through which 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 enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), were transferred to and vested in the Secretary of Energy (Secretary).

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to the Administrator of the Western Area Power Administration (Western), (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary, 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). This extension of rate methodology is issued pursuant to the Delegation Order and the Department of Energy (DOE) rate extension procedures at 10 CFR part 903.

Background

In the order issued March 10, 1998, in Docket No. EF98–5041–000, at 82 FERC ¶ 62,164, FERC confirmed, approved, and placed in effect on a final basis Rate Order No. WAPA–75, the Parker-Davis rate methodology for firm power service and firm and nonfirm point-to-point transmission service. The rate methodology set forth in Rate Order No. WAPA–75 was approved for the period beginning November 1, 1997, and ending September 30, 2002. On September 30, 2002, the Parker-Davis rate methodology for firm power service and firm and nonfirm point-to-point transmission service will expire. This makes it necessary to extend the existing Parker-Davis rate methodology pursuant to 10 CFR part 903. With this approval, Rate Order No. WAPA–75 will be extended under Rate Order No. WAPA–98.

Discussion

Western proposes to extend the existing Parker-Davis rate methodology used each Fiscal Year (FY) to calculate the firm power service rates for capacity and energy (Rate Schedule PD–F6), the firm point-to-point transmission service rate (Rate Schedule PD–FT6), the firm point-to-point transmission service rate for delivery of Salt Lake City Area Integrated Projects Power (Rate Schedule PD–FCT6) and the nonfirm point-to-point transmission service rate (Rate Schedule PD–NFT6). The existing Parker-Davis rate methodology provides for collecting annual revenues sufficient to recover annual expenses (including interest) and capital requirements, thus ensuring repayment of the project within the cost-recovery criteria set forth in DOE Order RA 6120.2. Under the existing Parker-Davis rate methodology, the revenue requirements for generation and transmission are determined annually based on FY projections in the cost apportionment study. The cost apportionment study allocates all Parker-Davis expenses and other revenues between generation and transmission. The revenue requirement for generation determines the amount of funds to collect through firm power service rates for capacity and energy. Similarly, the revenue requirement for transmission determines the amount of funds to collect through firm point-to-point transmission service.

During this extension period of the existing Parker-Davis rate methodology, Western will initiate a rate adjustment process in accordance with procedures for public participation in power and transmission rate adjustments in 10 CFR part 903. Western anticipates this rate adjustment process to begin when audited financial data for FY 2001 and FY 2002 becomes available. In the meantime, Western will continue to conduct informal customer meetings to ensure involvement of interested parties in the rate process.

In accordance with 10 CFR 903.23(a)(2), Western did not have a consultation and comment period and did not hold public information and comment forums. The notice of proposed extension of the Parker-Davis rate methodology for firm power service and firm and nonfirm point-to-point transmission service was published in the **Federal Register** (67 FR 34702) on May 15, 2002.

Order

In view of the foregoing, I hereby extend for a period effective October 1, 2002, and ending September 30, 2004, the existing Parker-Davis rate methodology for determining the firm power service rate and the firm and nonfirm point-to-point transmission service rates.

Dated: September 13, 2002.

Spencer Abraham,

Secretary.

[FR Doc. 02–24425 Filed 9–25–02; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Salt Lake City Area Integrated Projects and Colorado River Storage Project—Rate Order No. WAPA–99

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Rate Order.

SUMMARY: The Secretary of the Department of Energy (DOE) confirmed and approved Rate Order No. WAPA–99 and Rate Schedule SLIP–F7, placing firm power rates from the Salt Lake City Area Integrated Projects (SLCA/IP) of the Western Area Power Administration (Western) into effect on an interim basis. The Secretary also confirmed Rate Schedules SP–PTP6, SP–NW2, SP–NFT5, SP–SD2, SP–RS2, SP–EI2, SP–FR2, and SP–SSR2, placing firm and non-firm transmission rates and ancillary services rates on the Colorado River Storage Project (CRSP) transmission system into effect 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 replaced by other rates. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, repayment of investment, and irrigation aid within the allowable periods.

DATES: Rate Schedules SLIP–F7, SP–PTP6, SP–NW2, SP–NFT5, SP–SD2, SP–RS2, SP–EI2, SP–FR2, and SP–SSR2 will be placed into effect on an interim basis on the first day of the first full billing period beginning on October 1, 2002, and will be in effect until FERC confirms, approves, and places the rate schedules in effect on a final basis through September 30, 2007, or until the rate schedules are superseded.

FOR FURTHER INFORMATION CONTACT: Mr. Bradley S. Warren, CRSP Manager, CRSP Management Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, (801) 524–6372, or Ms. Carol Loftin, Rates Manager, CRSP Management Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, (801) 524–6380, or e-mail *loftinc@wapa.gov.*

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy approved the existing Rate Schedule SLIP–F6 for SLCA/IP firm power, Rate Schedules SP–PTP5, SP–NW1, and SP–NFT4 for firm and non-firm transmission, and Rate Schedules SP–SD1, SP–RS1, SP–EI1, SP–FR1, and SP–SSR1 for ancillary services on March 23, 1998 (Rate Order No. WAPA–78, April 6, 1998), and FERC confirmed and approved the rate schedules on July 17, 1998, in FERC Docket No. EF98–5171–000. The existing rate schedules became effective April 1, 1998, through March 30, 2003.

The existing firm power Rate Schedule is being superseded by Rate Schedule SLIP–F7. Under Rate Schedule SLIP–F6, the energy rate is 8.10 mills per kilowatthour (mills/kWh), and the capacity rate is $3.44 per kilowattmonth (kWmonth). The composite rate is 17.57 mills/kWh. The provisional firm power rate consists of an energy charge of 9.5 mills/kWh and a capacity charge of $4.04 per kWmonth. The provisional rates for SLCA/IP firm power in Rate Schedule SLIP–F7 will result in an overall composite rate of 20.72 mills/kWh on October 1, 2002, and will result in an increase of about 18 percent when compared with the existing SLCA/IP firm power rates under Rate Schedule SLIP–F6.

Rate Schedules SP–PTP6, SP–NW2, and SP–NFT5 supersede Rate Schedules SP–PTP5, SP–NW1, and SP–NFT4, respectively. Provisional formula rates developed for CRSP transmission services are consistent with FERC Order No. 888. Under Rate Schedules SP–PTP5 and SP–NFT4, the CRSP transmission rates are $1.78/kWmonth for firm service and a maximum of 2.43 mills/kWh for non-firm service. On October 1, 2002, the provisional formula rate in Rate Schedule SP–PTP6 results in a rate of $2.06/kWmonth for firm CRSP transmission service, a 16-percent increase when compared with the existing rate. The provisional formula rate in Rate Schedule SP–NFT5 results in a maximum rate of 2.82 mills/kWh for non-firm service, a 16-percent increase when compared with the existing rate.

The provisional formula for network integration transmission service in Rate Schedule SP–NW2 will be the same as the existing formula rate for network integration transmission service under Rate Schedule SP–NW1.

The existing transmission rates include costs for scheduling, system control, and dispatch services. The transmission provisional formula rates include the costs of this service.

Rate Schedules SP–SD2, SP–RS2, SP–EI2, SP–FR2, and SP–SSR2 supersede Rate Schedules SP–SD1, SP–RS1, SP–EI1, SP–FR1, and SP–SSR1, respectively. Ancillary services are being updated slightly to reflect minor changes.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of DOE delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to Western's Administrator, (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary, 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) became effective on September 18, 1985.

Pursuant to Delegation Order No. 00–037.00 and existing Department of Energy procedures for public participation in power rate adjustments at 10 CFR part 903 and 18 CFR part 300, procedures for approving Power Marketing Administration rates by FERC, Rate Order No. WAPA–99, confirming, approving, and placing the proposed SLCA/IP firm power rate, CRSP firm and non-firm transmission rates, and ancillary services rates into effect on an interim basis, is issued, and the new Rate Schedules SLIP–F7, SP–PTP6, SP–NW2, SP–NFT5, SP–SD2, SP–RS2, SP–EI2, SP–FR2, and SP–SSR2 will be promptly submitted to FERC for confirmation and approval on a final basis.

Dated: September 10, 2002.

Spencer Abraham,

Secretary.

Western Area Power Administration Rate Adjustment for the Salt Lake City Area Integrated Projects and Colorado River Storage Project; Order Confirming, Approving, and Placing the Salt Lake City Area Integrated Projects Firm Power, Colorado River Storage Project Transmission, and Ancillary Services Rates into Effect on an Interim Basis

The Western Area Power Administration (Western) developed these rates pursuant to the Department of Energy Organization Act (42 U.S.C. 7101–7352). The Department of Energy Organization Act transferred the power marketing functions of the Secretary 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 enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts specifically applicable to the projects involved, to the Secretary of Energy (Secretary).

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of DOE delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to Western's Administrator, (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary, 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) became effective on September 18, 1985.

Acronyms and Definitions

As used in this rate order, the following acronyms and definitions apply:

1–CP: 1-month coincident peak for year.
12–CP: 12-month coincident peak average.
A–LP: Animas-LaPlata Project.
Administrator: Western's Administrator.
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.
AHP: Available Hydropower.
Basin Fund: Upper Colorado River Basin Fund.
Capacity: The electric capability of a generator, transformer, transmission circuit, or other equipment. It is expressed in kW.
Capacity Rate: The rate which sets forth the charges for capacity. It is expressed in $ per kWmonth.
CDP: Customer Displacement Power.
Collbran: Collbran Project.
Composite Rate: The rate for commercial firm power and 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.
Contractor: An entity which has a contract with Western for SLCA/IP Firm Electric Service. (*See also* Customer)
CME: Capitalized Movable Equipment.
CROD: Contract rate of delivery. The maximum amount of capacity made available to a preference customer for a period specified under a contract.
CRSP: Colorado River Storage Project.
CRSP Act: Act of April 11, 1956, ch. 203, 70 Stat. 105, as amended, 43 U.S.C. 620–620o.
CRSP MC: The CRSP Management Center of Western.
CUP: Central Utah Project.
Customer: An entity with a contract which is receiving service from Western's CRSP MC.
DOE: United States Department of Energy.

DOE Order RA 6120.2: An order dealing with power marketing administration financial reporting and rate-making procedures.
DPR: Definite Plan Report of the CUP.
DSWR: The Desert Southwest Region of Western.
Energy: Measured in terms of the work it is capable of doing over a period of time. It is expressed in kWh.
Energy Rate: The rate which sets forth the charges for energy. It is expressed in mills/kWh and applied to each kWh delivered to each customer.
FERC: Federal Energy Regulatory Commission.
Firm: A type of product and/or service available at the time requested by the customer.
FRN: **Federal Register** notice.
FTE: Full-time equivalent. Represents one full-time employee.
FY: Fiscal year; October 1 to September 30.
GCPA: Grand Canyon Protection Act of 1992.
GWh: Gigawatthour—the electrical unit of energy that equals 1 billion watthours or 1,000,000 kWh.
Integrated Projects: The resources and revenue requirements of the Collbran, Dolores, Rio Grande, and Seedskadee projects blended together with the CRSP to create the SLCA/IP resources and rate.
kW: Kilowatt—the electrical unit of capacity that equals 1,000 watts.
kWmonth: Kilowattmonth—the electrical unit of the monthly amount of capacity.
kWh: Kilowatthour—the electrical unit of energy that equals 1,000 watts in 1 hour.
Load: The amount of electric power or energy delivered or required at any specified point(s) on a system.
Merchant Function: A Power Marketing function within the CRSP MC that balances loads and resources for the CRSP MC, other regions within Western, and customers and purchases and sells energy on the open market.
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.
NEPA: National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*).
Net Revenue: Revenue remaining after paying all annual expenses.
Non-firm: A type of product and/or service not always available at the time requested by the customer.
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.
OM&R: Operation, Maintenance & Replacement.
PAR: Purchase Adder Rate.
Participating Projects: The Dolores and Seedskadee projects participating with CRSP according to the CRSP Act of 1956.
Power: Capacity and energy.
Project Use: Power used to operate SLCA/IP and CRSP facilities pursuant to Reclamation Law.
Provisional Rate: A rate which has been confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary of DOE.
PRS: Power repayment study.
Rate Brochure: A document explaining the rationale and background of the rate proposal contained in this Rate Order dated February 2002.
Rate-Setting PRS: The PRS used for the rate adjustment proposal.
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, deferred expenses, and repayment of Federal investments, and other assigned costs.
RIP: Recovery Implementation Program.
RMR: The Rocky Mountain Region of Western.
Secretary: Secretary of Energy.
SCADA: Supervisory Control and Data Acquisition.
SHP: Sustainable Hydro Power.
SLCA/IP: Salt Lake City Area Integrated Projects—The resources and revenue requirements of the Collbran, Dolores, Rio Grande, and Seedskadee projects blended together with the CRSP to create the SLCA/IP resources and rate.
Supporting Documentation: A compilation of data and documents that support the Rate Brochure and the rate proposal.
WACM: Western Area Colorado Missouri control area, operated by RMR.
WALC: Western Area Lower Colorado control area, operated by DSWR.
Western: United States Department of Energy, Western Area Power Administration.
Western Regions: Customer service regions of Western Area Power Administration.
Western's Tariff: Western's Open Access Transmission Service Tariff.
Work Plan: A draft estimate of costs that are expected to become the Congressional Budget for Western and Reclamation.
WRP: Western Replacement Power.
WECC: Western Electricity Coordinating Council.
WSPP: Western Systems Power Pool.

Effective Date

The new interim rates will take effect on the first day of the first full billing period beginning on or after October 1, 2002, and will be in effect pending their approval by FERC or substitute final rates for 5 years ending September 30, 2007, or until superseded.

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 ensure involvement of interested parties in the rate process were:

1. The proposed rate adjustment process began September 18, 2001, when Western mailed a notice announcing informal customer meetings to all SLCA/IP customers and interested parties.

2. Western mailed a notice on October 3, 2001, announcing the change of dates and locations for informal customer meetings to one meeting. The meeting was held on October 18, 2001, in Salt Lake City, Utah. At this informal meeting, Western explained the rationale for the rate adjustment, presented rate designs and methodologies, and answered questions.

3. On March 4, 2002, Western's CRSP MC mailed letters to all SLCA/IP preference customers and interested parties transmitting the Brochure for Proposed Rates and the **Federal Register** notice due to be published on March 6, 2002.

4. A **Federal Register** notice published on March 6, 2002 (67 FR 10189), officially announced the proposed rates for SLCA/IP and CRSP, began a public consultation and comment period, and announced the public information and public comment forums.

5. On March 19, 2002, beginning at 10 a.m., Western held a public information forum at the Hilton Salt Lake City Center in Salt Lake City, Utah. Western provided detailed explanations of the proposed rates for SLCA/IP and CRSP, provided a list of issues that could change the proposed rates, answered questions, and gave notice that additional information would be provided at a second information forum

before the public comment forum. Rate Brochures, Supporting Documentation, and informational handouts were also provided.

6. On April 12, 2002, Western's CRSP MC mailed letters to all SLCA/IP preference customers and interested parties notifying them of the second public information forum and providing a table which illustrated the proposed changes to be discussed.

7. On April 23, 2002, beginning at 10 a.m., Western held a second public information forum at the Hilton Salt Lake City Center in Salt Lake City, Utah. Western provided updates to the proposed firm power rates, and answered questions.

8. On April 23, 2002, beginning at 11:15 a.m., Western held a comment forum to give the public an opportunity to comment for the record. Seven individuals commented at this forum.

9. Western received 21 comment letters during the consultation and comment period, which ended June 4, 2002. All formally submitted comments have been considered in preparing this Rate Order.

Comments

Written comments were received from the following organizations:

Bureau of Reclamation, Upper Colorado Region, Utah
Bountiful City Light and Power, Utah
Bridger Valley Electric Association, Wyoming
City of Farmington, New Mexico
Colorado River Energy Distributors Association, Arizona
Deseret Power Electric Cooperative, Utah
Dixie-Escalante Electric Cooperative, Utah
Fillmore City, Utah
Holden Town, Utah
Holy Cross Energy, Inc., Colorado
Irrigation & Electrical Districts Association of Arizona, Arizona
Kanosh Town, Utah
Kaysville City, Utah
Morgan City, Utah
Murray City Corporation, Utah
Platte River Power Authority, Colorado
Provo City Power, Utah
Salt River Project, Arizona
Strawberry Electric Service District, Utah
Tri-State Generation and Transmission Association, Inc., Colorado
Utah Associated Municipal Power Systems, Utah

Representatives of the following organizations made oral comments:

Colorado River Energy Distributors Association, Arizona
Deseret Power Electric Cooperative, Utah
Irrigation & Electrical District Association, Arizona
Manti City Power, Utah
Nephi City Power, Utah
Utah Municipal Power Association, Utah

Project Description

The SLCA/IP consists of the CRSP, Rio Grande, and Collbran projects. The CRSP described here includes two CRSP participating projects that have power facilities, the Dolores and Seedskadee projects. The Rio Grande and Collbran projects were integrated with CRSP for marketing and rate-making purposes on October 1, 1987. The goals of integration were to increase marketable resources and to simplify contract and rate development and project administration by creating one rate and assuring repayment of the Projects' costs. All Integrated Projects maintain their individual identities for financial accounting and repayment purposes, but their revenue requirements are integrated into one PRS for rate-making, known as the SLCA/IP.

Power Repayment Study—Firm Power Rate

Western prepares a PRS each FY to determine if revenues will be sufficient to repay, within the prescribed time periods, all costs assigned to the SLCA/IP revenues. Repayment criteria are based on law, policies including DOE Order RA 6120.2, and authorizing legislation.

The proposed rates for SLCA/IP firm power result in an overall composite rate increase of approximately 18 percent on October 1, 2002, when compared to the existing SLCA/IP firm power rates in Rate Schedule SLIP–F6. The composite rate under Rate Schedule SLIP–F6 is 17.57 mills/kWh, and the proposed composite rate is 20.72 mills/kWh. The following table compares the current and proposed firm power rates.

COMPARISON OF CURRENT AND PROPOSED FIRM POWER RATES

Rate schedule	Current rate SLIP–F6	Proposed rate SLIP–F7	Increase
Energy (mills/kWh)	8.1	9.5	1.4
Capacity ($/kWmonth)	3.44	4.04	.60
Composite Rate: (mills/kWh)	17.57	20.72	3.15

CRSP Transmission Rate Study

A transmission service rate study was prepared to ensure that transmission service rates are based on the cost of service of the CRSP transmission system. This study includes all transmission expenses and associated offsetting revenues. Transmission service rates are charged separately to entities receiving transmission-only services over the CRSP transmission system.

Western is proposing firm and non-firm transmission rate formulas to annually calculate rates applicable to all current and future CRSP transmission service. The current firm and non-firm CRSP transmission rate formulas became effective on April 1, 1998. The proposed transmission rate formulas are expected to be effective October 1, 2002, through September 30, 2007. These rate formulas include costs for scheduling, system control, and dispatch service. The cost of transmission service for Western's SLCA/IP long-term firm electric service will continue to be included in the SLCA/IP firm power rate. Transmission services are outlined in Western's Tariff.

A new rate methodology is being proposed that is more consistent with the methodology used at other Western regions and other utilities. The proposed methodology is an annual fixed charge formula that will be used to determine the revenue requirement to be recovered from firm and non-firm transmission service. The annual transmission revenue requirement includes O&M expenses, administrative and general expenses, interest expense, and depreciation expense. This methodology is updated annually using the most recent historical test year. This revenue requirement is offset by appropriate CRSP transmission system revenues.

The provisional rate for non-firm CRSP transmission service is based upon the current CRSP firm point-to-point transmission rate, and may be discounted. The provisional rate is expressed in mills/kWh and is a maximum of 2.82 mills/kWh for FY 2003.

The provisional rate for network integration transmission service is a formula calculation based on the annual transmission revenue requirement. There are no changes to the existing network integration transmission service formula under Rate Schedule SP–NW1.

Firm Point-to-Point

The CRSP MC is seeking approval of a rate formula for calculation of the firm point-to-point transmission rate, to be applied annually. The provisional rate for firm point-to-point CRSP transmission service is $2.06 per kWmonth for FY 2003, a 16-percent increase from the existing firm transmission rate of $1.78 per kWmonth, which became effective April 1, 2002.

The firm point-to-point transmission rate is based on a test year using an annual fixed charge methodology. This test year is the most recent historical data available. The annual transmission revenue requirement is reduced by revenue credits such as non-firm transmission, existing contracts at different rates, scheduling and dispatch services, and phase shifter revenues. The resultant net annual transmission revenue requirement is divided by the capacity reservation needed to meet firm power and transmission-only commitments in kW, including the total network integration loads at system peak, to derive a cost/kWyear. The formula is updated each year by applying the most current historical test year. If needed, a revised rate will become effective each October 1. The rate formula is proposed to be effective October 1, 2002, through September 30, 2007.

The cost/kWyear is calculated using the following formula:

1. $\text{ARR} - \text{TRC} = \text{NARR}$

2. $\dfrac{\text{NARR}}{\text{TSTL}}$

Where:

ARR = Annual Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expense, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system not related to the revenues from the sale of long-term firm transmission.

NARR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement minus Transmission Revenue Credits.

TSTL = CRSP Transmission System Total Load. The sum of the total CRSP transmission capacity under long-term reservation including the total network integration loads at system peak.

Non-Firm Point-to-Point

The proposed rate for non-firm point-to-point CRSP transmission service is a mills/kWh rate which is based upon the current firm point-to-point rate and may be discounted. This rate will remain in effect concurrently with the firm point-to-point rate and will also be reviewed annually. Transmission availability will be posted on Western's OASIS.

Network

The proposed rate for network transmission is a formula calculation based upon the annual revenue requirement then in effect, as determined by the annual fixed charge methodology. Western is not currently providing network transmission on its CRSP transmission system.

Ancillary Services

Six ancillary services will be offered by CRSP MC, two of which are required. These are (1) scheduling, system control, and dispatch service and (2) reactive supply and voltage control service. The remaining four ancillary services, (3) regulation and frequency response service, (4) energy imbalance service, (5) spinning reserve service, and (6) supplemental reserve service, will also be offered either from the control area or from the CRSP Merchant Function. Sales of regulation and frequency response, energy imbalance, spinning reserve, and supplemental reserve services from SLCA/IP power resources are limited since Western has allocated the SLCA/IP power resources to preference entities under long-term commitments. The availability and type of ancillary service will be determined based on excess resources available at the time the service is requested, except for the two ancillary services required to be provided in conjunction with the sale of CRSP transmission services.

Since the CRSP transmission system lies in two control areas operated by Western's RMR and DSWR, many of the ancillary services are offered through their respective control areas.

The provisional rates for ancillary services are designed to recover only the costs associated with providing the service(s). The costs for providing scheduling, system control, and dispatch service are included in the appropriate provisional transmission services rates. However, the charges for reactive supply and voltage control service will be in accordance with Western's DSWR and RMR applicable rate schedules.

Existing and Provisional Rates

A comparison of the existing and provisional firm power, transmission and ancillary services rates follows:

COMPARISON OF EXISTING AND PROVISIONAL SALT LAKE CITY AREA/INTEGRATED PROJECTS FIRM POWER, COLORADO RIVER STORAGE PROJECT TRANSMISSION AND ANCILLARY SERVICES

	Existing rates	Provisional rates (effective 10/1/02)	% Change
Firm Capacity Charge ($/kWmonth)	$3.44	$4.04	17
Firm Energy Charge (mills/kWh)	8.10	9.50	17
Composite Rate (mills/kWh)	17.57	20.72	18
Firm Transmission Rate ($/kWmonth)	1.78	2.06	16
Network Transmission (Net Annual Revenue Requirement)	54,968,215	65,279,468	19
Non-firm Transmission Rate	2.43 mills/kWh, may be discounted.	2.82 mills/kWh, may be discounted.	16

COMPARISON OF EXISTING AND PROVISIONAL SALT LAKE CITY AREA/INTEGRATED PROJECTS FIRM POWER, COLORADO RIVER STORAGE PROJECT TRANSMISSION AND ANCILLARY SERVICES—Continued

	Existing rates	Provisional rates (effective 10/1/02)	% Change
Ancillary Services [1]	N/A	N/A	N/A

[1] Since most of CRSP transmission facilities are located in two other Western control areas, many of these services are provided through these control areas.

Certification of Rates

Western's Administrator certified that the interim rates for SLCA/IP firm power, CRSP transmission, and ancillary services are the lowest possible rates consistent with sound business principles. The provisional rates were developed following administrative policies and applicable laws.

SLCA/IP Firm Power Rate Discussion

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

The SLCA/IP firm power rate needs to be increased due to recent higher-than-expected O&M and purchased power costs that have occurred since the existing rate was established. Future projections for O&M have also increased in the Rate-Setting PRS. It is also expected that near term hydrogeneration will be lower than normal in the next 2 years which will require greater than normal purchased power costs.

These higher-than-expected O&M and purchased power costs have created deficits or near-deficits within the CRSP PRS since 1999. These deficit or near-deficit conditions are expected to continue through 2004. The deficits are projected to be repaid by 2005.

The increased revenue requirements are partially offset by an increase in projections for offsetting revenues such as Merchant Function, non-firm transmission, and ancillary services revenues.

The existing rate for SLCA/IP firm power under Rate Schedule SLIP–F6 expires March 30, 2003. Effective October 1, 2002, Rate Schedule SLIP–F6 will be superseded by the new rates in Rate Schedule SLIP–F7. The provisional rates for SLCA/IP firm power consist of a capacity rate and an energy rate. The provisional capacity rate is $4.04/kWmonth, and the provisional energy rate is 9.5 mills/kWh.

Statement of Revenue and Related Expenses

The following table provides a summary of projected revenue and expense data for the SLCA/IP firm power rate through the 5-year provisional rate approval period.

SLCA/IP FIRM POWER COMPARISON OF 5-YEAR RATE PERIOD (FY 2003–FY 2007) TOTAL REVENUES AND EXPENSES

	Existing rate ($000)	Proposed rate ($000)	Difference ($000)
Total Revenues	$636,189	$772,317	$136,128
Revenue Distribution:			
Annual expenses			
O&M	176,600	286,644	110,044
Purchased Power and Wheeling	59,375	131,926	72,551
Integrated Projects Requirements	42,331	43,335	1,004
Interest	60,442	174,765	114,323
Other	9,428	31,323	21,895
Total annual expenses	348,176	667,993	319,817
Annual principal payments			
Capitalized Expenses	0	19,257	19,257
Original Project and Additions [1]	158,654	79,941	(78,713)
Replacements [1]	127,117	2,810	(124,307)
Irrigation	2,242	2,316	74
Total principal payments	288,013	104,324	(207,316)
Total Revenue Distribution	636,189	772,317	136,128

[1] Due to the deficit or near-deficit conditions between 1999 and 2004, revenues generated in the cost evaluation period are applied towards repayment of deficits rather than repayment of project, additions, and replacements. All deficits are projected to be repaid by 2005.

Basis for Rate Development

The existing rates for SLCA/IP firm power in Rate Schedule SLIP-F6 expire March 30, 2003. The existing rates no longer provides sufficient revenues to pay all annual costs, including interest expense, and repayment of investment and irrigation aid within the allowable period. The adjusted rates reflect increases primarily in O&M costs, purchase power costs, and interest expenses. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of investment and irrigation aid within the allowable periods. The provisional rates will take effect on October 1, 2002, to correspond with the start of the Federal fiscal year, and will remain in effect through September 30, 2007.

The provisions for transformer losses adjustment, power factor adjustment, Western Replacement Power adjustment, and Customer Displacement Power administrative charges adjustment are part of the provisional rates for SLCA/IP firm power. The provisions and methodologies for these adjustments are not being modified and will remain as specified in SLIP–F6.

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.

The issues discussed are (1) Purchase Adder Rate (PAR), (2) Purchase Power, (3) O&M, (4) Central Utah Project (CUP), (5) status of issues which were identified as outstanding in the Rate Brochure, (6) Merchant Function Revenues, (7) Basin Fund, and (8) miscellaneous comments.

1. PAR

Comment: Because of the potential volatility and magnitude of the PAR, a majority of the comment letters received by the CRSP MC suggested that Western eliminate the PAR and put purchase power costs back into the PRS and include the costs in the firm power rate.

Response: In its March 6, 2002, proposal, at the request of some firm power customers, Western removed all purchase power costs from the PRS and included the near-term purchase power costs in a PAR. The PAR was initially calculated at 2.6 mills/kWh. At its second Public Information Forum on April 23, 2002, the CRSP MC provided a revised calculation of the PAR at 5.1 mills/kWh. This revision reflected updated reservoir conditions which resulted in increased purchased power needs for the next 2 years. The PAR would be subject to further revisions, depending upon hydrological projections at the time of the rate order submission.

The CRSP MC received an overwhelming number of comments and concerns expressed by the customers concerning the PAR. The CRSP MC has made the decision to eliminate the PAR and include purchase power expenses in the Rate-Setting PRS when calculating the firm power rate. Western has not included additional comments received regarding the PAR calculation since it has determined to eliminate the PAR.

2. Purchase Power

A. *Comment:* Customers suggest that Western reconsider its approach in determining purchase power costs for the PRS, at least in the early years, to recognize the near-term hydrology, depleted reservoirs, and Western's commitment to deliver all energy in excess of SHP to its customers at the firm power rate. Customers further recommend that Western determine purchase power projections in a manner similar to that under Rate Schedule SLIP-F6 (current rate schedule). Customers recommend that Western determine rates consistent with its historical methodologies. The customers also desire to work with Western to determine the adequate amount of purchases that should be included in the rate-setting PRS.

Response: The CRSP MC recognizes the current dry hydrological conditions and subsequent depleted reservoirs and has attempted to reflect this in the purchase power estimates. The near-term purchases are based on Reclamation's 24-month hydrological study for FY's 2003 and 2004 and average hydrology for the remainder of the rate-setting years.

B. *Comment:* Several customers suggest Western use average hydrology to project purchase power in the PRS. Customers believe this conforms to the Post-1989 Marketing Criteria and is consistent with historic and current treatment in the PRS. In particular, some customers also commented on the May 2, 2002, data provided regarding average hydrology, which indicated purchases of $42 million in FY 2002 and no purchases in FY 2004 through 2007 to support their position on the use of hydrology.

Response: The CRSP MC has used Reclamation's 24-month hydrological study for projecting purchase power costs in FY's 2003 and 2004. Beyond those years, the CRSP MC used average hydrology in projecting purchase power costs in the long-term.

The data provided May 2, 2002, was an estimate developed for discussion purposes only. The CRSP MC further updated its analysis of average hydrology, which indicates purchases are needed throughout the Rate-Setting PRS.

C. *Comment:* To the extent it is allowed by law and regulation, a customer recommended that Western use physical as well as financial risk mitigation methods to minimize the rate risk. As part of this, customers suggest that Western, to the extent it is not prohibited by law and/or regulation, evaluate using hydro availability hedges.

Response: Western is open to considering such possibilities which would limit its risk. Western does have Federal laws, regulations, etc., that need to be taken into consideration, depending on the details of customer suggestions.

D. *Comment:* A customer suggests that Western use an 11 percent loss factor at Glen Canyon when determining energy available for purchase power projections.

Response: The purchase power projections reflect an 11 percent loss factor at Glen Canyon and 5.5 percent at other SLCA/IP generating units. Assuming that 70 percent of SLCA/IP generation comes from Glen Canyon Power Plant, the average loss factor applied is 9.35 percent.

E. *Comment:* Western received a small number of comments regarding various alternatives for assessing purchase power costs. These proposals include: (1) Western should allow its preference power customers to make a decision to temporarily reduce their SHP entitlements, (2) Western should develop rate-based alternatives such as a ''slice of the system,'' possibly under conditions of low hydrology or high purchase power expense, and (3) Western should provide a more flexible situation where additional firming purchases are a customer decision, rather than solely Western's. A customer wants assurance that the revised rate will provide for delivery of full SHP.

Response: Based on the large number of comments Western received suggesting that it should not implement a PAR and include purchased power costs in the firm power rate, Western has decided to include purchases in the Rate-Setting PRS in developing the firm energy and capacity rates. On October 1, 2002, Western expects to begin providing the contractually obligated capacity and energy as provided for under the Post-1989 Marketing Plan and what is commonly referred to as Contract Amendment No. 4.

3. O&M

A. *Comment:* Customers support inclusion of Western's FY 2004 Work Plan O&M budgets, but believe it is premature to include Reclamation's FY 2004 Work Plan O&M budgets.

Response: Based on customers' requests, Western included its FY 2004 Work Plan in the Rate-Setting PRS. For consistency purposes, Western believes that it is appropriate to also include Reclamation's FY 2004 Work Plan. Western believes that both agency Work Plan documents are in similar stages of development, and have been made available for customer review.

B. *Comment:* A customer is concerned that CRSP is only reducing by 5 percent its budget request for FY 2003, rather than the 10 percent the other Western regions appear to be receiving in FY 2003.

Response: The DOE, in an effort to shift its priorities more toward domestic security, has asked agencies such as Western to reduce FTE and thereby appropriations. Other budget items such as operation, maintenance, replacements, and emergency expenditures, were not reduced; therefore, the overall CRSP reduction was 5 percent.

C. *Comment:* Customers suggest that Western and Reclamation further review the OM&R and capital costs for FY 2003 and FY 2004 and aggressively pursue opportunities to reduce or defer costs beyond the rate-setting window.

Response: Western will continue to pursue cost reduction opportunities; however, it must also satisfy the need to provide a reliable system. Western believes that the Work Program Review process that it conducts with its customers has been beneficial in reducing both Reclamation and Western's O&M.

D. *Comment:* A customer wants to know how the allocation from other Western Regions impacted the budget projections after Transformation.

Response: Overall costs decreased following Transformation as Western reduced FTE, with a major reduction coming from CRSP.

As part of the reorganization, most of the O&M functions of the CRSP MC were moved to Western's RMR and DSWR. There were some costs in the other Western Regions that were appropriate to be allocated to CRSP that had not been anticipated in the FY 1998 budget, which the existing firm power rate is based upon. An example of this is the allocation to CRSP for a portion of a region's facility costs and capitalized SCADA costs.

E. *Comment:* A customer wants an explanation of the significant increase in costs of the Reclamation offices. As part of this, the customer wants to know what power program services costs became allocated to power.

Response: In the proposed rate, Reclamation has allocated costs associated with CRSP O&M costs of Upper Colorado River Basin offices to power based on their allocated, multipurpose, cost-share percentages. These percentages are described in the Reclamation Report on Allocation of Costs for the Colorado River Storage Project, dated December 1974. Reclamation's offices allocate O&M costs to various projects, such as CRSP. The costs that are directly charged to CRSP are further allocated to various purposes, such as power. The following provides power's percentage share of these that are charged to CRSP:

Ninety-two percent of the charges to CRSP from the Regional Office in Salt Lake City, Utah, are included in the Rate-Setting PRS. The Regional Office operates the mainstream reservoirs, including forecasting flow recommendations, coordination of conflicting multiple uses, and meeting legal requirements.

Ninety percent of the charges to CRSP from the Provo Office in Provo, Utah, are included in the Rate-Setting PRS. The Provo Office provides assistance associated with the operation of Flaming Gorge Dam including coordination of release requirements.

Ninety-seven percent of the charges to CRSP from the Grand Junction Office in Grand Junction, Colorado, are included in the Rate-Setting PRS. This office provides assistance on water operations and O&M activities for the Curecanti Unit.

Ninety-seven percent of the charges to CRSP from the Denver Power Office in Denver, Colorado, are included in the Rate-Setting PRS. The Denver Power Office provides support with the Power Program Services Division and O&M support of CRSP facilities.

Although the allocated share of CRSP costs allocated to power in these offices is between 90 and 100 percent, this amounts to only a small share of the total costs incurred by these offices for all of their project needs. For example, 5.6 percent of the Regional Office cost is a direct charge to the CRSP Project. Of those costs, 92 percent is allocated to power.

F. *Comment:* Customers request that Western not include the budgets for the proposed A-LP transmission line and switchyard. Customers encourage Western to consider potential rate impacts prior to including new projects in its work plans.

Response: The total budgeted costs for the proposed transmission line and switchyard are approximately $6 million from FY 2002 through FY 2006. This has a .07 mills/kWh impact on the firm power rate. Western will continue to include these costs in the Rate-Setting PRS as long as these costs are reflected in its budgets.

G. *Comment:* Customers suggest Western consider the potential outcome of legislation on the treatment of Federal Civil Service Retirement System (CSRS) costs and remove those costs from the PRS.

Response: The DOE General Counsel stated by memorandum dated July 1, 1998, the Power Marketing Administrations (PMAs) have the authority to collect, through the rates, the full costs of the retirement benefits. In addition, FERC has issued numerous orders approving the inclusion of such costs in PMA rates: Western Area Power Administration (Boulder Canyon Project), 96 FERC ¶ 61,171 (2001), Western Area Power Administration (Central Valley Project), 96 FERC ¶ 62,150 (2001), Southeastern Power Administration, 91 FERC ¶ 61,272 (2000), Western Area Power Administration (Intertie Project), 87 FERC ¶ 61,346 (1999), and Southeastern Power Administration, 86 FERC ¶ 61,195 (1999). Therefore, Western believes it should continue to include these costs in the Rate-Setting PRS.

If pending legislation addressing Federal retirement and health benefit costs is enacted into law, Western will assess the impact of that law on its decision to include these costs in the Rate-Setting PRS.

H. *Comment:* A customer wants to understand how the Western Electricity Coordinating Council (WECC) dues are broken out by the various projects.

Response: WECC assesses dues by control area and the amount of load in the control area. Western Area Colorado Missouri (WACM) and Western Area Lower Colorado (WALC) control areas both receive an assessment from WECC, and CRSP has loads in both control areas. The control areas break down the recovery by loads and bill the loads directly for their portion of the bill, based on their proportional share of the load. For firm electric service, Western pays for that portion of the load at each Federal delivery point, and the remainder is recovered through billing the load directly.

I. *Comment:* Customers request that Western not include the Common Electronic Scheduling System budgeted for in its FY 2004 Work Plan. Customers believe that these items should not be included in the PRS until the operational benefits associated with the investment are quantified.

Response: The Common Electronic Scheduling System costs are not included in the projected revenue requirement. Once Western purchases the system, the costs will be added to the CRSP CME. Then, depreciation charges are assessed against the total amount of CRSP CME. The sum of the depreciation charges is recorded annually in the PRS as an O&M expense. The Rate-Setting PRS projects CME depreciation costs based upon historical charges.

J. *Comment:* Several customers suggest that Western make security costs non-reimbursable as has the Department of the Interior.

Response: Western recognizes that Reclamation has made a determination that the security expenses funded by

Public Law 107–117, ''for emergency expenses to respond to the September 11, 2001, terrorist attacks,'' are to be considered non-reimbursable. Western has not received any appropriations to respond to post-September 11 security concerns. If Western does, it will make a determination at that time regarding the reimbursability of the expenses.

4. CUP

A. *Comment:* Customers support Western and Reclamation's agreement not to include certain CUP costs within the PRS, which resulted in approximately 2 mills/kWh savings. Several customers request that Western eliminate the CUP irrigation repayment costs from the PRS. Customers suggest that Western does not need to proceed with a rate adjustment at this time. Customers believe that there is significant ''cushion'' in the PRS due to an expected change in the CUP purposes from agricultural to municipal and industrial uses, which the customers believe will cause a major reduction in the CRSP rate. Customers believe that the CUP is the ''driver'' of the apportionment. Customers encourage timely completion of the revised DPR and cost allocations.

Response: There are $149.8 million of costs attributable to completion of the Bonneville Unit that have not met the criteria set forth by a 1983 agreement between Reclamation and Western and, therefore, are not included in the SLCA/IP firm power rate base. In FY 2001, $34.7 million of these costs met the 1983 agreement criteria which allows for these construction dollars to be included in the Rate-Setting PRS. However, these costs were not included, because of the potential change in the revised draft DPR and cost allocations. In December 2001, Western and Reclamation signed an agreement with the CUP Completion Act Office that the amount ($536.6 million) that was currently in the Rate-Setting PRS for the Bonneville Unit not be revised until the CUP Completion Act Office approves a draft supplement to the 1988 DPR.

It is expected that this draft supplement will be available in late FY 2003. At that time, Western, Reclamation, and the CUP Completion Act Office will discuss the implications of the change in the irrigation costs to be repaid by the power users. It is unknown what the rate impact of the draft supplement will be on the firm power rate. Until a draft supplement is completed, Western will continue to include the CUP irrigation repayment costs in the Rate-Setting PRS in accordance with the agreement between Western and Reclamation.

B. *Comment:* A customer wants to know why 10 years is being used for the Bonneville Unit power investigation costs amortization period. Several customers request that Western remove from the PRS the $12.6 million of ''sunk'' power investigation costs for the Bonneville Unit of the CUP. A customer argues that these costs should not be included in accordance with RA 6120.2, which states that expenditures booked to construction accounts become part of the rate analysis when the asset is placed in service. Customers cite the pending Federal legislation to make these costs non-reimbursable as cause to exclude these costs from the PRS.

Response: The Rate-Setting PRS amortizes these costs over a 10-year period without interest. Western's independent auditors suggested using a 10-year period because it lessened the impact to the customers as opposed to expensing this amount in a single year. Western believes that the $12.6 million, which is without interest during construction or interest in investment expenses, of power investigation costs should not be recognized as construction costs. Rather, these costs are considered investigation costs and not construction costs and, therefore, need to be recovered. Western is aware of the pending Federal legislation that potentially changes these costs to a non-reimbursable treatment. If this legislation is passed, Western will remove these costs from the financial statements and the PRS.

5. Outstanding Issues

A. *Comment:* A customer requests that the pending issues of reconstructing CRSP investments, accounting for system losses, deferred costs of the Bonneville unit completion and the A-LP, and Glen Canyon cost allocations under the GCPA be resolved and reflected in the rate as much as possible.

Response: The CRSP MC will continue to work on resolving these outstanding issues. Once the issues are resolved, the CRSP MC will reflect its resolution in the PRS. None are expected to have a major impact on the firm power rate. In accordance with RA 6120.2, Western will continue to perform yearly PRSs to determine if the rate is sufficient to meet all required payments.

B. *Comment:* Customers recognize that the outstanding issue of ''CRSP Reconstruction of Investment'' is internal to Western and request that the scenario that Western believes will most likely occur be included in the PRS.

Response: At the time of this rate order, Western is uncertain of the final resolution of this issue. There remains an amount of internal review regarding this issue. Therefore, the CRSP MC believes it is premature to speculate as to the likelihood or the extent of the potential resolution in the Rate-Setting PRS. Western will include the final determination in the PRS once a decision is made and the dollar amount is recorded in the audited financial statements.

C. *Comment:* A customer wants to know the status of the determination of non-reimbursability of Aspinall and Flaming Gorge studies which are budgeted by Reclamation.

Response: Flaming Gorge and Aspinall studies associated with the RIP are considered non-reimbursable. Costs associated with preparing an Environmental Impact Statement at Flaming Gorge, Aspinall, and Navajo have been determined by Reclamation to be partially non-reimbursable. Reclamation will continue to evaluate the costs of environmental studies at Aspinall, Flaming Gorge, and Navajo to determine if there is any justification to change the status of all of these expenses to non-reimbursable.

6. Merchant Function Revenues

A. *Comment:* Customers expressed concern over the revision which decreased the Merchant Function revenue projection. A customer recognizes the aberration the 2001 data caused to the Merchant Function revenues. A customer believes that Western should go back to the original estimate of non-firm transmission and Merchant Function revenues.

Response: Because the historical data for Merchant Function and non-firm transmission revenues is quite volatile, Western chose to use a 5-year average of these revenues instead of the 3-year average initially proposed. Currently, in FY 2002, CRSP is experiencing a drastic reduction in Merchant Function and non-firm transmission revenues. The CRSP MC believes that placing too much emphasis on historic revenues stemming from volatile conditions that occurred in FYs 2000 and 2001 might be overstating future revenues for rate-making purposes. The FY 2002 projection is based on actual data through 2002.

B. *Comment:* Customers support Western's recalculation of non-firm transmission and Merchant Function revenue projections as being a reasonable approach.

Response: Western believes that the recalculation of both non-firm transmission and Merchant Function revenues based on 5 years of historical data instead of the 3 years originally proposed is a better estimate of future revenues.

C. *Comment:* A customer questions if Merchant Function revenue includes sales of AHP at current rate.

Response: Merchant Function revenues include revenue from purchases for resale activities and from transaction fees. These do not include any AHP revenues either historically or in the projection. Revenues from AHP sales are included historically as part of firm power sales revenues and are netted against future purchases.

D. *Comment:* A customer questions the costs of the Merchant Function activities on an annual basis. Customers question profitability and the viability of this function. A customer believes Merchant Function revenues should be increasing due to increased Merchant Function staff.

Response: Western believes that the $5.5 million of annual revenues forecasted more than offset the costs of this function. The activities solely related to the Merchant Function are approximately $1.3 million yearly. These costs include labor, programming support, computer costs, and building expenses. These are offset by transaction fee charges and by purchases-for-resale activities. The transaction fees are updated each FY to ensure recovery of Merchant Function activities performed for others.

7. Basin Fund

A. *Comment:* A customer suggests that Western devote more staff and attention to plan for and regularly update its cash reserve requirements, so customers and Western are not faced with Basin Fund cash flow concerns in the future. Customers encourage Western to maintain a reasonable Basin Fund level to accomplish project purposes and to work with its customers to maintain options to address Basin Fund cash flow constraints.

Response: Due to market volatility, recent drought conditions, and environmental test flows, the Basin Fund has been severely depleted of its available cash. As a result, the CRSP MC worked closely with its customers to find alternative solutions to remedy this situation. The CRSP MC is fully devoted and attentive to the cash balance in the Basin Fund and routinely performs cash flow analysis to help ensure the solvency of the Basin Fund. As part of the fiscal year end process, Western works in consultation with its customers and Reclamation in determining the appropriate level of cash balance for the following fiscal year. Western is obligated, under the CRSP Act, to annually return revenues in the Basin Fund in excess of operating needs to the General Fund of the Treasury.

B. *Comment:* A customer expressed concern that the CRSP MC's management of a collaborative process is flawed. A customer cites example of customer's assistance in receiving a ''slice'' to help build the Basin Fund level to reasonable levels. This customer is concerned that now that the Basin Fund level is at a reasonable level, Western is proposing to return to providing the full contract commitment and will no longer continue providing a ''slice,'' even at customers' requests.

Response: The CRSP MC believes in the benefits of a collaborative process. Unfortunately, it is not always able to achieve an optimal resolution for Western and its customers.

C. *Comment:* Customers encourage Western to consider other options to alleviate immediate cash flow pressures. Customers have significant concern about the impacts to Basin Fund cash flows resulting from non-reimbursable expenses, primarily associated with environmental programs.

Response: Western continues to be open to options which assist in alleviating cash flow constraints. When the Basin Fund provides for non-reimbursable expenses, it reduces the amount of cash available for other expenditures within the Basin Fund. The non-reimbursable costs are primarily a result of environmental programs under the GCPA and the RIP.

Section 1807 of the GCPA, states that: ''The Secretary is authorized to use funds received from the sale of electric power and energy from the Colorado River Storage Project to prepare the environmental impact statement, described in Section 1804, including supporting studies, and the long-term monitoring programs and activities described in Section 1805. Except, funds will be treated as having been repaid and returned to the General Fund of the Treasury as costs assigned to power for repayment under Section 5 of the CRSP Act.'' This legislation allows for, but does not mandate, the use of power revenues for these purposes. Western has informed the Adaptive Management Work Group that should funds not be available to conduct an experiment, Western will work with Reclamation and others to obtain alternative sources of funds.

The Recovery Implementation Program legislation, Pub. L. 106–392, Section 3(d)(3)(2) provides that: ''If Western Area Power Administration and the Bureau of Reclamation determine that the funds in the Colorado River Basin Fund will not be sufficient to meet the obligations of section 5(c)(1) of the Colorado River Storage Project Act for a 3-year period, the Western Area Power Administration and the Bureau of Reclamation shall request appropriations to meet base funding obligations.'' This legislation provides Western with more flexibility in funding those costs. Western will notify Reclamation that alternative funding sources should be sought if Basin Fund projections indicate it to be insufficient.

D. *Comment:* A customer is opposed to the use of the PAR as the method to increase the level of the Basin Fund.

Response: The PAR was proposed to recover the cost of near-term purchase power costs only and was not designed to increase the level of the Basin Fund. The ''true-up'' component of the PAR formula was developed to ensure that firm power customers only paid for their actual purchased power costs.

E. *Comment:* Several customers expressed concern over the reduction in resources available at the firm power rate as a result of the reduced Basin Fund balance which was largely drawn down by environmental programs, below average hydrology, and high market prices for purchase power. Customers suggested this reduction in resources be taken into account when setting a new rate so that CRSP costs are not further exacerbated.

Response: Due to market volatility, recent drought conditions, and environmental test flows, the Basin Fund was severely depleted of its available cash. The Basin Fund balance reached a level that CRSP MC could no longer provide the cash for the firming purchases. As a result, the CRSP MC worked closely with its customers to find alternative solutions to remedy this situation. Western appreciates its firm power customers' assistance in this matter and recognizes the financial hardships to the customers due to market volatility and market conditions. The CRSP MC is establishing a firm power rate at the lowest possible rate consistent with sound business practices. This rate will allow the CRSP MC to return to including firming purchases to meet contract capacity and energy commitments in the firm power rate.

8. Miscellaneous

A. *Comment:* Several customers expressed concerns regarding decreased project use energy for A–LP and its impact on the firm power rate. Some customers questioned if this energy should be AHP.

Response: The total energy sales used to calculate the existing rate is different from the proposed rate due to the reduction in project use commitments. The energy used as the rate denominator is the sum of firm power and project use commitments. This difference is made available as AHP if Western has surplus generation, or it is used to reduce the amount of purchased power needs. Annually, Western experiences changes in the amount of total energy sales because of updated estimates for project use loads. For example, in the last rate process, the energy amount increased by 453 GWh because the contractual energy delivered was projected to increase throughout the rate-setting period.

B. *Comment:* Customers inquired if the PRS reflects the downsized A–LP in aid to irrigation amounts.

Response: The PRS currently includes no revenue requirements associated with the A–LP. The irrigation assistance requirements of the CUP and the provisions for the State of Colorado's apportionment as included in the CRSP Act provides more than enough revenue to Colorado for its planned irrigation development projects.

C. *Comment:* A customer wants to understand what non-reimbursable costs are excluded from the Rate-Setting PRS.

Response: All non-reimbursable costs are excluded from the Rate-Setting PRS. For Western, non-reimbursable costs excluded are RIP initiatives and purchased power costs for low-water monitoring studies pertaining to implementing the GCPA. This includes costs for some personnel at CRSP MC and the Corporate Services Office who perform activities related to the RIP and GCPA. RIP costs also include a contract with Argonne National Laboratories (DOE).

In Reclamation's budget, costs for the Glen Canyon Adaptive Management Program as well as the RIP base funding are considered non-reimbursable costs. Also excluded from the PRS because of non-reimbursability are such Reclamation costs as land resources management.

D. *Comment:* A customer wants assurance that Glen Canyon experimental flows are non-reimbursable.

Response: Glen Canyon experimental test flows occurred in FY 2000. The purchased power expense that was deemed to be non-reimbursable amounted to $21.5 million in FY 2000. These were a result of experimental flows and are reflected as non-reimbursable expenses in the Rate-Setting PRS. As stated in Section 1807 of the GCPA, ''All costs of preparing the environmental impact statement described in section 1804, including supporting studies, and the long-term monitoring programs and activities described in section 1805 shall be non-reimbursable.''

E. *Comment:* A customer wants to know when the FYs 2000 and 2001 audited financial data will be available.

Response: Western finalized the audited financial statements for FY 2000 in March 2002. Western expects to complete FY 2001 audited financial statements before the end of 2002.

F. *Comment:* A customer wants to know what is included in Miscellaneous Revenues.

Response: This category includes ancillary services, facility-use charges, administrative charges, auxiliary services, and other miscellaneous operating revenues.

G. *Comment:* Customers expressed concern that AHP revenues are not in the PRS.

Response: AHP sales result when Western has additional hydrogeneration above what is obligated to the firm power customer by contract. Revenue from these sales is reflected historically in the firm power revenues. In forecasting future years in the Rate-Setting PRS, this additional hydro is used to offset projected purchase power needs.

CRSP Transmission Discussion

A new rate methodology is being proposed that is more consistent with the methodology used at other Western regions and other utilities. The proposed methodology is an annual fixed charge formula that will be used to determine the revenue requirement to be recovered from transmission service. The annual transmission revenue requirement includes O&M expense, administrative and general expense, interest expense, and depreciation expense from the most recent historical test year. This transmission revenue requirement is offset by appropriate CRSP revenue credits.

The CRSP transmission system includes its own facilities and the transmission facilities owned by others over which the CRSP MC has contractual rights. All the costs of the CRSP transmission system, including the costs paid to others for the contractual rights on their transmission lines, are in the total CRSP transmission revenue requirement.

The provisional firm transmission rate will be applied to customers who purchase transmission services. The costs of CRSP firm transmission associated with the delivery of SLCA/IP firm power are included in the firm power rate.

The costs for providing scheduling, system control, and dispatch service are included in the appropriate provisional transmission services rates. Because the CRSP transmission system lies in two other Western Regions, the charges for reactive supply and voltage control service will be in accordance with each Region's applicable tariff.

The provisional transmission rate formulas are scheduled to go into effect October 1, 2002, to correspond with the effective date of the provisional firm power rate.

CRSP Transmission Rate

Point-to-Point

The current firm transmission rate expires March 30, 2003. The provisional rate for firm point-to-point CRSP transmission service for FY 2003 is $2.06 per kWmonth and will result in a 16 percent increase from the existing rate of $1.78 per kWmonth under Rate Schedule SP–PTP6, effective April 1, 2002. The provisional rate for non-firm CRSP transmission service is expressed in mills/kWh and is based on the current CRSP firm point-to-point rate, and may be discounted. The non-firm transmission rate for FY 2003 is 2.82 mills/kWh.

The proposed transmission rate methodology is different from the current transmission rate methodology, primarily in four areas. The first area is the basis for cost projections. In the current transmission rate calculation, the CRSP MC uses the average of 5-year projections. The provisional transmission rate is based on the most recent financial data from 1 year.

The second area is the allocating of Western's O&M costs in the revenue requirement that are allocable to generation and transmission. In the current transmission rate calculation, the CRSP MC determines the percentage of CRSP transmission investment relative to total CRSP Reclamation and Western investment and applies this percentage to projected Western CRSP O&M budgets. The provisional transmission rate is based on the percentage of Western's CRSP transmission investment to total Western CRSP investment, and this percentage is applied to Western's test year O&M costs.

The third area is the allocation of Western's capital costs attributable to both generation and transmission. In the current transmission rate calculation, the CRSP MC assigns these costs to generation and transmission on a 50/50 basis. In the provisional transmission rate calculation, Western has analyzed capital costs more closely and assigned them more specifically relative to transmission usage.

The fourth area is the annual recalculation of the formula. In the current transmission rate, the CRSP MC annually updates revenue credits and transmission capacity reservations and holds the annual revenue requirement constant. The provisional transmission rate recalculates all components of the formula annually as new test year data become available.

The increase in the CRSP firm transmission service rate is due to the gross transmission revenue requirement increasing. This increase is being offset by an increase in transmission revenue credits and in firm wheeling reservations.

This table summarizes the difference in calculations between the current transmission rate and the provisional transmission rate. The table compares the change in the average annual projections used in the FY 2002 transmission study (which set the rate effective April 1, 2002) and the annual projections used in the rate-setting transmission study for this rate adjustment.

COMPARISON OF ANNUAL REVENUE REQUIREMENTS

Item	Unit	Existing rate	Provisional rate	% Change
Annual Revenue Requirement	$	63,271,051	77,134,227	22
Transmission Revenue Credits	$	8,302,800	11,854,759	43
Net Annual Revenue Requirement	$	54,968,215	65,279,468	19
Firm Obligations	kW	2,134,792	2,226,740	4
Firm Point-to-Point Transmission Contracts		442,420	444,132	1
Network Integration Loads		0	0	
Transmission System Total Load	kW	2,577,212	2,640,341	2
Cost per Year	$	21.33	24.72	16
Cost per Month	$	1.78	2.06	16

The increase in annual Revenue Requirements is primarily a result of a revised methodology and increased O&M expenses. The increase in transmission credits is primarily a result of increased non-firm transmission and ancillary service revenues. The increase in firm power obligations is primarily a result of applying test year data instead of a 5-year average.

Network

The same revenue requirement that was used in determining the provisional firm point-to-point transmission rate will also be used in the provisional rate formula for network integration transmission service. The provisional charge for the monthly demand for network integration transmission service will be the product of the network customer's load ratio share times one-twelfth ($1/12$) of the annual transmission revenue requirement. The load ratio share will be based on the network customer's hourly load (including its designated network load not physically interconnected with Western), coincident with CRSP's monthly transmission system peak, which will be calculated on a rolling 12–CP basis. Western's transmission system peak includes the sum of capacity reserved for point-to-point transmission, 12–CP monthly entitlements for SLCA/IP firm power customers, and the average 12–CP monthly system peak for network transmission service. The provisional rate formula is to be effective for the period beginning October 1, 2002, through September 30, 2007.

Basis for Rate Development

The existing rates for CRSP firm and non-firm transmission in Rate Schedules SP–PTP5, SP–NW1, and SP–NFT4 expire March 30, 2003. The rate adjustment contains rates that replace existing rates. The adjusted rates reflect a revised methodology and increases in O&M costs, revenue credits, and transmission system load. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period. The provisional rates will take effect on October 1, 2002, to correspond with the start of the Federal fiscal year and will remain in effect through September 30, 2007.

The provision for reactive power adjustment is part of the provisional rates for CRSP firm and non-firm transmission. The provisions and methodologies for this adjustment are not being modified and will remain as specified in SP–PTP5, SP–NW1, and SP–NFT5.

The adjustment for losses provision contained in Rate Schedules SP–PTP5, SP–NW1, and SP–NFT5 will remain the same and also include a statement to allow for financial compensation to recover losses.

The proposed rates for CRSP transmission include a provision to pass through electric industry restructuring costs associated with providing transmission service. These costs will be passed through to each appropriate transmission customer.

Comments

The comments and responses regarding the transmission rates, 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:* A customer inquired if there is an additional methodology to reconcile between the old method and the proposed transmission method in terms of revenues collected.

Response: Western has proposed a revised methodology for determining a rate to charge for transmission service. Any costs that are not included in the transmission revenue requirement are in the firm power revenue requirement. The firm power rate includes both transmission and power revenue requirements for firm power customers and reflects the revenues from firm and non-firm transmission as an offset. Therefore, the reconciling or balancing occurs in the firm power rate.

B. *Comment:* A customer requested an explanation of the change in the components of the transmission rate denominator from the transmission rate effective April 1, 2001, to the proposed rate.

Response: The April 1, 2001, rate included the (1) 1–CP firm power contract commitments, (2) 130,000 kW of Merchant Function reservation, (3) 250,000 kW for the Salt River Project

Exchange, and (4) 406,446 kW for firm transmission reservations.

The provisional transmission rate includes the (1) 12–CP of firm power contract commitments, (2) 555,000 kW of Merchant Function reservation, (3) 250,000 kW for the Salt River Project Exchange, and (4) 444,132 kW for firm transmission reservations.

C. *Comment:* A customer requested an explanation of the impact of the Reclamation investment exclusion in transmission O&M.

Response: The existing transmission rate methodology allocates Western budgeted O&M based on the relationship between Western transmission investment to total Western and Reclamation investment. The proposed method allocates Western's test year O&M based on CRSP transmission investment to total CRSP investment and does not include Reclamation investment. More of Western's O&M expenses are allocated to transmission under the proposed methodology.

D. *Comment:* A customer wanted to know if multi-project cost allocations impact the CRSP transmission amount included in the rate formula.

Response: The CRSP transmission rate includes test year O&M expenses for Western's CRSP MC, DSWR, and RMR offices. O&M expenses are derived consistently with how these are budgeted, which is based on appropriate cost allocation, *e.g.* multi-project. Therefore, multi-project cost allocations do have an impact on the CRSP transmission rate.

E. *Comment:* A customer requested an explanation of the ''adjustment for industry restructuring'' and questioned if this clause was included in the existing rate schedule.

Response: As discussion about Regional Transmission Organizations, Independent Transmission Companies, and Independent System Operators continues, Western is concerned that, if it joins such a group, the costs to join groups such as these be recovered through the transmission rate and that such recovery of costs could be delayed with substantial costs accruing. Furthermore, these costs (such as scheduling and dispatch) may not be allocable to all transmission customers. Therefore, the adjustment will allow Western to pass through those costs as they occur to the appropriate customer. Inasmuch as these costs are reflected as O&M expenses, Western will ensure that these costs are not being accounted for twice.

F. *Comment:* A customer wanted to know how current the 9.10-percent fixed charge rate is in the Supporting Documentation. The customer wanted to know when the FY 2000 data will be available.

Response: The fixed charge rate is a percentage calculation applied to the net transmission investment to derive an annual transmission revenue requirement. The 9.10 percent is the amount of interest charge listed in the Supporting Documentation. The fixed charge rate listed is 23.57 percent. This is based on FY 1999 data.

The FY 2000 data became available in early March 2002. The 9.10-percent interest charge and the annual fixed charge rate have changed as a result of incorporating FY 2001 data as the test year. These amounts are now 9.55 percent for the interest charge, and 25.17 percent for the annual fixed charge rate.

G. *Comment:* A customer believes there is a difference in transmission rates between the firm transmission and firm power customers. Firm power customers are assessed a constant bundled rate; firm transmission customers are assessed the rate that is developed annually. The customer wants to understand how the annual transmission rate changes impact the power repayment study.

Response: The calculation for delivery to Firm Electric Service customers is on the same basis as for other firm transmission customers. The transmission rate denominator reflects the use of the CRSP transmission system by all parties, including the CRSP Merchant Function and Firm Electric Service customers. The same costs are applied to both transmission and firm power customers using the CRSP transmission system.

The CRSP MC prepares a power repayment study annually. As part of this, a projection of firm transmission revenues and all costs of transmission service are included. These firm transmission revenues are based on the transmission rate then in effect. If the annual recalculation of the transmission rate results in a change in the forecast and if no other changes in the power repayment study occur, a revision to the firm power rate will likely be needed. However, because the transmission costs of the firm power customers are only one component of the bundled service and many other components of the power repayment study are changing and may offset the impact of a firm transmission rate change, a firm power rate change may not be necessary.

H. *Comment:* A customer wanted to know if Western offers Network Service.

Response: CRSP is not currently providing Network Service to any transmission customers. Once Western receives a request for this service, a study would be conducted to determine its feasibility.

Ancillary Services Discussion

On April 1, 1998, the Western Area Upper Colorado control area, within which most of the CRSP transmission system lies, operated by the CRSP MC, was merged into two other control areas. These control areas are WACM, operated by Western's RMR, and WALC, operated by Western's DSWR.

Six transmission ancillary services will be offered by the CRSP MC. These are (1) scheduling, system control, and dispatch service, (2) reactive supply and voltage control service, (3) regulation and frequency response service, (4) energy imbalance service, (5) spinning reserve service, and (6) supplemental reserve service. The first two—scheduling, system control, and dispatch service; and reactive supply and voltage control service—are required services. The remaining four will also be offered from the control area or from the CRSP Merchant Function. These ancillary services are listed in Western's Tariff.

Western's use of SLCA/IP resources to provide sales of ancillary services is subject to availability. Western has allocated most of its SLCA/IP power resources to preference entities under long-term commitments. Western will determine if any of its SLCA/IP resources are available to provide the ancillary service requested at the time of the request.

The provisional rates for ancillary services are designed to recover only the costs associated with providing the service(s). The costs for providing scheduling, system control, and dispatch service are included in the provisional transmission service rates. The provisional rates and descriptions for the six ancillary services are:

PROVISIONAL ANCILLARY SERVICES RATES

Ancillary service type	Ancillary service description	Provisional rate
Scheduling, System Control, and Dispatch	Required to schedule the movement of power through, out of, within, or into a control area.	Included in appropriate transmission rates.
Reactive Supply and Voltage Control	Reactive power support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.	DSWR rate schedule—DSW–RS1, or RMR rate schedule—L–AS2, or as superseded.
Regulation and Frequency Response	Generation provided to match resources and loads on a real-time continuous basis.	If available from SLCA/IP resources, the firm capacity rate will apply. If unavailable, DSWR rate schedule—DSW–FR1, or RMR rate schedule—L–AS3 or as superseded will apply.
Energy Imbalance	Provided when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single hour.	DSWR rate schedule—DSW–EI1, or RMR rate schedule—L–AS4 or as superseded, or the customer can make alternative comparable arrangements.
Spinning Reserve	Needed to serve load immediately in the event of a system contingency.	Based on terms and conditions of WSPP contract.
Supplemental Reserve	Needed to serve load in the event of a system contingency; however, it is not available immediately to serve load, butof rather within a short period of time.	Based on terms and conditions WSPP contract.

Comments

The comments and responses regarding ancillary service rates, 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.

Comments

A. *Comment:* A customer wanted to know where regulation services come from that go to WACM.

Response: CRSP resources provide 20 MW to the WACM control area to regulate SLCA/IP firm electric service loads in that control area. WACM uses its own resources to provide regulation to its customers.

B. *Comment:* A customer questioned the role of Western's control area consolidation in causing the increase in losses.

Response: Western is still examining this issue and believes that the increase in the Glen Canyon loss factor from previous amounts is likely due to several factors, one of which is increased use of the CRSP transmission system.

CRSP MC has recently reduced the losses applied in determining available generation from 11 percent from all generators to 5.5 percent, with the exception of Glen Canyon which remains at 11 percent. The average loss factor applied equates to 9.35 percent.

C. *Comment:* A customer questioned if CRSP is being fairly compensated for ancillary services. The customer requested assurance that ancillary services are appropriately credited to the Basin Fund from other regions.

Response: The CRSP MC revenue requirements for ancillary services are used to calculate rates for ancillary services in each particular region. Accounting mechanisms have been put into place to track these revenues. Since 1998, the CRSP MC has received approximately $8 million into the Basin Fund from ancillary service revenues.

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.

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.

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.

Availability of Information

Information about this rate adjustment, including power repayment studies, 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 Colorado River Storage Project Management Center, Western Area Power Administration, 150 East Social Hall Avenue, Suite 300, Salt Lake City, Utah.

Submission to the Federal Energy Regulatory Commission

The interim 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 pursuant to the authority delegated to me, I confirm and approve on an interim basis, effective October 1, 2002, Rate Schedules SLIP–F7, SP–PTP6, SP–NW2, SP–NFT5, SP–SD2, SP–RS2, SP–EI2, SP–FR2, and SP–SSR2 for the Salt Lake City Area Integrated Projects and the

Colorado River Storage Project of the Western Area Power Administration. 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 September 30, 2007.

Dated: September 10, 2002.

Spencer Abraham,

Secretary.

Salt Lake City Area Integrated Projects; Arizona, Colorado, Nevada, New Mexico, Utah, Wyoming; Schedule of Rates for Firm Power Service

Effective: The first day of the first full billing period beginning on or after October 1, 2002, and extending through September 30, 2007, or until superseded by another rate schedule, whichever occurs earlier.

Available: In the area served by the Salt Lake City Area Integrated Projects.

Applicable: To the wholesale power customer for firm power service supplied through one meter at one point of delivery, or as otherwise established by contract.

Character and Conditions of Service: Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract.

Monthly Rates: Demand Charge: $4.04 per kilowatt of billing demand.

Energy Charge: 9.5 mills per kilowatthour of billing energy.

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 more than, the delivery obligation under the power sales contract, or

2. The Contract Rate of Delivery.

Billing Energy: The billing energy will be the energy measured during the month up to, but not more than, the delivery obligation under the power sales contract.

Adjustment for Transformer Losses: If delivery is made at transmission voltage but metered on the low-voltage side of the substation, the meter readings will be increased to compensate for transformer losses as provided for in the contract.

Adjustment for Power Factor: The customer will be required to maintain a power factor at all points of measurement between 95 percent lagging and 95 percent leading.

Adjustment for Western Replacement Power: Pursuant to the Contractor's Firm Electric Service Contract, as amended, Western will bill the Contractor for its proportionate share of the costs of Western Replacement Power (WRP) within a given time period. Western will include in the Contractor's monthly power bill the cost of the WRP and the incremental administrative costs associated with Western Replacement Power.

Adjustment for Customer Displacement Power Administrative Charges: Western will include in the Contractor's regular monthly power bill the incremental administrative costs associated with Customer Displacement Power.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rate for Firm Point-to-Point Transmission Service

Effective: The first day of the first full billing period beginning on or after October 1, 2002, and extending through September 30, 2007, or until superseded by another rate schedule, whichever occurs earlier.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To firm point-to-point transmission service customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service: Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Point-to-Point Rate Formula: The firm point-to-point rate is based on a test year using an annual fixed charge methodology. The test year is the most recent historical data available. The annual revenue requirement is reduced by revenue credits. The resultant net annual cost to be recovered is divided by the capacity reservation needed to meet firm power and transmission commitments in kW, including the total network integration loads at system peak, to derive a cost/kWyear. The cost/kWyear is calculated using the following formula:

$$1.\quad ARR - TRC = NARR$$

$$2.\quad \frac{NARR}{TSTL}$$

Where:

ARR = Annual Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expense, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary service revenues and phase shifter revenues, and excluding long-term firm transmission revenues.

NARR = NetAnnual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

TSTL = CRSP Transmission System Total Load. The sum of the total CRSP transmission capacity under the long-term reservation plus the total network integration loads at system peak.

This formula will be recalculated annually by applying the data from the most current historical test year. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective.

The rate for transmission service includes scheduling, system control, and dispatch. Rate Schedule SP-RS2, or any superseding rate schedule, for reactive supply and voltage control is attached as part of this Rate Schedule and applies to firm point-to-point transmission customers.

Billing: The point-to-point transmission customer will be billed monthly by applying the resulting rate to the maximum amount of capacity reserved, payable whether used or not, except as otherwise provided in existing contracts.

Requirements for Reactive Power: Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustment for Losses: Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer as established by contract. If losses are not fully provided by a transmission customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring: Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission customer, as appropriate.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Monthly Charge Calculation for Network Integration Transmission Service

Effective: The first day of the first full billing period beginning on or after October 1, 2002, and extending through September 30, 2007, or until superseded by another rate schedule, whichever occurs earlier.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To network transmission service customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service: Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Monthly Network Formula: The network integration transmission service charge will be the product of the network customer's load ratio share times one twelfth (1/12) of the total net annual transmission revenue requirement. The same Net Annual Transmission Revenue Requirement is used in determining the rate for network transmission service as for point-to-point transmission service. It is based on a test year using an annual fixed charge methodology. The test year is the most recent historical data available. The annual revenue requirement is reduced by revenue credits. The formula is as follows:

$$1.\ \text{ARR} - \text{TRC} = \text{NARR}$$

$$2.\ \frac{\text{NARR}}{12} \times \text{Transmission Customer's Load-Ratio Share}$$

Where:

ARR = Annual Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expense, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary services revenues and phase shifter revenues, and excluding long-term firm transmission revenues.

NARR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

Load-Ratio Share = Network customer's hourly load (including its designated network load not physically interconnected with Western) coincident with Western's monthly CRSP transmission system peak.

This formula will be recalculated annually by applying the data from the most current historical test year. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective.

The monthly charge for network transmission service includes scheduling, system control, and dispatch. Rate Schedule SP-RS2, or any superseding rate schedule, will be attached as part of this Rate Schedule and applies to network transmission customers.

Billing: Billing determinants for the formula rate above will be as specified in the service agreement.

Requirements for Reactive Power: Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustment for Losses: Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer as established by contract. If losses are not fully provided by a transmission customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring: Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission customer, as appropriate.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rate for Non-Firm, Point-to-Point, Transmission Service

Effective: The first day of the first full billing period beginning on or after October 1, 2002, and extending through September 30, 2007, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To non-firm, point-to-point, transmission service customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system as established by contract.

Character and Conditions of Service: Transmission service on an interruptible basis for three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery specified in the service contract or in advance by the Western Area Power Administration (Western). Conditions for curtailment shall be determined by Western and in accordance with Western's Tariff.

Rate: The proposed rate for non-firm, point-to-point, CRSP transmission service is based upon the firm point-to-point rate expressed in mills/kWh. This rate may be discounted.

Billing: The rate will be applied to each kWh delivered at the point of delivery, as specified in the service contract.

Adjustments for Reactive Power: None. There shall be no entitlement to transfer of reactive kilovolt-amperes at delivery points, except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustments for Losses: Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract. If losses are not fully provided by a transmission customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring: Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission customer, as appropriate.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rates for Scheduling, System Control, and Dispatch Ancillary Service

Effective: Beginning on October 1, 2002, and extending through September 30, 2007.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To all CRSP transmission customers receiving this service.

Character of Service: Scheduling, System Control, and Dispatch is required to schedule the movement of power through, out of, within, or into a control area.

Rate: Included in appropriate transmission rates.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rate for Reactive Supply and Voltage Control Ancillary Service

Effective: Beginning on October 1, 2002, and extending through September 30, 2007.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To all CRSP transmission customers receiving this service.

Character of Service: Reactive power is support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.

Rate: Provided through WALC under Rate Schedule DSW–RS1 or WACM under Rate Schedule L–AS2, or as superseded.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rates for Energy Imbalance Ancillary Service

Effective: Beginning on October 1, 2002, and extending through September 30, 2007.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To all CRSP transmission customers receiving this service.

Character of Service: Provided when a difference occurs between the schedules and the actual delivery of energy to a load located within a control area over a single hour.

Rates: Provided through WALC under Rate Schedule DSW–E1 or WACM under Rate Schedule L–AS3, or as superseded, or the customer can make alternative comparable arrangements to satisfy its Energy Imbalance service obligations.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rate for Regulation and Frequency Response Ancillary Service

Effective: Beginning on October 1, 2002, and extending through September 30, 2007.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To all CRSP transmission customers receiving this service.

Character of Service: Necessary to provide for the continuous balancing of resources, generation and interchange, with load and for maintaining schedules interconnection frequency at sixty cycles per second (60 Hz).

Rate: If the CRSP MC has regulation available for sale, the SLCA/IP firm power capacity rate, currently in effect, will be charged. If regulation is unavailable from SLCA/IP resources, the WALC or WACM control areas can provide the service, in accordance with their respective rate schedules.

Colorado River Storage Project; Arizona, Colorado, Nevada, New Mexico, Utah; Schedule of Rates for Spinning and Supplemental Reserve Ancillary Service

Effective: Beginning on October 1, 2002, and extending through September 30, 2007.

Available: In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable: To all CRSP transmission customers receiving this service.

Character of Service: Spinning Reserve is defined in Schedule 5 of Western Area Power Administration's Open Access Transmission Tariff.

Supplemental Reserve is defined in Schedule 6 of Western Area Power Administration's Open Access Transmission Tariff.

Rate: The transmission customer serving loads within the transmission provider's control area must acquire Spinning and Supplemental Reserve services from Western, from a third party, or by self supply. If the CRSP MC provides these services, the rates under the Western Systems Power Pool contract will apply.

[FR Doc. 02–24424 Filed 9–25–02; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7383–3]

Agency Information Collection Activities: Request for Comments on Fourteen Proposed Information Collection Requests (ICRs)

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 that EPA (the Agency) is planning to submit the fourteen continuing Information Collection Requests (ICRs) listed in Section A of this notice to the Office of Management and Budget (OMB). Before submitting the ICRs to OMB for review and approval, EPA is soliciting comments on specific aspects of the information collections as described at the beginning of the **SUPPLEMENTARY INFORMATION** provided in this notice.

DATES: Comments must be submitted on or before November 26, 2002.

ADDRESSES: Compliance Assessment and Media Programs Division, Office of Compliance, Office of Enforcement and Compliance Assurance, Mail Code 2223A, United States Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. A hard copy of a specific ICR may be obtained without charge by calling the identified information contact person listed in Section B under Supplementary Information.

FOR FURTHER INFORMATION CONTACT: For specific information on an individual ICR, contact the person listed in Section B under Supplementary Information.

SUPPLEMENTARY INFORMATION:

For All ICRs

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are displayed in 40 CFR part 9.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary