provide for stable single system rates. Western's commitment to its customers is to keep rates as stable as possible for the foreseeable future. It is not appropriate to project a rate decrease given the many variables which may impact the rate calculation.

Comment: A comment suggested that if the MSTR is implemented, the return of funds to each single system should be based on the amount of transmission revenue lost due to MSTR implementation instead of based on the percentage share of total revenue requirement, as proposed by Western.

Response: The method the comment suggested is the methodology Western proposed in the initial MSTR presentation which would have had all customers converging to an MSTR in the fifth year.

This methodology resulted in a risk of increased costs to some customers. The comments received at that time correctly noted that any MSTR method that eliminates pancaking presents a risk of cost increases. However, MSTR could help mitigate this risk by freeing up additional capacity for sale.

Comment: Several comments suggested that Western abandon this proposal because the risks outweigh the benefits.

Response: After careful consideration of all comments, Western is withdrawing the proposal for a firm point-to-point MSTR rate at this time.

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 Desert Southwest Customer Service Regional Office, Western Area Power Administration, located at 615 South 43rd Avenue, Phoenix, Arizona. Many of these documents and supporting information are also available on Western's Web site at *http://www.wapa.gov/dsw/pwrmkt/MSTRP/MSTRP.htm.*

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. This action does not require a regulatory flexibility analysis since it is a rulemaking of particular applicability involving rates or services applicable to public property.

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321, *et seq.*); Council on Environmental Quality Regulations (40 CFR parts 1500–1508); and DOE NEPA Regulations (10 CFR part 1021), Western has determined 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.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

Dated: November 9, 2005.

Michael S. Hacskaylo,

Administrator.

[FR Doc. E5–6572 Filed 11–25–05; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division—Rate Order No. WAPA–126

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of order concerning power rates.

SUMMARY: The Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–126 and Rate Schedules P–SED–F8 and P–SED–FP8, placing firm power and firm peaking power rates from the Pick-Sloan Missouri Basin Program—Eastern Division (P–SMBP—ED) of the Western Area Power Administration (Western) into effect on an interim basis. The provisional rates will be in effect until the Federal Energy Regulatory Commission (Commission) confirms, approves, and places them into effect on a final basis or until they are replaced by other rates. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay power investment and irrigation aid, within the allowable periods.

DATES: Rate Schedules P–SED–F8 and P–SED–FP8 will be placed into effect on an interim basis on the first day of the first full billing period beginning on or after January 1, 2006, and will be in effect until the Commission confirms, approves, and places the rate schedules in effect on a final basis ending December 31, 2010, or until the rate schedules are superseded.

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, telephone (406) 247–7405, e-mail *rharris@wapa.gov*, or Mr. Jon R. Horst, Rates Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, telephone (406) 247–7444, e-mail *horst@wapa.gov*.

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy approved existing Rate Schedules P–SED–F7 and P–SED–FP7 for P–SMBP—ED firm power service and firm peaking power service on December 24, 2003 (Rate Order No. WAPA–110, 69 FR 649, January 6, 2004). The Commission confirmed and approved the rate schedules on December 23, 2004, in FERC Docket No. EF04–5031–000 (109 FERC 62,234). The existing rate schedules are effective from February 1, 2004, through December 31, 2008.

The P–SMBP—ED firm power and firm peaking power rates must be increased due to the economic impact of the drought, increased operation and maintenance and other annual expenses, increased investments, and increased interest expense associated with deficits. The studies have also been adjusted to account for calendar year implementation versus a fiscal year implementation.

The existing firm power Rate Schedule is being superseded by Rate Schedule P–SED–F8. Under Rate Schedule P–SED–F7, the energy charge is 9.62 mills per kilowatthour (mills/kWh), and the capacity charge is $3.72 per kilowattmonth (kWmonth). The composite rate is 16.51 mills/kWh. The provisional rates for P–SMBP—ED firm power are being implemented in two steps. The first step of the provisional firm power rates consists of an energy charge of 10.69 mills/kWh and a capacity charge of $4.20 per kWmonth. The first step of the provisional rates for P–SMBP—ED firm power in Rate Schedule P–SED–F8 will result in an overall composite rate of 18.47 mills/kWh on January 1, 2006, and will result in an increase of about 11.9 percent when compared with the existing P–SMBP—ED firm power rates under Rate Schedule P–SED–F7. The second step of the provisional firm power rates consists of an energy charge of 11.29 mills/kWh and a capacity charge of $4.45 per kWmonth. The second step of the provisional rates for P–SMBP—ED firm power in Rate Schedule P–SED–F8 will result in an overall composite rate of 19.54 mills/kWh on January 1, 2007, and will result in an increase of about 5.8 percent, with a total compounded increase after both steps of about 18.4 percent.

The existing firm peaking power Rate Schedule is being superseded by Rate Schedule P–SED–FP8. Under Rate Schedule P–SED–FP7, the firm peaking energy charge is 9.62 mills/kWh, and the firm peaking capacity charge is $3.72 per kWmonth. The first step of the provisional rates consists of an energy charge of 10.69 mills/kWh and a capacity charge of $4.20 per kWmonth on January 1, 2006. The second step of the provisional rates consists of an energy charge of 11.29 mills/kWh and a capacity charge of $4.45 per kWmonth on January 1, 2007.

The new rates will be higher than the existing rates, primarily due to increased purchased power and deferred annual expenses (deficits) associated with extended drought conditions. The proposed increase is more than 18 percent, which, combined with the recent rate increase in 2004, will result in a total increase in excess of 37 percent by 2007.

Incorporating these costs in the current Power Repayment Study confirms that existing rates do not provide enough revenue to repay irrigation assistance for Bureau of Reclamation Projects in future years. To meet Cost Recovery Criteria outlined in DOE Order RA 6120.2, a revised study and rate adjustment has been developed to demonstrate that sufficient revenues will be collected to meet future obligations.

The proposed rates will provide sufficient revenue to pay all annual costs, including interest expense, and meet required investment repayment within the allowable periods outlined in DOE Order RA 6120.2 and applicable legislation. Implementing the increase in two steps helps mitigate the financial impact of a single larger rate adjustment.

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 Commission. 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 00–001.00A, 10 CFR part 903, and 18 CFR part 300, I hereby confirm, approve, and place Rate Order No. WAPA–126, the proposed P–SMBP—ED firm power, and firm peaking power rates into effect on an interim basis. The new Rate Schedules P–SED–F8 and P–SED–FP8 will be promptly submitted to the Commission for confirmation and approval on a final basis.

Dated: November 9, 2005.

Clay Sell,

Deputy Secretary.

Department of Energy, Deputy Secretary

In the Matter of: Western Area Power Administration; Rate Adjustment; Pick-Sloan Missouri Basin Program—Eastern Division

Order Confirming, Approving, and Placing the Pick-Sloan Missouri Basin Program—Eastern Division Firm Power and Firm Peaking Power Service Rates Into Effect on an Interim Basis

These rates were 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)), 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 Commission. 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:

Administrator: The Administrator of the Western Area Power Administration.

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

Capacity Charge: The rate which sets forth the charges for capacity. It is expressed in $ per kWmonth.

Commission: Federal Energy Regulatory Commission.

Composite Rate: The rate for commercial firm power which is the total annual revenue requirement for capacity and energy divided by the total annual energy sales. It is expressed in mills/kWh and used for comparison purposes.

Corps: United States Army Corps of Engineers.

CROD: Contract rate of delivery. The maximum amount of capacity made available to a preference customer for a period specified under a contract.

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

Deficits: Deferred or unrecovered annual expenses.

DOE: United States Department of Energy.

DOE Order RA 6120.2: An order outlining with power marketing administration financial reporting and ratemaking procedures.

Energy: Measured in terms of the work it is capable of doing over a period of time. It is expressed in kilowatthours.

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

FERC: Federal Energy Regulatory Commission (to be used when referencing Commission Orders).

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

FRN: **Federal Register** notice.

Fry-Ark: Fryingpan-Arkansas Project.

FY: Fiscal year; October 1 to September 30.

Interior: United States Department of the Interior.

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.

LAP: Loveland Area Projects.

Load Factor: The ratio of average load in kW supplied during a designated period to the peak or maximum load in kW occurring in that period.

mills/kWh: Mills per kilowatthour—the unit of charge for energy (equal to one tenth of a cent or one thousandth of a dollar.)

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

NEPA: National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*).

O&M: Operation and Maintenance.

P–SMBP: The Pick-Sloan Missouri Basin Program

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

P–SMBP—WD: Pick-Sloan Missouri Basin Program—Western Division

Power: Capacity and energy.

Power Factor: The ratio of real to apparent power at any given point and time in an electrical circuit. Generally it is expressed as a percentage ratio.

Preference: The requirements of Reclamation Law which provide that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936 (Reclamation Project Act of 1939, section 9(c), 43 U.S.C. 485h(c)).

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

PRS: Power Repayment Study.

Rate Brochure: A document explaining the rationale and background for the rate proposal contained in this Rate Order dated June 2005.

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

Reclamation Law: A series of Federal laws. Viewed as a whole, these laws create the originating framework under which Western markets power.

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.

RMR: The Rocky Mountain Customer Service Region of Western.

UGPR: The Upper Great Plains Customer Service Region of Western.

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

Effective Date

The new provisional rates will take effect on the first day of the first full billing period beginning on or after January 1, 2006, and will remain in effect until December 31, 2010, pending approval by the Commission on a final basis.

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 proposed rate adjustment process began April 19, 2005, when Western mailed a notice announcing informal customer meetings to all P–SMBP—ED customers and interested parties. The meetings were held on May 10, 2005, in Denver, Colorado, and on May 11, 2005, in Sioux Falls, South Dakota. At these informal meetings, Western explained the rationale for the rate adjustment, presented rate designs and methodologies, and answered questions.

2. An FRN was published on June 16, 2005 (70 FR 35080) that announced the proposed rates for P–SMBP—ED, began a public consultation and comment period, and announced the public information and public comment forums.

3. On June 17, 2005, Western's UGPR mailed letters to all P–SMBP—ED preference customers and interested parties transmitting the FRN published on June 16, 2005.

4. On July 19, 2005, beginning at 10 a.m. (MDT), Western held a public information forum at the Radisson Stapleton Plaza in Denver, Colorado. On July 20, 2005, beginning at 8 a.m. (CDT), a second public information forum was held at Peru State College in Lincoln, Nebraska. On July 20, 2005, beginning at 2 p.m. (CDT), a third public information forum was held at the Sheraton Hotel and Convention Center in Sioux Falls, South Dakota. On July 21, 2005, beginning at 9 a.m. (CDT), a fourth public information forum was held at the Doublewood Inn in Fargo, North Dakota. Western provided detailed explanations of the proposed rates for P–SMBP—ED, and a list of issues that could change the proposed rates. Western also answered questions and gave notice that more information was available in the rate brochure.

5. On August 16, 2005, beginning at 9 a.m. (MDT), Western held a comment forum at the Radisson Stapleton Plaza in Denver, Colorado, to give the public an opportunity to comment for the record. No oral or written comments were received at this forum. On August 17, 2005, beginning at 9 a.m. (CDT), a second public comment forum was held at the Sheraton Hotel and Convention Center in Sioux Falls, South Dakota, to give the public an opportunity to comment for the record. Ten oral comments were received at this forum.

6. Western received 92 comment letters and 21 verbal comments from 94 entities during the consultation and comment period, which ended September 14, 2005. All formally submitted comments have been considered in preparing this Rate Order.

7. Western's UGPR provided a Web site with all of the letters, time frames, dates and locations of forums, documents discussed at the information meetings, FRNs, and all other information about this rate process for easy customer access. The Web site is located at *http://www.wapa.gov/ugp/rates/2006FirmRateAdj.*

Comments

Written comments were received from the following organizations:

Atlantic Municipal Utilities, Iowa
Basin Electric Power Cooperative, North Dakota
Breckenridge Public Utilities, Minnesota
Brown County Rural Electrical Association, Minnesota
Capital Electric Cooperative, Inc., North Dakota
Central Iowa Power Cooperative, Iowa
Central Power Electric Cooperative, Inc., North Dakota
City of Adrian, Minnesota
City of Akron, Iowa
City of Arlington, South Dakota
City of Auburn, Nebraska
City of Aurora, South Dakota
City of Benson, Minnesota
City of Big Stone City, South Dakota
City of Burke, South Dakota
City of Colman, South Dakota
City of Detroit Lakes, Minnesota
City of Estelline, South Dakota
City of Faith, South Dakota
City of Flandreau, South Dakota
City of Fort Pierre, South Dakota
City of Groton, South Dakota
City of Hawarden, Iowa
City of Howard, South Dakota
City of Jackson, Minnesota
City of Lakota, North Dakota
City of Luverne, Minnesota
City of Madison, South Dakota
City of McLaughlin, South Dakota
City of Melrose, Minnesota
City of Northwood, North Dakota
City of Orange City, Iowa
City of Parker, South Dakota
City of Paullina, Iowa
City of Pierre, South Dakota
City of Plankinton, South Dakota
City of Sioux Center, Iowa
City of Staples, Minnesota
City of Tyndall, South Dakota
City of Vermillion, South Dakota
City of Wadena, Minnesota
City of Watertown, South Dakota
City of Wessington Springs, South Dakota
City of White, South Dakota
City of Winner, South Dakota
Corn Belt Power Cooperative, Iowa
Dakota State University, South Dakota
Dawson Public Power District, Nebraska
East River Electric Power Cooperative, South Dakota
Federated Rural Electric, Minnesota
Hartley Municipal Utilities, Iowa
Heartland Consumers Power District, South Dakota
Lake Region Electric Cooperative, Minnesota
Lincoln Electric System, Nebraska
Manilla Municipal Utilities, Iowa
Marshall Municipal Utilities, Minnesota
McLeod Cooperative Power, Minnesota
Meeker Cooperative, Minnesota
Mid-West Electric Consumers Association, Colorado
Minnkota Power Cooperative, Inc., North Dakota
Missouri River Energy Services, South Dakota
Moorhead Public Service, Minnesota
Municipal Energy Agency of Nebraska, Nebraska
Nebraska Public Power District, Nebraska
Nobles Cooperative Electric, Minnesota
Northwest Iowa Power Cooperative, Iowa
Powder River Energy Corporation, Wyoming
Renville Sibley Cooperative Power Association, Minnesota
Rock Rapids Utilities, Iowa
Sanborn Municipal Light Plant, Iowa
Sauk Centre Public Utilities Commission, Minnesota
Sioux Valley Energy, South Dakota
Slope Electric Cooperative, Inc., North Dakota
South Dakota Municipal Electric Association, South Dakota
South Dakota Rural Electric Association
State of Montana-Department of Natural Resources and Conservation
State of South Dakota-Black Hills State University
State of South Dakota-Board of Regents
State of South Dakota-Bureau of Administration
State of South Dakota-Department of Corrections
State of South Dakota-Developmental Center/Redfield
State of South Dakota-Human Services Center
State of South Dakota-Mike Durfee State Prison
State of South Dakota-Northern State University
State of South Dakota-School of Mines and Technology
State of South Dakota-South Dakota State Penitentiary
State of South Dakota-South Dakota State University
Town of Pickstown, South Dakota
Town of Langford, South Dakota
Valley City Public Works, North Dakota
Valley Electric Cooperative, Montana
Woodbine Municipal Utilities, Iowa

Representatives of the following organizations made oral comments:

Basin Electric Power Cooperative, North Dakota
City of Barnesville, Minnesota.
City of Harlan, Iowa
City of Wadena, Minnesota
East River Electric Power Cooperative Inc., South Dakota
Federated Rural Electric, Minnesota
Lake Region Electric Cooperative, Minnesota
Lincoln Electric System, Nebraska
Mid-West Electric Consumers Association, Colorado
Minnkota Power Cooperative Inc., North Dakota
Missouri River Energy Services, South Dakota
Moorhead Public Service, Minnesota
Nebraska Public Power District, Nebraska
Valley City Public Works, North Dakota

Project Description

The P–SMBP was authorized by Congress in section 9 of the Flood Control Act of December 22, 1944, commonly referred to as the 1944 Flood Control Act. The multipurpose program provides flood control, irrigation, navigation, recreation, preservation and enhancement of fish and wildlife, and power generation. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota and Wyoming.

In addition to the multipurpose water projects authorized by section 9 of the Flood Control Act of 1944, certain other existing projects have been integrated with the P–SMBP for power marketing, operation and repayment purposes. The Colorado-Big Thompson, Kendrick and Shoshone Projects were combined with the P–SMBP in 1954, followed by the North Platte Project in 1959. These projects are referred to as the ''Integrated Projects'' of the P–SMBP.

The Flood Control Act of 1944 also authorized the inclusion of the Fort Peck Project with the P–SMBP for operation and repayment purposes. The Riverton Project was integrated with the P–SMBP in 1954, and in 1970 was reauthorized as a unit of P–SMBP.

The P–SMBP is administered by two regions. The UGPR with a regional office in Billings, Montana, markets power from the Eastern Division of P–SMBP, and the RMR with a regional office in Loveland, Colorado, markets the Western Division power of P–SMBP. The UGPR markets power in western Iowa, Minnesota, Montana east of the Continental Divide, North Dakota, South Dakota and the eastern two-thirds of Nebraska. The RMR markets P–SMBP power and Fry-Ark power, which in combination with P–SMBP—WD is known as LAP power, in northeastern Colorado, east of the Continental Divide

in Wyoming, west of the 101st meridian in Nebraska and northern Kansas. The P–SMBP power is marketed to approximately 300 firm power customers by the UGPR and approximately 40 firm power customers by the RMR.

Power Repayment Study—Firm Power Rate

Western prepares a PRS each FY to determine if revenues will be sufficient to repay, within the required time, all costs assigned to the P–SMBP revenues. Repayment criteria are based on law, policies including DOE Order RA 6120.2, and authorizing legislation. To meet Cost Recovery Criteria outlined in DOE Order RA 6120.2, a revised study and rate adjustment has been developed to demonstrate that sufficient revenues will be collected to meet future obligations.

Under this adjustment, payments toward irrigation assistance and capital debt are necessary before deficits are completely repaid. Traditionally, prepayment of irrigation assistance or capital is only done in the absence of deficits. However, if all revenue were applied toward deficits prior to making any payments for irrigation and other capital requirements, an extraordinarily large rate increase to meet single year repayment obligations would be required. Once these single year repayment obligations were satisfied, another rate adjustment would be necessary to decrease the rates. While repayment of capital debt and irrigation assistance prior to complete repayment of deficits is not typical, the approach approved within this Rate Order is well within the bounds of the discretion allowed under DOE Order RA 6120.2.

Under this adjustment, Western will repay all deficits and also make previously planned payments for irrigation assistance and other investments that are due in the years 2013 and 2014. Prepaying irrigation and capital investments has been part of the Pick-Sloan repayment plans and approved rate adjustments for the past 20 years. They are an integral part of the long-term plan for the project and have provided rate stability for consumers while meeting Federal repayment obligations. Modest irrigation and investment payments for a brief period of 2 to 3 years will reduce the single-year revenue requirement for irrigation assistance and hold increases to the ''lowest possible rates to consumers consistent with sound business principles,'' as outlined in section 5 of the Flood Control Act of 1944.

The provisional rates for P–SMBP—ED will be implemented in two steps. First step provisional rates are to become effective on an interim basis on the first day of the first full billing period beginning on or after January 1, 2006. Second step provisional rates are to become effective on the first day of the first full billing period beginning on or after January 1, 2007. Under Rate Schedule P–SED–F8, the first and second step provisional rates for P–SMBP—ED firm power will result in a total compounded composite rate increase of approximately 18.4 percent. The current composite rate under Rate Schedule P–SED–F7 is 16.51 mills/kWh. The provisional composite rate is 19.54 mills/kWh.

Existing and Provisional Rates

A comparison of the existing and provisional firm power and firm peaking power rates follow:

COMPARISON OF EXISTING AND PROVISIONAL RATES PICK-SLOAN MISSOURI BASIN PROGRAM—EASTERN DIVISION

Firm electric service	Existing rates	First step rates Jan. 1, 2006	Percent change	Second step rates Jan. 1, 2007	Percent change
P–SMBP—ED Revenue Requirement.	$160.1 million	$179.4 million	12.1	$189.9 million	5.9
P–SMBP—ED Composite Rate.	16.51 mills/kWh	18.47 mills/kWh	11.9	19.54 mills/kWh	5.8
Firm Capacity	$3.72/kWmonth	$4.20/kWmonth	12.9	$4.45/kWmonth	6.0
Firm Energy	9.62 mills/kWh	10.69 mills/kWh	11.1	11.29 mills/kWh	5.6
Tiered > 60 Percent Load Factor.	5.21 mills/kWh	5.21 mills/kWh	0.0	5.21 mills/kWh	0.0
Firm Peaking Capacity	$3.72/kWmonth	$4.20/kWmonth	12.9	$4.45/kWmonth	6.0
Firm Peaking Energy [1]	9.62 mills/kWh	10.69 mills/kWh	11.1	11.29 mills/kWh	5.6

[1] Firm Peaking Energy is normally returned. This rate will be assessed in the event Firm Peaking Energy is not returned.

Western Division

The LAP rate will be designed to cover the P–SMBP—WD revenue requirement for the P–SMBP and the revenue requirement for Fry-Ark. The adjustment to the LAP rate is a separate formal rate process which is documented in Rate Order No. WAPA–125. Rate Order No. WAPA–125 is also scheduled to go into effect on the first day of the first full billing period beginning on January 1, 2006.

Certification of Rates

Western's Administrator certified that the provisional rates for P–SMBP—ED firm power and firm peaking power rates are the lowest possible rates consistent with sound business principles. The provisional rates were developed following administrative policies and applicable laws.

P–SMBP—ED Firm Power Rate Discussion

According to Reclamation Law, Western must establish power rates sufficient to recover operation, maintenance, purchased power and interest expenses and repay power investment and irrigation aid.

The P–SMBP—ED firm power and firm peaking power rates must be increased due to the economic impact of the drought, increased O&M and other annual expenses, increased investments, and increased interest expense associated with deficits. The studies have also been adjusted to account for calendar year implementation versus a fiscal year implementation.

The existing rates for P–SMBP—ED firm power and firm peaking power under Rate Schedules P–SED–F7 and P–SED–FP7 expire December 31, 2008. Effective January 1, 2006, Rate Schedules P–SED–F7 and P–SED–FP7 will be superseded by the new rates in Rate Schedule P–SED–F8s and Rate Schedule P–SED–FP8. The provisional rates for P–SED–F8 firm power consist of a capacity charge and an energy charge. The provisional capacity charge is $4.45/kWmonth, and the provisional energy charge is 11.29 mills/kWh.

Statement of Revenue and Related Expenses

The following table provides a summary of projected revenue and expense data for the P–SMBP—ED firm power rate through the 5-year provisional rate approval period.

P–SMBP—ED Firm Power Comparison of 5-Year Rate Period (FY 2006–FY 2010) Total Revenues and Expenses

	Existing rate ($000)	Proposed rate ($000)	Difference ($000)
Total Revenues	$1,497,654	$1,694,242	$196,588
Revenue Distribution			
Expenses:			
O&M	762,873	832,279	69,406
Purchased Power and Wheeling	60,882	276,203	215,320
Integrated Projects Requirements	0	0	0
Interest	435,196	482,809	47,613
Transmission	67,063	70,537	3,474
Total Expenses	1,326,014	1,661,827	335,813
Principal Payments:			
Capitalized Expenses	169,152	30,764	(138,388)
Original Project and Additions [1]	1,128	1,128	0
Replacements [1]	1,360	523	(837)
Irrigation	0	0	0
Total Principal Payments	171,641	32,416	(139,225)
Total Revenue Distribution	1,497,654	1,694,242	196,588

[1] Due to the deficit or near-deficit conditions between 1999 and 2007, revenues generated in the cost evaluation period are applied toward repayment of deficits rather than repayment of project, additions and replacements. All deficits are projected to be repaid by 2017.

Basis for Rate Development

The existing rates for P–SMBP—ED firm power in Rate Schedule P–SED–F7 expire December 31, 2008. The existing rates no longer provide sufficient revenues to pay all annual costs, including interest expense, and repay investment and irrigation aid within the allowable period. The adjusted rates reflect increases due to the economic impact of the drought, increased O&M and other annual expenses, increased investments, and increased interest expense associated with deficits. The studies have also been adjusted to account for calendar year implementation versus fiscal year implementation. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay power investment and irrigation aid within the allowable periods. The provisional rates will take effect on January 1, 2006, to correspond with the start of the calendar year, and will remain in effect through December 31, 2010.

The P–SMBP—ED provisional firm power rate is designed to recover 50 percent of the revenue requirement from the capacity rate and 50 percent from the energy rate. The capacity rate of $4.45 per kWmonth is calculated by dividing 50 percent of the total annual revenue by the number of billing units (kWmonths) in a year. The energy rate of 11.29 mills/kWh is calculated by dividing 50 percent of the total annual revenue requirement by the annual energy sales. The capacity rate is applied to both firm power and firm peaking power. The energy rate is applied to firm energy and firm peaking energy that is not returned to Western.

The P–SMBP—ED firm peaking rate is equal to the capacity charge for the firm power rate. The firm peaking customer pays the capacity rate on their total firm peaking CROD each month rather than firm peaking delivered each month. Contract terms vary among firm peaking customers with respect to return of peaking energy. One firm peaking customer returns all peaking energy, while the other peaking customer may pay for 20 to 40 percent of the peaking energy they use and return the rest to Western. When a firm peaking customer keeps peaking energy the rate paid is the same as the firm energy rate.

Comments

The comments and responses regarding the firm power rate, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarification where necessary.

A. *Comment:* Western received numerous comments that strongly supported Western's original rate adjustment proposal which included a 2-step adjustment, calendar year implementation, no change to the tiered rate, and the proposed rates.

Response: Western appreciates the support it has received from the public for the original rate adjustment proposal.

B. *Comment:* One customer commented that Western should spread this rate increase into future years to help lessen the impact to its customers. Western received one comment preferring equal increases in each of the 2 years rather than the proposed approximate two-thirds and one-third plan.

Response: In accordance with DOE Order RA 6120.2, Western set the rate such that it is the lowest possible consistent with sound business principles. By adopting the 2-step rate adjustment, Western has spread the impact of the rate increase on the customers over a longer time. Spreading the rate increase over additional years or equal rate increases would cause the cumulative deficit to increase substantially and would not be consistent with sound business principles.

C. *Comment:* During the comment period, Western received 90 written comments and 21 verbal comments concerning the proposed Peaking Power Capacity Alternative. By far, most commenters indicated that Western should not accept the Peaking Power

Capacity Alternative because implementing a change in rate methodology would require a new rate design. Commenters also stated that shifting costs from firm peaking capacity customers to firm power customers is inappropriate, inequitable, and unjustified. Commenters suggested that peaking customers are getting a superior product, particularly in the summer season, to what other firm power customers are getting because they do not take as much off-peak energy, are not subject to load following scheduling limitations, and have very generous energy payback provisions or can buy high-value energy at the firm power rate. One peaking supporter commented that Western is obligated to act in the best interest of the entire customer base.

Several comments stated that Western should accept the Peaking Power Capacity Alternative based on it being more equitable in distributing the costs driving the rate increase. It was stated that due to the drought Western has purchased power, both on and off peak, in every month and given the terms of the peaking contracts, it is not equitable to include all these costs in the peaking customers' rates because they do not receive energy in every month. These commenters suggested that requiring peaking customers to pay a demand charge in months of no usage penalizes these customers and significantly increases the cost of power purchased under the peaking contract. Additionally, comments state that the peaking contract load factor has decreased since the inception of the contract and is significantly lower than the firm contract load factor. One firm peaking power customer stated that the effective cost of peaking power in 2004, after return of energy to Western, was $304/MWh in the summer and $2,914/MWh in the winter season. Another firm peaking power customer stated that its average per unit cost of firm power was $17.57/MWh and the cost for peaking power was $3,750/MWh. That customer also commented it participates in the energy markets on a daily basis and understands the value of the peaking contract. It stated this cost comparison is not used to prove that firm peaking is overpriced; instead it demonstrates that the products are different. Lastly, several comments suggest that operating applications under the contract are too restrictive.

Response: Because several customers indicated there was rate inequity between the firm peaking power product and the firm power product, Western included the Peaking Power Capacity Alternative in the Notice of Proposed Power Rates. Outlining the concerns of the peaking customers gives the public an opportunity to provide reasonable and logical documentation indicating that there is an inequity in rates charged for the firm peaking power product and the firm power product through the public process. While firm peaking power customers do receive several benefits from the firm peaking power product beyond those available to firm power product customers, Western does not recognize the firm peaking power product to be superior to the firm power product. Western does not find that comments supporting the Peaking Power Capacity Alternative provide an in-depth evaluation with supporting data to demonstrate inequities in charges between the products. To support the rate inequity between the firm power product and the peaking power product, a few comments used an energy cost analysis. In determining the true value of the firm peaking power product, Western believes it is unreasonable to focus solely on the energy component while ignoring the benefits of the capacity portion of the product. Comments supporting the Peaking Power Capacity Alternative also point to energy purchases as the majority of costs requiring the rate adjustment. They make the argument that energy purchase costs due to drought conditions are primarily associated with the firm power product and, therefore, a larger portion of the rate adjustment should be attributed to the firm power product. A thorough analysis of inequities between the firm peaking power product and the firm power product must look at the effect of energy sales as well as energy purchases. While it is true that energy purchases during a drought apply upward pressure on Western's rates, it is also true that surplus sales apply downward pressure during high water years. The comments fail to recognize that non-firm energy sales are the primary reason that both the firm peaking power product and the firm power product both enjoyed flat rates for the 10 years preceding the current drought period.

Western has determined that the rate increase should be spread among both firm power and firm peaking power customers following the practice historically used. Those comments received regarding the restrictions to the operational application of the firm peaking power product are outside the scope of this rate adjustment process. However, Western is willing to look at the operational applications and review possible restrictions to ensure equity in the firm peaking power product for all firm peaking power customers through Western's normal contract administration procedures. After considering the comments, Western has determined at this time it cannot justify moving to the Firm Peaking Capacity Alternative.

D. *Comment:* Western received one comment of concern that adequate long-term purchased power arrangements have not been pursued by the UGPR.

Response: Western continues to look into long-term purchased power arrangements on a seasonal basis. However, at this time long-term purchases that are available are not the most cost beneficial method of meeting Western purchase power requirements.

E. *Comment:* Western received one comment that encouraged Western to investigate ways to maximize the value of its assets, including transmission rights across neighboring systems and high-value transmission rights across constrained paths.

Response: Western continually looks for ways to increase revenues and decrease costs, including maximizing the use of the transmission system. However, Western has determined that this particular comment is not directly related to the proposed action and is outside the scope of this rate process.

Availability of Information

Information about this rate adjustment, including PRSs, 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 Plains Regional Office, Western Area Power Administration, 2900 4th Avenue North, Billings, Montana.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. Western has determined that this action does not require a regulatory flexibility analysis since it is a rulemaking of particular applicability involving rates or services applicable to public property.

Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321, *et seq.*); 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.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

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 the Commission 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, 2006, Rate Schedules P–SED–F8 and P–SED–FP8 for the Pick-Sloan Missouri Basin Program—Eastern Division of the Western Area Power Administration. The rate schedules shall remain in effect on an interim basis, pending the Commission's confirmation and approval of them or substitute rates on a final basis through December 31, 2010.

Dated: November 9, 2005.

Clay Sell,

Deputy Secretary.

Rate Schedule P–SED–F8; (Supersedes Schedule P–SED–F7)

Department of Energy, Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division Montana, North Dakota, South Dakota, Minnesota, Iowa, Nebraska

Schedule of Rates for Firm Power Service

Effective

First Step

The first day of the first full billing period beginning on or after January 1, 2006, through December 31, 2006.

Second Step

Beginning on the first day of the first full billing period beginning on or after January 1, 2007, through December 31, 2010.

Available

Within the marketing area served by the Eastern Division of the Pick-Sloan Missouri Basin Program.

Applicable

To the power and energy delivered to customers as firm power service.

Character and Conditions of Service

Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract.

Monthly Rate

First Step

Demand Charge: $4.20 for each kilowatt per month (kWmonth) of billing demand.

Energy Charge: 10.69 mills for each kilowatthour (kWh) for all energy delivered as firm power service. An additional charge of 5.21 mills/kWh, for a total of 15.90 mills/kWh, will be assessed for all energy delivered as firm power service that is in excess of a 60-percent monthly load factor and within the delivery obligations under the provisions of the power sales contract.

Billing Demand

The billing demand will be as defined by the power sales contract.

Second Step

Demand Charge: $4.45 for each kWmonth of billing demand.

Energy Charge: 11.29 mills for each kWh for all energy delivered as firm power service. An additional charge of 5.21 mills/kWh for a total of 16.50 mills/kWh will be assessed for all energy delivered as firm power service that is in excess of a 60 percent monthly load factor and within the delivery obligations under the provisions of the power sales contracts.

Billing Demand

The billing demand will be as defined by the power sales contract.

Adjustment for Character and Conditions of Service

Customers who receive deliveries at transmission voltage may in some instances be eligible to receive a 5 percent discount on capacity and energy charges when facilities are provided by the customer that result in a sufficient savings to Western to justify the discount. The determination of eligibility for receipt of the voltage discount shall be exclusively vested in Western.

Adjustment for Billing of Unauthorized Overruns

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at 10 times the above rate.

Adjustment for Power Factor

None. The customer will be required to maintain a power factor at the point of delivery between 95 percent lagging and 95 percent leading.

Schedule of Rates for Firm Peaking Power Service

Effective

First Step

The first day of the first full billing period beginning on or after January 1, 2006, through December 31, 2006.

Second Step

Beginning on the first day of the first full billing period beginning on or after January 1, 2007, through December 31, 2010.

Available

Within the marketing area served by the Eastern Division of the Pick-Sloan Missouri Basin Program, to our customers with generating resources enabling them to use firm peaking power service.

Applicable

To the power sold to customers as firm peaking power service.

Character and Conditions of Service

Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract.

Monthly Rate

First Step

Demand Charge: $4.20 for each kilowatt per month (kWmonth) of the effective contract rate of delivery for peaking power or the maximum amount scheduled, whichever is greater.

Energy Charge: 10.69 mills for each kilowatthour (kWh) for all energy scheduled for delivery without return.

Billing Demand

The billing demand will be the greater of:

1. The highest 30 minute integrated demand measured during the month up to, but not in excess of, the delivery obligation under the power sales contract, or

2. The contract rate of delivery.

Second Step

Demand Charge: $4.45 for each kWmonth of the effective contract rate of delivery for peaking power or the maximum amount scheduled, whichever is greater.

Energy Charge: 11.29 mills for each kWh for all energy scheduled for delivery without return.

Billing Demand

The billing demand will be the greater of:

1. The highest 30 minute integrated demand measured during the month up to, but not in excess of, the delivery obligation under the power sales contract, or

2. The Contract Rate of Delivery.

Adjustment for Billing for Unauthorized Overruns

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual obligation for peaking capacity and/or energy, such overrun shall be billed at 10 times the above rate.

[FR Doc. E5–6576 Filed 11–25–05; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[OPP–2005–0087; FRL–8003–1]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; Foreign Purchaser Acknowledgment Statement of Unregistered Pesticides, EPA ICR Number 0161.10, OMB Control Number 2070–0027

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces the submission of an Information Collection Request (ICR) to the Office of Management and Budget (OMB) for review and approval and provides an additional public review and comment opportunity. This is a request to renew an existing approved collection that is scheduled to expire on January 31, 2006. Under OMB regulations, the Agency may continue to conduct or sponsor the collection of information while this submission is pending at OMB. The ICR describes the nature of the information collection and its estimated burden and cost.

DATES: Additional comments may be submitted on or before December 28, 2005.

ADDRESSES: Submit your comments, referencing docket ID number OPP–2005–0087, to (1) EPA online using EDOCKET (our preferred method), by e-mail to *http://www.epa.gov/edocket*, or by mail to: EPA Docket Center, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460, and (2) OMB at: Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Nathanael R. Martin, Field and External Affairs Division, Office of Pesticide Programs, 7506C, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: 703–305–6475; fax number: 703–305–5884; e-mail address: *martin.nathanael@epa.gov.*

SUPPLEMENTARY INFORMATION: EPA has submitted the following ICR to OMB for review and approval according to the procedures prescribed in 5 CFR 1320.12. On April 20, 2005, (70 FR 20540), EPA sought comments on this ICR pursuant to 5 CFR 1320.8(d). EPA received one comment which is addressed in the supporting statement.

EPA has established a public docket for this ICR under Docket ID No. OPP–2005–0087, which is available for viewing online at *http://www.epa.gov/edocket*, or in person at the Public Information and Records Integrity Branch, Office of Pesticide Programs Docket, Rm. 119, Crystal Mall #2, 1801 S. Bell St., Arlington, VA. This docket facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The docket telephone number is (703) 305–5805. Use EDOCKET to submit or view public comments, access the index listing of the contents of the public docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the docket ID number identified above.

Any comments related to this ICR should be submitted to EPA and OMB within 30 days of this notice. EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing in EDOCKET as EPA receives them and without change, unless the comment contains copyrighted material, CBI, or other information whose public disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EDOCKET. The entire printed comment, including the copyrighted material, will be available in the public docket. Although identified as an item in the official docket, information claimed as CBI, or whose disclosure is otherwise restricted by statute, is not included in the official public docket, and will not be available for public viewing in EDOCKET. For further information about the electronic docket go to *www.epa.gov/edocket.*

Title: Foreign Purchaser Acknowledgment Statement of Unregistered Pesticides.

ICR Numbers: EPA ICR Number 0161.10, OMB Control Number 2070–0027.

Abstract: This information collection program is designed to enable EPA to provide notice to foreign purchasers of unregistered pesticides exported from the United States that the pesticide product cannot be sold in the United States. Section 17(a)(2) of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) requires an exporter of any pesticide not registered under FIFRA section 3 or sold under FIFRA section 6(a)(1) to obtain a signed statement from the foreign purchaser acknowledging that the purchaser is aware that the pesticide is not registered for use in, and cannot be sold in, the United States. A copy of this statement must be transmitted to an appropriate official of the government in the importing country. The purpose of the purchaser acknowledgment statement requirement is to notify the government of the importing country that a pesticide judged hazardous to human health or the environment, or for which no such hazard assessment has been made, will be imported into that country. This information is submitted in the form of annual or per-shipment statements to