schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

RMR may modify the charges for Network Integration Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Network Integration Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. RMR shall charge the Transmission Customer in accordance with the revenue requirement then in effect.

Effective

The first day of the first full billing period beginning on or after April 1, 1998, through March 31, 2003.

Formula Rate

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

If a Transmission Customer requires use of subtransmission facilities, a specific facility use charge will be assessed in addition to this formula rate.

If an existing Transmission Customer elects to retain its Transmission Contract and the contract terms are payment on an energy basis, the capacity-unit rate under the formula rate will be converted to an energy-unit rate based on the individual customer's total load factor.

* * * * *

Rate

The revenue requirement in effect April 1, 1998, through September 30, 1998, is $31,555,162. This revenue requirement is based on the above formula and FY 1996 data. A recalculated revenue requirement will go into effect every October based on the above formula and updated financial and load data.

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BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Salt Lake City Area/Integrated Projects and Colorado River Storage Project—Notice of Rate Order–WAPA–78

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of rate order.

SUMMARY: Notice is given of the confirmation and approval by the Deputy Secretary of the Department of Energy (DOE) of Rate Order No. WAPA–78 and Rate Schedule SLIP–F6, 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. Also Rate Schedules SP–PTP5, SP–NW1, and SP–NFT4, placing firm and nonfirm transmission rates on the Colorado River Storage Project (CRSP) transmission system into effect on an interim basis. Lastly, Rate Schedules SP–SD1, SP–RS1, SP–EI1, SP–FR1, and SP–SSR1 placing rates for ancillary services on the CRSP system into effect on an interim basis.

The provisional firm power, firm and nonfirm transmission, and ancillary service rates will be effective from April 1, 1998 through March 31, 2003. The provisional firm power rate consists of an energy charge of 8.1 mills per kilowatthour (mills/kWh) and a capacity charge of $3.44 per kilowatt month (kW-month), which results in a composite rate of 17.57 mills/kWh. This is a 12.9 percent decrease from the current composite rate of 20.17 mills/kWh.

The provisional firm point-to-point transmission rate for 1998 is $2.23/kW-month. This is a 18.0 percent increase over the current firm transmission rate of $1.89/kW-month. The provisional network integration transmission service rate is the product of the network customer's load ratio share times one twelfth of the annual transmission revenue requirement. The non-firm point-to-point transmission rate will still be negotiated between Western and the customer, but under the new rate schedule, it shall never exceed the firm point-to-point transmission rate, which is 3.0 mills/kWh.

DATES: Rate Schedules SLIP–F6, SP–PTP5, SP–NW1, SP–NFT4, SP–SD1, SP–RS1, SP–EI1, SP–FR1, and SP–SSR1 will be placed into effect on an interim basis on the first day of the first full billing period beginning on April 1, 1998, and will be in effect until Federal Energy Regulatory Commission confirms, approves, and places the rate schedules in effect on a final basis through March 31, 2003, or until the rate schedules are superseded.

FOR FURTHER INFORMATION CONTACT: Mr. Dave Sabo, CRSP Manager, CRSP Customer Service Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, (801) 524–5493. Ms. Carol Loftin, Team Lead, Rate Analysis, CRSP Customer Service Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, (801) 524–6380.

SUPPLEMENTARY INFORMATION: By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary of Energy delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to the Administrator of 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).

Pursuant to Delegation Order No. 0204–108 and existing Department of Energy procedures for public participation in power rate adjustments at 10 CFR Part 903, and 18 CFR 300, procedures for approving Power Marketing Administration rates by FERC, Rate Order No. WAPA–78, confirming, approving, and placing the proposed SLCA/IP firm power rate adjustment, CRSP firm and nonfirm point-to-point, and network transmission rate adjustment, and ancillary services rates into effect on an interim basis, is issued, and the new Rate Schedules SLIP–F6, SP–PTP5, SP–NW1, SP–NFT4, SP–SD1, SP–RS1, SP–EI1, SP–FR1, and SP–SSR1 will be promptly submitted to FERC for confirmation and approval on a final basis.

Dated: March 23, 1998.

Elizabeth A. Moler,

Deputy Secretary.

In the matter of: Western Area Power Administration Rate Adjustments for Salt Lake City Area Integrated Projects, and Colorado River Storage Project.

[Rate Order No. WAPA–78]

Order Confirming, Approving, and Placing the Salt Lake City Area/Integrated Projects Firm Power, Colorado River Storage Project Transmission, and Ancillary Service Rates Into Effect on an Interim Basis

April 1, 1998.

These power and transmission rates are established pursuant to Section 302(a) of the Department of Energy (DOE) Organization Act, 42 U.S.C. 7152(a), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation (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 project system involved, were transferred to and vested in the Secretary of Energy (Secretary).

By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), 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. Existing DOE procedures for public participation in power rate adjustments are found at 10 CFR Part 903. Procedures for approving Power Marketing Administration rates by FERC are found at 18 CFR Part 300.

Acronyms and Definitions

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

$/kW/month: Monthly charge for capacity (i.e., $ per kilowatt (kW) per month).
AHP: Available hydro power. Maximum amount of hydro capacity and energy that will be made available to the Contractor monthly as determined by Western based on prevailing water conditions and set forth in Contractor's firm power contract.
Capacity Component: Part of the firm power rate; expressed in dollars per kW per month ($/kW-month). Applied each billing period to the maximum kW the Contractor is entitled to on a seasonal basis, as established by the Contractor's firm power contract.
CDP: Customer displacement power. One of two options available under the Replacement Purchase Options Amendment. It is the amount of supplemental power acquired or generated by the Contractor, on its own behalf, which will be used as part of the Contractor's CROD and Monthly Energy within a given period.
CME: Capitalized movable equipment.
Collbran: Collbran Project.
Contractor: An entity which has a contract with Western for SLCA/IP Firm Electric Service.
CROD: Contract rate of delivery. The maximum amount of capacity the Contractor is entitled to receive under its long-term firm power contract.
CRSP: Colorado River Storage Project (includes Seedskadee and Dolores Projects).
CRSP Act: Act of April 11, 1956, ch. 203, 70 Stat. 105, as amended, 43 U.S.C. 620–620o.
CRSP CSC: The Colorado River Storage Project Customer Service Center, Western's office in Salt Lake City, Utah.
Customer: Any entity which receives SLCA/IP power, CRSP transmission, or ancillary services.
DOE: U.S. Department of Energy.
DOE Order RA 6120.2: An order addressing power marketing administration financial reporting, used in determining revenue requirements for rate development.
DSWR: Desert Southwest Region, Western's office in Phoenix, Arizona.
EIS: Environmental impact statement.
Energy Component: Part of the firm power rate; expressed in mills per kilowatt-hour (kWh). Applied to each kWh delivered to each customer.
FERC: Federal Energy Regulatory Commission.
Firming Power: Power Western will purchase up to the AHP level. This type of purchase is included in the firm power rate.
Firming Purchases: Power purchased by Western or the Contractor above the AHP level up to the Contractor's CROD. This purchase cost is passed directly to the Contractor.
FRN: **Federal Register** notice.
FY: Fiscal year.
Glen Canyon: One of the storage units of the CRSP.
GCD EIS: Glen Canyon Dam Environmental Impact Statement.
GWh: Gigawatt-hour; equal to one million kW for a period of 1 hour.
Interior: U.S. Department of Interior.
Interest Offset: An offset to interest accrued allowed customers for the monthly payment of principal which is due on a yearly basis.
kW: Kilowatt; 1,000 watts.
kWh: Kilowatt-hour; the common unit of electric energy, equal to one kW taken for a period of 1 hour.
kW-month: Unit of electric capacity, equal to maximum amount of kW taken during 1 month.
mill: Unit of monetary value equal to .001 of a U.S. dollar; i.e., 1/10th of a cent.
mills/kWh: Mills per kilowatt-hour.
MW: Megawatt; equal to 1,000 kW or 1,000,000 watts.
NEPA: National Environmental Policy Act of 1969.
OAT: Open access transmission tariff.
OMB: Office of Management and Budget.
O&M: Operation and maintenance.
OM&R: Operation, maintenance, and replacement.
PRS: Power repayment study.
Rate Brochure: A document prepared for public distribution explaining the background and purpose of this rate adjustment proposal.
Reclamation: Bureau of Reclamation, U.S. Department of the Interior.
Replacement Purchase Options Amendment: Amendment to the SLCA/IP firm electric service contract which provides options to the Contractor for replacing Glen Canyon Dam generation lost as a result of the GCD EIS.
RMR: Rocky Mountain Region, Western's office in Loveland, Colorado.
SLCA/IP: The Salt Lake City Area/Integrated Projects, which are the CRSP, Collbran, and Rio Grande Projects.
Supporting Documentation: Work papers which support the rate proposal.
Western: Western Area Power Administration, U.S. Department of Energy.
WRP: Western replacement power. One of two options available under the Replacement Purchase Options Amendment. It is the amount of supplemental power requested by the Contractor to be acquired by Western on behalf of the Contractor as part of the Contractor's CROD and monthly energy within a given period and paid for by the Contractor on a pass-through-cost basis.

Effective Date

The new rates will become effective on an interim basis on the first day of the first full billing period beginning on or after April 1, 1998, and will remain in effect pending FERC's approval of them or substitute rates on a final basis through March 31, 2003, or until superseded.

Public Notice and Comment

The Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR Part 903, have been followed by Western in the development of these rates. The provisional firm power rate represents a change of more than 1 percent in total SLCA/IP revenues, and the provisional firm transmission rate represents a change of more than 1 percent in total CRSP transmission revenues. Therefore, they are major rate adjustments as defined at 10 CFR §§ 903.2(e) and 903.2(f)(1). The distinction between a minor and a major rate adjustment is used only to determine the public procedures for the rate adjustment.

The following summarizes the steps Western took to ensure involvement of interested parties in the rate process:

1. On March 21, 1997, letters were sent to all SLCA/IP customers and other interested parties announcing informal public meetings to be held in Utah, Colorado, New Mexico, and Arizona, from April 16 to April 25, 1997.

2. At these informal meetings, Western representatives explained the need for a rate adjustment and answered questions.

3. An FRN was published June 25, 1997 (62 FR 34255), officially announcing the proposed firm power, transmission, and ancillary services rates adjustment, initiating the public consultation and comment period, announcing the public information and public comment forums, and outlining procedures for public participation.

4. On June 27, 1997, a rate announcement package was sent to all SLCA/IP customers, CRSP firm transmission customers, and other interested parties announcing the publication of the June 25, 1997, FRN, and the beginning of the formal public process to adjust firm power, transmission, and ancillary services rates. The package contained (1) a letter announcing the upcoming public information and comment forums and (2) a copy of the June 25 FRN.

5. On July 14, 1997, a copy of the July 1997 ‘‘Brochure for Proposed Rates: Salt Lake City Area Integrated Projects Firm Power, CRSP Transmission, and Ancillary Services’ was mailed to all SLCA/IP firm power customers, CRSP transmission customers, and other interested parties.

6. At the public information forums held from August 1 to August 7, 1997, in Utah, Colorado, New Mexico, and Arizona, Western representatives provided detailed explanations of the proposed rates for SLCA/IP and CRSP, provided a list of unresolved issues that could affect the proposed rates, and answered questions. An information handout was provided at the forum.

7. The comment forums were held from September 16 to September 19, 1997, in the same locations as the information forums to give the public an opportunity to comment for the record. Eleven individuals commented at these forums.

8. Eight comment letters were received during the 90-day consultation and comment period. The consultation and comment period ended on September 23, 1997. Two additional letters were received after the 90-day consultation period. All comments have been considered in the preparation of this rate order.

Comments

Written comments were received from the following organizations:

Citizens Power, Colorado
Colorado River Energy Distributors Association, Utah
Irrigation & Electrical Districts Association of Arizona, Arizona
K.R. Saline & Associates, Arizona, on behalf of:
 Chandler Heights Citrus Irrigation District
 Electrical District No. 3 of Pinal County
 Electrical District No. 4 of Pinal County
 Electrical District No. 5 of Pinal County
 Electrical District No. 6 of Pinal County
 Electrical District No. 7 of Maricopa County
 City of Safford
 San Carlos Irrigation Project
 Maricopa Water District
 Roosevelt Irrigation District
 San Tan Irrigation District
Naslund, Salt Lake City, Utah
Platte River Power Authority, Colorado
Public Service Company of Colorado (2), Colorado
Tri-State Generation and Transmission Association, Inc., Colorado
Utah Associated Municipal Power Systems, Utah

Representatives of the following organizations made oral comments:

Arizona Power Pooling Association, Arizona
Colorado River Energy Distributors Association, Utah
Irrigation & Electrical District Association, Arizona
Electrical District No. 3 of Pinal County, Arizona
K.R. Saline & Associates, Arizona
Navajo Tribal Utility Authority, Arizona
Public Service Company of Colorado, Colorado
Platte River Power Authority, Colorado
R.W. Beck, on behalf of Colorado River Energy Distributors Association, Utah
Tri-State Generation & Transmission, Inc., Colorado
Utah Municipal Power Association, Utah

Project History

The SLCA/IP consists of the CRSP, Rio Grande, and Collbran Projects. The CRSP described herein includes two CRSP participating projects which have power facilities, 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 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. A detailed description of the Collbran, Rio Grande, and CRSP Projects is located in the Supporting Documentation.

Power Repayment Studies—Firm Power Rate

Power repayment studies are prepared each FY to determine if power revenues will be sufficient to repay, within the prescribed time periods, all costs assigned to the SLCA/IP power function. 43 U.S.C. 620(d) sets forth payment and repayment obligations of the CRSP. DOE Order RA 6120.2, section 12b, requires that:

In addition to the recovery of the above costs (operation and maintenance and interest expenses) on a year-by-year basis, the expected revenues are at least sufficient to recover (1) each dollar of power investment at Federal hydroelectric generating plants within 50 years after they become revenue producing, except as otherwise provided by law; plus, (2) each annual increment of Federal transmission investment within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; plus, (3) the cost of each replacement of a unit of property of a Federal power system within its expected service life up to a maximum of 50 years; plus, (4) each dollar of assisted irrigation investment within the period established for the irrigation water users to repay their share of construction costs; plus, (5) other costs such as payments to basin funds, participating projects or states.

A review of the PRS indicates that the existing firm power rates under Rate Schedule SLIP–F5 must be adjusted. The provisional composite rate for firm power is 17.57 mills/kWh, a 12.9 percent decrease from the existing firm power composite rate of 20.17 mills/kWh. The provisional firm power composite rate is comprised of a capacity charge of $3.44 /kW-month and an energy charge of 8.10 mills/kWh.

CRSP Transmission Service 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. SLCA/IP long-term firm power customers also incur the cost for transmission of their SLCA/IP power; and this expense is included in the firm power rate.

A review of the CRSP transmission service rate study indicates that the existing firm and nonfirm CRSP transmission service rates under Rates Schedules SP–FT4 and SP–NFT3, respectively, must be increased. The CRSP CSC is seeking approval of a rate formula for calculation of the firm point-to-point transmission rate, to be applied annually, and a formula for calculating the network integration transmission service rate to be applied annually. These formulas will be effective April 1, 1998, through March 31, 2003. The provisional rate for firm, point-to-point, CRSP transmission service is $2.23 per kW-month for 1998, an 18.0 percent increase from the existing firm transmission rate of $1.89 per kW-month, which became effective October 1, 1992. This rate will be charged to existing firm transmission customers and future firm point-to-point transmission customers.

The change in the firm CRSP transmission service rate is due to increases in the formula numerator. These increases are in transmission facilities' costs and in assigning all transmission costs to all users.

Also, the computation of the denominator changed. Western is basing the transmission system reserved for its existing long-term firm power customers on its maximum annual firm obligations instead of generating plant capacity to determine the portion of the denominator associated with the transmission of firm power.

The provisional rate for nonfirm CRSP transmission service is determined by the current market rate, not to exceed the current CRSP firm point-to-point transmission rate. The provisional rate is expressed in mills/kWh, and is a maximum of 3.0 mills/kWh for 1998.

The provisional rate for network integration transmission service is a formula calculation. The CRSP CSC has not calculated a rate because Western does not currently have any network integration transmission service customers on its CRSP transmission system.

Ancillary Services

Six ancillary services will be offered by CRSP; two are required to be purchased by the CRSP transmission customer. These two are (1) scheduling, system control, and dispatch service, and (2) reactive supply and voltage control service. The remaining four ancillary services—regulation and frequency response service, energy imbalance service, spinning reserve service, and supplemental reserve service—will also be offered but are subject to availability from SLCA/IP resources.

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 provided in conjunction with the sale of CRSP transmission services. If Western is unable to provide these services through SLCA/IP resources, the CRSP CSC will offer to provide these services by making market purchases or obtaining these services through a control area operator and passing these costs directly to the customer, including a 10 percent administrative charge.

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, and reactive supply and voltage control 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 tariffs when they assume control area operator responsibility for the CRSP, expected to be April 1, 1998.

Existing and Provisional Rates

A comparison of the existing and provisional firm power and transmission 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 4/1/98)
Firm Power Service Rate Schedule (existing rate effective 12/94)	SLIP–F5	SLIP–F6.
Firm Capacity Charge ($/kW/month)	$3.83	$3.44.
Firm Energy Charge (mills/kWh)	8.90	8.10.
Composite Rate (mills/kWh)	20.17	17.57.
Firm Point-to-Point Transmission Rate Schedule (existing rate effective 10/92)	SP–FT4	SP–PTP5.
Firm Transmission Rate ($/kW-month)	$1.89	$2.23 for 1998.
Network Transmission	N/A	SP–NW1.
Nonfirm Transmission Rate Schedule (existing rate effective 8/89)	SP–NNFT3	SP–NFT4.
Nonfirm Transmission Rate	Negotiated	Same, but not to exceed the firm rate.
Ancillary Services	N/A	SP–SD1, SP–RS1, SP–EI1, SP–FR1, SP–SSR1.

Certification of Rate

Western's Acting Administrator has certified that the SLCA/IP firm power, CRSP point-to-point, network integration and nonfirm transmission, and ancillary services rates placed into effect on an interim basis herein are the lowest possible consistent with sound business principles. The rates have been developed in accordance with agency administrative policies and applicable laws.

SLCA/IP Firm Power Rate Discussion

The provisional rate for SLCA/IP firm power is designed to recover an annual amount of revenue requirement that includes the repayment of power investment, payment of interest, purchased power expenses, OM&R expenses, and the repayment of irrigation assistance costs, as required by law.

The existing rate for SLCA/IP firm power under Rate Schedule SLIP–F5 expires November 30, 1999. Effective April 1, 1998, Rate Schedule SLIP–F5 will be superseded by the new rates in Rate Schedule SLIP–F6. The April 1, 1998, date corresponds with the implementation of the WRP and CDP options under the Replacement Purchase Options Amendment to the SLCA/IP Firm Electric Service Contracts (Amendment).

Recently, the CRSP CSC developed the Amendment which implements the Record of Decision for the Electric Power Marketing EIS to return the Contractors' allocations back to those established in the Post-89 Marketing Plan. This action increased Western's long-term firm annual contract commitment for energy from 5,699 GWh to 6,007 GWh and peak seasonal CROD from 1,290 MW to 1,406 MW. CRSP CSC's firm power commitments to meet Reclamation project use loads also increased. This increase in units sold contributes towards a lower per unit cost.

Additionally, this Amendment provides solutions which are reflective of the operational changes and reduced generating levels that resulted from the GCD EIS Record of Decision. Based on current year hydrology coupled with the reduced generating levels, Western will at times lack sufficient hydroelectric generation to meet the full CROD commitment. The Amendment provides options for either Western or the Contractor to supply the additional resources necessary to meet the full CROD commitment, at costs borne directly by the Contractor. At the Contractor's option, Western may provide the power under the WRP program through purchases on the open market, or the Contractor may provide the power under the CDP program or a combination of the two programs. Seasonal WRP and CDP provisions are effective April 1, 1998.

Each season, a portion of the resource commitments, determined by Western, will be made available to the customer through AHP. In the past, Western purchased all necessary firming power up to the CROD and included all the associated costs in the firm power rate. Under the Amendment, Western will firm up to the AHP level, if needed, and all the associated costs will be included in the firm power rate. The customer can then use WRP and/or CDP to augment the AHP to reach its full CROD.

The Amendment provisions concerning WRP and CDP programs necessitate an incremental administrative charge for those services. Western will estimate costs for these administrative charges during the first year these programs are effective—April 1, 1998, through March 31, 1999. During this first year, Western will work in consultation with customers to develop a method for tracking actual incremental WRP and CDP administrative charges. This first year will be considered a base year, and subsequent years' charges will be based upon actual costs and streamlining experiences. Contractors will be billed monthly for their share of the costs.

The provisional rates for SLCA/IP firm power consist of a capacity rate and an energy rate. The provisional capacity rate is $3.44/kW-month, and the provisional energy rate is 8.10 mills/kWh. The provisional rates for SLCA/IP firm power will result in an overall composite rate decrease of approximately 12.9 percent on April 1, 1998, when compared to the existing SLCA/IP firm power rate in Rate Schedule SLIP–F5. The total cost to the customer will depend upon the market prices for WRP and CDP. It is expected that the Contractors' total costs of receiving its full contract entitlement will be higher in the future since they will be receiving a different service under the Amendment. The firm power rate includes the cost of AHP, transmission delivery up to the Contractor's CROD at its designated point of delivery, and ancillary services.

Many factors influenced this firm power rate adjustment. The major factors having an impact upon the provisional SLCA/IP firm power rate are summarized in the table below. Because rates are calculated to return sufficient revenues based on estimated future costs, the table compares the change in the average annual projections used in the FY 1993 Rate Order PRS (which set the rate effective December 1, 1994) with the rate setting PRS prepared for this rate adjustment.

MAJOR FACTORS AFFECTING THE SALT LAKE CITY AREA INTEGRATED PROJECTS FIRM POWER RATE AVERAGE DURING RATE SETTING PERIODS

Factors	Change in average annual revenue requirement (thousands)	Estimated rate effect (mills/kWh)
Projected O&M costs decreased	$−11,359	−1.8
Purchased power expense projections and transmission costs increased	3,636	0.6
The Integrated Projects annual expenses have increased, mostly due to the inclusion of the Dolores Project	3,582	0.6
Interest expenses have decreased as a result of Western applying an Interest Offset to the CRSP PRS	−5,098	−0.8
Other annual expenses have decreased, mostly due to revised estimates for Capital Movable Equipment (CME) interest	−2,889	−0.5
Payments to project investments and additions have decreased [1]	−663	−0.1
The projected cost of replacements increased [1]	2,718	0.4
Annual average payments to irrigation assistance increased	4,505	0.7
Offsetting revenues increased	−1,827	−0.3

MAJOR FACTORS AFFECTING THE SALT LAKE CITY AREA INTEGRATED PROJECTS FIRM POWER RATE AVERAGE DURING RATE SETTING PERIODS—Continued

Factors	Change in average annual revenue requirement (thousands)	Estimated rate effect (mills/kWh)
The total amount of energy delivered increased	N/A	−1.4

[1] These changes occurred as an average over the rate setting periods, and as a result, the same impact is not exhibited in the 5 year comparison table below.

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 1998–FY 2002) TOTAL REVENUES AND EXPENSES

	Existing rate ($000)	Proposed rate ($000)	Difference ($000)
Revenue Requirements:			
Annual expenses:			
O&M	$233,974	$179,481	($54,493)
Purchased Power and Wheeling	69,075	41,265	(27,810)
Integrated Projects Requirements	28,612	39,648	11,036
Interest	210,639	161,534	(49,105)
Other	69,759	(7,053)	(76,812)
Total annual expenses	612,059	414,875	(197,184)
Annual principal payments:			
Original Project and Additions	104,069	187,592	83,524
Replacements	29,030	26,376	(2,654)
Irrigation	11,266	2,469	(8,797)
Total principal payments	144,365	216,437	72,073
Total Annual Revenue Requirements	756,424	631,312	(125,111)
(less Offsetting Annual Revenue)	136,603	85,197	(51,406)
Net Annual Revenue Requirements	619,821	546,115	(73,705)

Basis for Rate Development

The provisional power rate contains a composite rate of 17.57 mills/kWh, which is a decrease of 12.9 percent below the existing rate of 20.17 mills/kWh. It should be noted that although there appears to be a significant decrease from the existing firm power composite rate to the provisional firm power composite rate, the Contractor will not be receiving the same type of service as a result of the Amendment; therefore, the decrease is not as substantial as it appears.

Comments

The comments and responses regarding the firm power rate, paraphrased for brevity when they do not affect 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) purchased power, (2) status of issues which were identified as outstanding in the Rate Brochure, (3) O&M costs, (4) WRP/CDP administrative charges, and (5) miscellaneous comments.

1. Purchased-Power Issues

Comment: Western needs to make it very clear that, although the rates are going down, the responsibility to purchase above AHP will be transferred to the customer.

Response: As stated in the Rate Brochure page 2–2, the total cost to the customer will depend upon the market prices for WRP and CDP. However, it is expected that the Contractor's costs of receiving its full contract entitlement will be higher in the future.

Comment: Does the firm power rate include the 400 GWh of firming purchases?

Response: Yes. The Record of Decision for the Power Marketing EIS allowed Western to return to the original Post-1989 marketing CRODs and allowed for the additional purchase of 400 GWh as mentioned in the power marketing plan. The cost associated with the approximate 400 GWh of purchases are included in the firm power rate.

Comment: Customer wants clarification as to the difference between firming purchases and firming power that is referenced in the Rate Brochure. Are they purchases that Western will be making to firm up to the AHP level, or are they purchases that will be made for WRP or CDP?

Response: In general, firming power refers to the power Western will purchase up to the AHP level. This type of purchase is included in the firm power rate.

Firming purchases above the AHP level will be made by Western for those who elect WRP up to their CROD. These firming purchases will be on a pass-through-cost basis. Contractors may also elect to purchase their own power, through CDP, above what is provided by Western.

Comment: It appears that in the table that summarizes the costs, the purchased power costs increased. Yet, most of the purchased power is going to be passed through to the customers. Please explain.

Response: The annual purchased power costs shown in Table 3 of the Rate Brochure increased because of an assumption change in the PRS. In the existing rate, contractual power sales were projected to the end of the current contract period (2004), after which it was assumed that sales equaled generation, which required no additional power purchases.

In the provisional rate, contractual power sales were projected to extend through the rate setting period (60 years). This assumption change makes the average annual purchased power costs in the provisional rate higher than for the existing rate.

This modification in assumption is supported by criteria set forth in RA 6120.2 (10)(e)(2), which allows Western to forecast revenues based on past trends of customer load growth rates.

2. Status of Outstanding Issues

Comment: Customer stated Western should not include personnel retirement costs in the firm power costs.

Response: Retirement costs were not included in this provisional rate.

Comment: In the Rate Brochure on page 2–9, it says, ''If an updated depletion schedule is available during the comment period, Western may use the revised forecasts if the changes are significant in the rate setting PRS.'' One, what are the possibilities of that and, two, how will the customers know if some revised depletion schedule is available?

Response: It is CRSP CSC's policy to use the latest official data in all PRSs. An updated depletion schedule was not provided to Western and, therefore, the rate setting PRS was not modified. When an updated schedule is provided, Western will notify firm power customers in writing that the data is available for review, and this data will be included in the annual PRS prepared by Western.

Comment: On page 2–10, Western acknowledges that, ''The financial report from Reclamation or the Secretary of Interior under the Grand Canyon Protection Act has not yet been completed.'' Does Western have any knowledge of when that report will be available?

Response: Western has not received a final report signed by the Secretary of Interior and does not know when one will be provided to Western. Western included the estimate of $14 million of costs in this rate setting PRS.

3. Operation and Maintenance Costs

Comment: Western indicated that O&M costs decreased the rate by 1.5 mills/kWh. Please explain why this decrease occurred.

Response: Western has been undergoing a streamlining process throughout the agency. This streamlining reduced annual operation and maintenance costs approximately $11 million from the existing rate setting PRS.

Comment: The fifth year of projected O&M costs displays a substantial increase from previous years. This higher cost is projected throughout the remainder of the study. Western needs to analyze this to see if it is an appropriate estimate of fifth year costs.

Response: This increase in FY 2001 is due to some non-recurring O&M costs associated with a generator rewind at Crystal Powerplant, a part of the Aspinall Unit of the CRSP. This is a one-time cost and should not be carried in the study beyond that year. For this reason, the O&M cost estimates for the fifth and future years do not include the amount for the rewind. This adjustment has been made in the rate setting PRS and decreased projected O&M by approximately $2 million annually.

4. WRP/CDP Administrative Charges

Comment: Please explain how WRP customers will be charged, and if and how CDP customers will be charged. Also, the rate schedule needs to be clarified.

Response: A customer receiving WRP or other Firming Purchases on a pass-through-cost basis will pay for its proportionate share of the costs, including administrative, associated with providing this service. CDP customers, who are using the CRSP transmission system for the delivery of their CDP, will also pay for the proportionate share of the administrative costs associated with Western providing this service.

The WRP and CDP administrative charges will consist mostly of labor hours for the CRSP CSC, DSWR, and RMR employees who are working on WRP and CDP activities and will be treated as incremental labor costs. With WRP, these tasks include market studies, contract negotiation, and scheduling. With CDP, the charge will be for scheduling and determining available transfer capacity.

In the first year the WRP/CDP options are in effect (April 1, 1998), estimated charges will be applied. During that first year, actual costs will be tracked and used as a basis for subsequent years' charges.

Comment: The final paragraph of page 3–1 of the Rate Brochure seems to contradict the understanding that purchased power costs to firm allocations are carried as an expense to be recovered in the firm power rate. CDP customers should only be charged for the administrative costs.

Response: To clarify, CDP customers will not be charged firming purchases, but will be charged an administrative charge, if applicable.

The costs of firming purchases made to meet customers' allocations above AHP are not included in the firm power rate. These costs will be proportionately passed through to customers, except those receiving only CDP. The only firming power costs included in the firm power rate are those which firm up to the AHP level and which all firm power customers will pay through the firm power rate.

Comment: Customer strongly encourages Western to quickly initiate a process to determine the appropriate cost-tracking system for WRP and CDP costs as described in Section III, WRP and CDP Charges, of the Rate Brochure.

Response: A group of customers and Western employees has been organized. A meeting was held October 16, 1997, to begin this process. Once a draft of charges is completed, it will be provided to customers for comment.

Comment: Are CDP or WRP customer specific? If Western does not incur the cost as a result of the customer, then the customer does not get charged?

Response: The assumption is, if a customer is receiving CDP, that customer is purchasing its own resource. Western will deliver this resource over its system to the customer's delivery point if it has the available transmission, and this will be handled as a separate schedule by Western's schedulers. Thus, the schedulers will spend a certain amount of time each day in scheduling and accounting for this resource. In this scenario, Western will be charging a CDP administrative charge.

If the CDP is completely off Western's system, where a customer purchased power from elsewhere and Western did not have to schedule or account for it, there will be no CDP administrative charge because no additional tasks will be performed by Western.

Any customer receiving WRP will incur an administrative charge. With WRP, Western will always be performing tasks to provide this service, and, therefore, an administrative charge will always accompany WRP service.

Comment: In Section 3–2, the statements in the beginning are regarding WRP/CDP administrative costs; it ends with a paragraph regarding pass-through costs. Is Western still referring to the administrative costs associated with these pass-through-cost purchases, or are these some other costs being referred to in this paragraph?

Response: To clarify, in Section 3–1, Western is discussing two separate charges for those Contractors who are receiving WRP, or other Firming Purchases on a pass-through-cost basis, and CDP. The first charge is for the cost of WRP or Firming Purchases on a pass-through-cost basis. The second charge is for the administrative costs Western incurs as a result of providing the service. The last paragraph is referring to the firming purchase costs that will be passed-through to those Contractors who are receiving WRP, or other Firming Purchases on a pass-through-cost basis. CDP was incorrectly included in this paragraph.

5. Miscellaneous Comments

Comment: Traditionally there has been a 50/50 split between capacity and energy. Western calculated the total revenue requirements and took half of the revenue requirement for capacity and half of the revenue requirement for energy. Is that the way Western computed it this time?

Response: The CRSP CSC has stated that half of the firm power rate is allocated to capacity and half to energy based on an assumed 58.2 percent load factor. However, the actual load factor for SLCA/IP is 49.9 percent. Using the assumed load factor, rather than the actual load factor, alters the revenue split to approximately 46-percent energy and 54-percent capacity.

Comment: The Participating Projects will be collecting too much revenue starting in FY 2021.

Response: The CRSP CSC believes this comment is in reference to the Seedskadee and Dolores Participating Projects continuing to have surplus revenues included as revenue requirements. Surplus revenues from the sale of Seedskadee and Dolores Projects' power must assist in the repayment of CRSP costs as provided in Section 5 (e) of the CRSP Act of 1956.

Comment: Western used several different interest rates in calculating CME interest for the SLCA/IP. Why were the different interest rates used?

Response: Western used the coupon rate as required by Section 5(f) of the CRSP Act for all CRSP facilities. For FY 1997, this rate is 9.012 percent. For the Collbran and Rio Grande Projects, Western used the yield rate as required under RA 6120.2, Section 11. For FY 1997, this rate is 6.875 percent.

Comment: The power allocation of Caballo Dam, part of the Rio Grande Project, was increased from 40.5 percent to 100 percent. What was the reason for this change?

Response: Western incorrectly allocated 100 percent to Caballo Dam for O&M expenses. While Caballo Dam is allocated 100 percent for investments, it is only allocated 40.45 percent for O&M costs. Therefore, Western corrected the rate setting PRS to reflect an allocation of 40.45 percent for O&M. This change had no significant impact to the firm power rate.

Comment: Customer supports Western's inclusion of updated costs allocable to power for the Bonneville Unit of the Central Utah Project and urges that costs for future rate proceedings be similarly updated.

Response: Current cost estimates were included in the rate setting PRS and are reflected in the provisional rate. As revised estimates become available, they will be included in the annual CRSP power repayment study.

Comment: In the Executive Summary, the Aid to Participating Projects, which is labeled Cumulative Federal Investment, shows a large step increase of $944 million from 2002 to 2004, and then an additional step increase of $922 million from 2006 to 2007. What are the causes of these increases, and how do these increases affect the results of the power repayment study?

Response: The increase from 2002 to 2004 of $944 million results from the estimated completion of additions to the Dolores Project in Colorado and the Southern Utah County and Heber-Francis blocks of the Bonneville Unit (Central Utah Project). The increase from 2006 to 2007 reflects the addition of the Juab-Mona-Nephi block of the Central Utah Project. These are project construction costs allocated to irrigation which are beyond the ability of the irrigators in those projects to repay. These costs, along with their corresponding States' apportionment obligations, are the responsibility of power users to repay. These noninterest bearing power repayment obligations, which total about $1.9 billion, have a rate impact of approximately 4.8 mills/kWh increase.

Comment: Customer would like to compliment Western on the rate adjustment process, specifically the issue papers.

Response: The CRSP CSC believes the issue papers were beneficial for Western and its customers to increase communication. As a result, the CRSP CSC intends to continue to use issue papers for rate processes.

Comment: There is a significant increase in project use. What accounts for those increases?

Response: The projections for project use power are updated annually by Reclamation. The reason that the projections increase in successive years is due to the requirements of the Animas-La Plata Project and the Bonneville Unit of the Central Utah Project. Other projects requiring some future increase in project use power are the Navajo Indian Irrigation Project and the Paradox Valley Salinity Control Project. However, the total projections for project use power in the provisional rate are lower than those in the existing rate.

Comment: The interest offset credit shown in the ''Miscellaneous Annual Expense'' does not match the figure in the Supporting Documentation. Also, the methodology for figuring interest offset credit does not take compounding into consideration.

Response: In the Rate Brochure, the $40 million interest offset was an estimated amount because the methodology for computing the offset had not been completed. Before the rate proposal was published, the CRSP CSC had prepared several analyses using varying methodologies (including compounding and noncompounding interest) which yielded amounts greater and less than the $40 million indicated in the Rate Brochure.

Since the publication of the Rate Brochure, Western has determined the appropriate methodology for the interest offset. Western finds it appropriate to apply the interest offset methodology retroactively and to include what the interest savings would have been if the interest offset methodology would have been implemented from the beginning (1963). For this historic adjustment, Western is working toward an appropriate interest adjustment. The exact amount of the adjustment will not be available for this rate adjustment but is expected to become available during FY 1998. The estimate for this adjustment used in the provisional rate was revised downward from $40 million to $20 million based on the methodology change.

Comment: Customer supports efforts to keep water depletion assumptions realistic.

Response: The depletions were based on estimates projected using a 5-year cost evaluation period, 1998–2002, the fifth year being held constant through 2057. Western believes that this is an equitable treatment of depletions and is consistent with other projected data.

Comment: What revenues are credited to the firm power revenue requirements?

Response: Offsetting revenues, or firm power revenue credits, are any revenues that the CRSP receives which do not result from the sales of firm power, such as revenue from wheeling or transmission of nonproject power or nonfirm power sales. The major portion of the revenue credit is from wheeling revenue.

CRSP Transmission Discussion

The provisional rates for CRSP transmission service are based on a revenue requirement that recovers (i) the CRSP transmission system investment and interest costs for facilities associated with providing transmission service, and (ii) the operation, maintenance, and replacement costs allocated to transmission service. The CRSP transmission system includes facilities owned by CRSP CSC and the transmission facilities owned by others over which the CRSP CSC has contractual control. All the costs of the CRSP transmission system, including the costs paid to others for the contractual control of their transmission lines are in the total CRSP transmission revenue requirement. These revenue requirements are offset by appropriate CRSP transmission system revenues.

The firm transmission rate is based on all CRSP transmission costs. 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, and reactive supply and voltage control service are included in the appropriate provisional transmission services rates. Once Western's DSWR and RMR assume control area operator responsibility for the CRSP, expected to be April 1, 1998, 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 April 1, 1998, 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 31, 1998. The provisional rate for firm point-to-point CRSP transmission service for 1998 is $2.23 per kW-month and will result in an 18.0 percent increase from the existing rate of $1.89 per kW-month under Rate Schedule SP–FT4. The provisional rate for nonfirm CRSP transmission service is expressed in mills/kWh and will be based on market conditions, but not to exceed the firm point-to-point rate. The nonfirm transmission rate for 1998 is 3.0 mills/kWh.

Western made three significant changes in its transmission rate methodology.

1. Western is basing the transmission system reserved for its existing long-term firm power customers on its maximum annual firm obligation instead of generating plant capacity. Also, Western has reserved 130 MW for use during high hydrological conditions. The reservation of Western's transmission under certain hydrological conditions is permitted under the provisions for determination of Available Transmission Capacity which have been accepted by the regional transmission planning groups of which Western is a member. Western's interpretation of FERC Order No. 888 is that such capacity reservations for favorable hydrological conditions under these circumstances is acceptable. The sum of the maximum annual firm power obligations, which includes the 130 MW reserved for use during high hydrological conditions, is 2 MW less than the generating plant capacity amount.

2. Western annually will be recalculating the firm and nonfirm point-to-point and network integration transmission service rates to be effective April 1 based upon the proposed formulas. The rate denominator (reserved capacity) and the net annual transmisssion revenue credits will be revised each year. This rate recalculation will be done yearly by projecting for the 5 future years the revenue credits and total transmission capacity reservation and then averaging these amounts. The same average annual revenue requirement, $63.3 million, will be used for the annual recalculation of the firm, nonfirm, and network integration CRSP transmission service rates throughout the 5 years of the effective rate. Western will annually provide 30 days advance notice prior to a revised rate becoming effective.

3. Based upon review, Western now includes all transmission costs to better reflect comparability between transmission charges for firm power customers and transmission for nonpower customers. Western considers the entire transmission system, including purchase wheeling contracts, integrated, with the exception of one small transmission agreement that is purchased to serve Western's office in Montrose, Colorado. Western believes this is consistent with FERC's ruling in Order No. 888 that all transmission costs of an integrated transmission system are included. As a result, Western has allocated approximately $7.5 million of costs to transmission that had been allocated only to its firm power customers in the initial rate proposal.

The change in the CRSP firm transmission service rate is due to gross transmission revenue requirements increasing, but being offset, to some extent, by transmission revenue credits and an increase in firm wheeling reservations.

Major factors having an impact upon the provisional CRSP transmission rates are summarized in the table below. Because rates must return sufficient revenues to pay for estimated future costs, the table compares the change in the average annual projections used in the FY 1993 transmission study (which set the rate effective October 1, 1992) and the rate setting transmission study for this rate adjustment.

Major factors	Unit	Amount	Estimated rate effect ($/kW-month)
Increase in average annual revenue requirements.	$1,000	$13,125	+.51
Increase in total transmission revenue credits.	$1,000	$2,544	−.10
Increase in amount of firm transmission only service.	(1)	86,913	−.07

1 kW-year.

Network

Network integration transmission service is a new service for CRSP. Western does not currently have any network integration transmission customers on its CRSP transmission system. Western only has available transfer capacity on isolated portions of the CRSP transmission system, and therefore it does not believe it has sufficient capability to satisfy the needs of most entities desiring network integration transmission service.

The same revenue requirement that was used in determining the provisional firm point-to-point transmission rate will also be used in determining the provisional rate for the network integration transmission service. The provisional rate formula for the monthly demand charge for network integration transmission service, if purchased, 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 Western's monthly transmission system peak. Western's transmission system peak includes the sum of capacity reserved for point-to-point transmission and the SLCA/IP long-term firm power obligations. The provisional rate formula is to be effective for the period beginning April 1, 1998, through March 31, 2003.

Statement of Revenue and Related Expenses

The following table provides a summary of revenue requirements data for the CRSP firm point-to-point transmission rate through the 5-year provisional rate approval period.

CRSP COMPARISON OF 5-YEAR RATE PERIOD REVENUES AND EXPENSES (1998–2002)

	Existing rate ($000)	Provisional rate ($000)	Difference ($000)
Revenue Requirements Annual Expenses:			
Investment	$170,558	$188,550	$17,992
O&M	$80,013	$63,483	($16,530)
Replacements	$14,000	$26,716	$12,716
3rd Party Transmission Expenses	$0	$37,606	$37,606
Total Annual Expenses	$264,571	$316,355	$51,784
Less Revenue Credits			
Miscellaneous	$3,941	$1,590	($2,351)
Exchange Capacity	$8,635	$19,124	$10,489
Nonfirm Transmission	$2,130	$6,566	$4,436
Provo River Project/Ancillary	$0	$149	$149
Total Revenue Credits	$14,706	$27,429	$12,723
Total Net Annual Revenue Requirements	$249,865	$288,926	$39,061

Basis for Rate Development

The provisional firm point-to-point transmission rate for 1998 is $2.23 per kW-month, which is an 18.0 percent increase when compared to the current firm transmission rate of $1.89 per kW-month. The rate formula extends through March 31, 2003.

Comments

The comments and responses regarding the transmission rates, paraphrased for brevity when it does not affect 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) applicability of transmission rate, (2) offsetting revenues, (3) total capacity calculation, and (4) miscellaneous comments.

1. Applicability of Transmission Rate

Comment: Western indicates in its Rate Brochure that the provisional transmission rates will be applied to all ''transmission only'' sales, and therefore will not be applied to the use of the transmission system to deliver firm power obligations. Customers strongly support this position.

Response: The CRSP CSC does not, at this time, intend to bill firm power customers separately for the transmission use associated with firm power deliveries since this cost is included in the firm power rate. The CRSP CSC also does not intend, at this time, to bill firm power customers separately for ancillary services associated with firm power deliveries since this cost is also included in the firm power rate.

The transmission rate denominator reflects the use of the CRSP transmission system by all parties including the CRSP CSC. Also, the transmission costs allocated to be repaid by the long-term firm power customers are calculated on the same basis as those paid by firm point-to-point transmission customers and both customer groups are allocated an appropriate share of the transmission costs. However, they are billed differently for the service. The same costs are applied whether point-to-point or firm power customers are using the CRSP transmission system.

Comment: Customer requests clarification of what ancillary services are included in the transmission rate and why a separate scheduling and dispatch charge was developed.

Response: The provisional point-to-point and network integration transmission service rates include the CRSP CSC costs for scheduling, system control, and dispatch. These rates also include the cost of reactive supply and voltage control. Once DSWR and RMR assume control area responsibility for CRSP, expected April 1, 1998, their respective tariffs for reactive supply and voltage control will apply.

A charge for short-term sales of scheduling and dispatch service was developed and placed into effect by the Acting Administrator, pursuant to Delegation Order, and will remain in effect until DSWR and RMR assume control area operator responsibility for the CRSP, expected to be April 1, 1998. This rate was developed to be applied to those utilities that schedule through CRSP's control area because their transmission system is in CRSP's control area, but they are not using CRSP's transmission facilities. However, given the short amount of time this short-term charge would be effective, Western has decided not to implement this short-term charge.

Comment: Will the new firm point-to-point rate be applicable to all existing contracts for firm transmission?

Response: Yes. The provisional firm point-to-point transmission rates will apply to all existing and future CRSP point-to-point transmission contracts for as long as the rate is effective.

2. Offsetting revenues

Comment: In developing its transmission rate, Western did not include any revenues from ancillary services. To the extent that Western recovers more than a minor amount of revenues from ancillary services, these revenues should offset costs in developing its transmission rate. The scheduling, system control, and dispatch service rate was determined using projected schedules, but no revenues were projected in the transmission revenue credit.

Response: Western did not include revenues from ancillary services for several reasons. First, the CRSP CSC disagrees that all revenues from ancillary services should be applied to offset the transmission expenses. Rather, the only ancillary service revenues the CRSP CSC would consider applying to offset transmission expenses are from the scheduling, system control, and dispatch. Any revenues from the remaining ancillary services will be applied to offset the firm power expenses, since they are all generation related.

Secondly, the charge for short-term sales that was developed for scheduling, system control, and dispatch is only in effect until DSWR and RMR assume control area responsibility. Since the initial rate proposal, the projected control area merger date has been changed from June 1, 1998 to April 1, 1998. Therefore, the CRSP CSC does not anticipate applying a scheduling, system control, and dispatch charge, since it will no longer have its own control area April 1, 1998.

Third, the CRSP CSC projects revenue credit estimates based on the average amount of the previous 5 years. Since the CRSP CSC has not charged a separate scheduling, system control, and dispatch service during the previous 5 years, it is unable to develop a projected estimate of revenues now.

The CRSP CSC will be annually recalculating the firm point-to-point transmission rate and as part of this, revenue credits will be revised, including ancillary services. During the first 5 years, the CRSP CSC will project the scheduling, system control, and dispatch ancillary service revenues based on the average of the years of data available (e.g., 2 years of data will be summed and divided by 2). Therefore, as CRSP receives the scheduling, system control, and dispatch ancillary service revenue, they will be included and reflected in the future annual recalculations of the firm point to point transmission rate.

Comment: What are the offsetting revenues for the transmission rate?

Response: These are transmission related revenues that come into the transmission system which are not from the sale of firm transmission, such as the revenue Western receives from phase-shifting transformers and nonfirm transmission service.

Comment: The 1992–96 back-up sheet shows an average for miscellaneous revenue credit of approximately $753,000. The rate study included about $318,000.

Response: The back-up sheet was incorrect. The amount included in the transmission and firm power rate study was $318,000.

Comment: The CRSP CSC should adjust its annual formula to account for annual changes in nonfirm transmission revenue. Customer suggests that this be updated each year.

Response: Western agrees and plans to adjust its formula to account for changing revenue credits, including nonfirm transmission revenue.

Comment: Nonfirm transmission revenue credit is understated for the future. Suggest using 1996 number of $2.5 million rather than using the historical average. Using the historical average for this revenue credit assures an overrecovery of transmission revenues on a nonfirm basis.

Response: The historical data provided shows fluctuations up and down; e.g., in 1995 nonfirm wheeling revenue dropped from about $1.6 million (1994 level) to $0.8 million. For this reason, an average was used instead of the most recent year historical data. Annually, Western will be updating the 5-year rolling estimate based on previous years' revenues.

Comment: The footnote to line F of tab 20 in the Supporting Documentation states that the amount comes from the spreadsheet shown in tab 23. The data reference does not add to the numbers on tab 20.

Response: When the exchange revenue and phase shifter revenues ($2,070,467 and $1,161,000 respectively for 1998) under tab 23 are summed, they equal the amount reflected in tab 20, line F ($3,680,467 for 1998), for every year.

3. Total Capacity Calculation

Comment: Not all firm transmission reservations/requests have been included in the rate study, particularly one customer's request for 78 MW in 1999, and 27 MW between 2000–2002. The customer has received confirmation for these amounts. Furthermore, the customer has made a verbal request, for 50 MW in 1998 that has not been confirmed.

Response: The 27 MW in years 1999 through 2002 are on the Pick-Sloan transmission system, not on the CRSP transmission system and, therefore, are not included in the CRSP transmission rate study. The remaining 51 MW of the 78 MW requested in 1999 is for 4 months (June 1 through September 30). Since this is not a long-term firm arrangement, Western will include the revenues as a revenue credit once it receives the revenues.

The CRSP CSC has not confirmed the 50 MW verbal request because, as the customer was informed, the transmission availability for this particular request can not be confirmed until the first month of request is closer. If Western is able to provide transmission service to the customer, then the revenues will be accounted for as nonfirm transmission revenues once they occur, since this request is also short-term (May through December). Furthermore, this request is outside the scope of this rate adjustment process.

Comment: Customer requests a breakdown of the denominator of the firm point-to-point transmission rate. In particular, does the denominator include Salt River Project exchange agreement?

Response: The denominator includes all of Western's long-term firm obligations, which is the sum of the CROD under long-term firm power contracts, plus an amount for high hydrological conditions, plus the sum of the contracted transmission reservations. The denominator also includes the maximum amount Western might be required to provide under the agreement with Salt River Project.

Comment: The transmission rate calculation table shows 250 MW for Salt River, but the customer believes this should be 500 MW.

Response: The 500 MW is the total exchange amount. Salt River Project delivers up to 500 MW to Western at Craig, Hayden, and Four Corners collectively. In exchange, Western delivers an equal amount at Glen Canyon. The remaining Craig, Hayden, and/or Four Corners generation, which does not exchange, is wheeled for Salt River to Glen Canyon up to a maximum of 250 MW depending upon system transfer capability. The 250 MW is the maximum that Western would be required to wheel for Salt River Project if the exchange did not work. The 500 MW that are exchanged meet part of Western's CROD commitments.

Comment: The CRSP CSC is commended for proper treatment of the Salt River Project Exchange Agreement, but the proposed treatment of the Tri-State G&T Exchange Agreement is inconsistent. The 100 MW for the Tri-State Exchange is not included in the reserve capacity, as the Salt River Exchange is, and it is dealt with as an exchange credit. The treatment of revenue from the Exchange Contracts as a revenue credit to firm transmission revenue requirement results in the other firm transmission customers essentially subsidizing the costs of these contracts.

Response: The Salt River Exchange contract was entered into on the premise that it was integral to the delivery of SLCA/IP power. The revenues from the Salt River Exchange contracts are treated as a credit to the CRSP transmission revenue requirements, and the capacity amount is included in the calculation of total reserved capacity. Therefore, Salt River Project and the firm power customers jointly share in the full cost recovery of this exchange; the transmission customers do not.

However, the Tri-State contract was not entered into for the same purpose. This Tri-State agreement was in existence prior to FERC Order No. 888 and has negotiated capacity and annual payment calculation amounts that cannot be changed unilaterally.

Western is required by law to recover all the transmission costs through its revenues. In order to treat all transmission customers equitably, all the transmission customers, including the firm power customers, will share the burden of recouping the revenue requirements.

Comment: The rate study firm transmission capacity is not consistent with the supporting documentation. The rates summary refers to the firm wheeling contracted capacity in the years 2001 and 2002 as 370,315 kW; however, the Supporting Documentation shows 371,315 kW. Also, assuming the historic growth in capacity for the Page, Arizona, reservation, there needs to be an additional 1,400 kW in that year.

Response: The appropriate number of 371,315 kW is reflected in the rate order transmission study. The Page, Arizona, transmission capacity estimates are taken from projections provided by Page to Western. Western will update the capacity projections annually when establishing the yearly firm point-to-point transmission rate.

4. Miscellaneous Comments

Comment: Customer believes that the approximately $7.5 million of third-party transmission costs should not be included in the rate formula because the transmission usage of these systems will only be available for firm power customers.

Response: Almost all of the third party transmission contracts (costing approximately $7.5 million in transmission expenses) are included in the total CRSP transmission revenue requirements except one. The $2,610 annual cost paid to the Delta-Montrose Electric Associaton is to transmit power to the CRSP Operations Center in Montrose, Colorado. The Operations Center's functions deal with both transmission and electric service. Therefore, the $2,610 is allocated to both types of customers on an investment basis, the same method the O&M costs are allocated between the two customer groups. All of the other annual costs are for transmission that can be used to deliver SLCA/IP power and the power of others to points of delivery and, therefore, are included in the total CRSP transmission costs.

Western considers the entire transmission system, including purchase wheeling contracts, integrated, and believes this is consistent with FERC's ruling in Order No. 888 that all transmission costs of an integrated transmission system are included.

Additionally, Western has received inquiries for use of available transfer capacity over these contracted paths and may, in the future, provide transmission service where capacity is available.

Comment: Western has shifted transmission revenue requirements from generation to transmission-only customers by using peak annual CRODs instead of powerplant capacity. Western has moved approximately 7 percent of the transmission revenue requirement from the generation customers on the CRSP system to the transmission-only customers on the system.

Response: Western is basing its total transmission capacity reserved for its firm power obligations on the maximum CROD Western might be required to deliver under its existing firm power contracts instead of basing it on full nameplate power plant capacity. The CRSP CSC changed its calculation methodology since this is a more reasonable and accurate reflection of how much transmission system capacity must be reserved for those firm power customers.

Using full nameplate resulted in undercollection of transmission revenue requirements by transmission users, and overcollection of revenues from firm power customers. Also, Western included 130 MW for use during high hydrological conditions in its total reserved capacity calculation. In fact, the total CRSP reserved transmission capacity, less system transmission only contracts, is 2 MW less than the nameplate generating capacity; therefore, this has resulted in no impact to the transmission rate.

Comment: The proposed transmission rate structure is a good interim step towards compliance with FERC Orders No. 888 and 889. It is hoped that the CRSP transmission system will join other systems in a common approach.

Response: Western is reviewing the possible merits of joining an Independent System Operator (ISO). Should this occur, a joint ISO transmission rate will likely be developed.

Comment: The Rate Brochure states that no network service is offered at this time. Is Western using network integration transmission service when delivering firm power?

Response: Network integration transmission service is a new service being offered under Western's OAT. The firm power is transmitted under existing contracts, not under Western's OAT. FERC's Order No. 888–A, 78 FERC ¶ 61,220, mimeo at 243–244 (1997), notes the fact that Western's customers may neither be true point-to-point or network integration transmission customers.

Comment: Is Western's point-to-point service really a flexible point-to-point, that is a point could be multiple points?

Response: For existing contracts, it will depend on the contract. For future contracts, Western intends to provide the point-to-point service consistent with FERC Orders No. 888 and 888–A and under its OAT, which was published January 6, 1998, at 63 FR 521 (1998) however, the CRSP CSC is willing to customize transmission service, should that be desired and requested by new transmission customers.

Comment: What kind of loss multipliers does Western contemplate?

Response: The CRSP CSC has not made any changes to the losses in this rate adjustment. The average system loss factor is still 5.5 percent, unless otherwise stated in existing contracts.

Comment: In connection with the OAT that is being proposed, the customer understands that the FERC is requiring unbundling of the rate. The customer has been told that the proposed firm power rate is bundled and includes transmission to customers' points of delivery, up to the customers' CROD. Does the CRSP CSC contemplate another rate proceeding with their OAT to unbundle this rate?

Response: Western does not anticipate unbundling its firm power rate at this time. The functional unbundling requirement of FERC Order No. 888 does not apply to existing contracts. Furthermore, Western has established a separate charge for transmission, and the firm power customers are paying this same charge as part of their firm power rate.

Comment: Western should conduct a study of price elasticity and competition in considering future funding proposals.

Response: Western appreciates the comment; however, the CRSP CSC is unable to directly respond because it is outside the scope of this rate adjustment process.

Comment: Western should ensure that direct assignment substations costs are borne by the appropriate customers, and a breakdown of the total substation costs should be made available to the public in any transmission rate adjustment study. The customer is concerned that some of these substations, if not properly and directly assigned to the customer when they serve only a specific customer, be included in the rate.

Response: The CRSP CSC does not have any direct assignment facilities; all customers share the costs for the entire transmission system. In some instances, third parties use a part of CRSP CSC's facilities and CRSP receives revenues for this. These revenues are included as credits to the gross transmission revenue requirement.

Comment: Commentor believes that there should be no power marketing expense assigned to transmission. In general, the allocation percentage based on investment has some flaws in it in terms of certain overhead expenses.

Response: Western's power marketing staff supports both the transmission and generation functions as appropriate. CRSP's allocation methodology between power and transmission has historically been on the basis of investment, and CRSP believes that this continues to be an equitable and appropriate method.

Ancillary Services Discussion

Ancillary services are previously provided services now being offered separately by Western. Of the six ancillary services offered by the CRSP CSC, two are required to be purchased by the CRSP transmission user. These two are scheduling, system control, and dispatch service, and reactive supply and voltage control service. The remaining four ancillary services—regulation and frequency response service, energy imbalance service, spinning reserve service, and supplemental reserve service—will be offered. 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. If Western does not have the resources available from SLCA/IP, the CRSP CSC will offer to purchase the resource from the open market or from a control area operator, and pass the cost through to the customer, including a 10 percent administrative fee.

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, and reactive supply and voltage control are included in the provisional transmission services rates. Once Western's DSWR and RMR assume control area responsibility for CRSP, expected April 1, 1998, their respective reactive supply and voltage control tariffs will apply.

The provisional rates and descriptions for the six ancillary services are as follows:

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. Nonfirm customers will be supplied under the respective control area tariffs of either RMR or DSWR once control areas merge.
Reactive Supply and Voltage Control.	Reactive power support provided from generation facilities that is necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the transmission provider.	Included in appropriate transmission rates until control areas merge. After the control areas merge, RMR and DSWR tariffs will apply accordingly.
Regulation and Frequency Response.	Necessary to provide for the continuous balancing of resources, generation and interchange, with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz).	Will obtain regulation on the open market for the customer and pass through the costs, with an added 10 percent administrative charge, if unavailable from SLCA/IP resources. If available for sale, the effective SLCA/IP firm power capacity rate, will be charged.
Energy Imbalance	Provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a control area over a single hour.	Will obtain from control area operator and pass through the costs, with an added 10 percent administrative charge.
Spinning Reserve	Needed to serve load immediately in the event of a system contingency.	Will obtain on the open market for the customer and pass through the costs, with an added 10 percent administrative charge, if unavailable from SLCA/IP resources. If available for sale, the effective SLCA/IP firm power rate, will be charged.
Supplemental Reserve	Needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.	Will obtain on the open market for the customer and pass through the costs, with an added 10 percent administrative charge, if unavailable from SLCA/IP resources. If available for sale, the effective SLCA/IP firm power rate, will be charged.

Comments

The comments and responses regarding ancillary service rates, paraphrased for brevity when they do not affect 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) scheduling, system control, and dispatch charge, (2) energy imbalance charge and deadband, and (3) miscellaneous comments.

1. Scheduling, System Control, and Dispatch Charge

Comment: Clarification of scheduling, system control, and dispatch charges is necessary. What charges will be assessed beyond the first five schedule changes per day? Can transactions entering or leaving the control area now be under one schedule? Will there be a separate category for schedules which require hourly schedule changes?

Response: The CRSP CSC developed a short-term scheduling, system control, and dispatch charge for those entities which have transmission in the Western Area Upper Colorado control area. However, because this control area is expected to be merged with two other control areas by April 1, 1998, CRSP does not anticipate applying this short-term charge.

Once DSWR and RMR assume control area operator responsibility, then transactions entering or leaving different control areas will be assessed charges appropriately by each control area.

Comment: There is an inherent conflict that exists between the limitation of five schedule changes per day and the burden to follow a load which is imposed under the Energy Imbalance Service provisions. To avoid being charged for energy imbalance, one must make a large number of schedule changes.

Response: The CRSP CSC developed a short-term scheduling, system control, and dispatch rate which established a limitation of 5 schedule changes per day. This rate, however, will not be applied because of the timing of the control area merger. Once DSWR and RMR assume control area responsibility for CRSP, the scheduling, system control, and dispatch rate and scheduling limitation set forth in their applicable tariffs will apply.

2. Energy Imbalance Charge

The CRSP CSC received several comments regarding its proposed energy imbalance service charge. Since the rate proposal, Western has revised the projected date from June 1, 1998, to April 1, 1998, for RMR and DSWR to assume control area operator responsibility. As a result of this revised control area merger date, the CRSP CSC will not be placing a separate energy imbalance charge into effect, rather it will offer to obtain this service from a control area operator, and pass the costs through directly to the customer, with an added 10 percent administrative charge. Therefore, the CRSP CSC is not responding to any of the comments received regarding this charge.

3. Miscellaneous

Comment: Does Western expect the price for supplemental reserves to be less than spinning reserves?

Response: The CRSP CSC developed the charges assuming the same charge would apply to both services. The CRSP CSC does not anticipate having reserves available from SLCA/IP resources. If these are available, they will be priced at the firm power rate. If they are unavailable, the CRSP CSC will purchase and pass these costs through to the customer, including a 10 percent administrative charge for the cost of providing the service.

Comment: The customer strongly supports Western continuing to provide ancillary services as part of firm power services.

Response: As part of its long-term power obligations, Western will continue to provide ancillary and transmission services and include the costs in the firm power rate.

Comment: The customer wants tracking and allocation methodologies for expenses and revenues associated with ancillary services to be analyzed in detail for proper tracking and accounting for each Federal Project customer in the future. Need to identify what resources are available to provide ancillary services to those customers which are not firm power customers.

Response: The CRSP CSC plans to begin a process of determining the amount of services each customer receives and also to determine the amount of ancillary services committed. However, the CRSP CSC does not anticipate having any SLCA/IP resources available for ancillary services to offer since these resources have already been committed to the SLCA/IP firm power customers.

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980, 5 U.S.C. 601–612, requires Federal agencies to perform a regulatory flexibility analysis if a proposed rule is likely to have a significant economic impact on a substantial number of small entities. Western has determined that this action relates to rates or services offered by Western and, therefore, is not a rule within the purview of the Act.

Environmental Evaluation

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

Executive Order 12866

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

Submission to Federal Energy Regulatory Commission

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

Order

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I confirm and approve on an interim basis, effective April 1, 1998, Rate Schedules SLIP–F6, SP–PTP5, SP–NW1, SP–NFT4, SP–SD1, SP–RS1, SP–EI1, SP–FR1, and SP–SSR1. The rate schedules shall remain in effect on an interim basis, pending FERC confirmation and approval of them or substitute rates on a final basis through March 31, 2003.

Dated: March 23, 1998.

Elizabeth A. Moler,

Deputy Secretary.

Rate Schedule SLIP–F6, (Supersedes Schedule SLIP–F5); Salt Lake City Area Integrated Projects; Arizona, Colorado, Nevada, New Mexico, Utah, Wyoming

Schedule of Rates for Firm Power Service

Effective

First day of the first full billing period beginning on or after April 1, 1998, and extending through March 31, 2003, 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

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

Monthly Rate

Demand Charge: $3.44 per kilowatt of billing demand.

Energy Charge: 8.10 mills per kilowatthour of use.

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 Purchased Resources

Purpose of Adjustment: The Record of Decision on Western's Electric Power Marketing Environmental Impact Statement returned the Contractor's allocations to those established in the Post-1989 Marketing Plan (Plan). This Plan originally included a 400 GWh pass-through-cost purchase. However, this 400 GWh is now included in the rate as a purchased power expense, but it may not be sufficient to meet the Contractor's full contract entitlement. Therefore, additional firming purchases may be needed in order to meet the Contractor's full entitlement. Western developed a Replacement Purchase Options Amendment, effective on April 1, 1997, which provided options for either Western to replace the firming purchases on a pass-through-cost basis through Western Replacement Power (WRP) or for the Contractor to replace the firming purchases on its own through Customer Displacement Power (CDP). Those Contractors who are not receiving service under the Replacement Purchase Options Amendment will also receive additional firming on a pass-through-cost basis. This adjustment is to ensure that Western recovers the purchased power costs and any other associated costs for the firming purchases.

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 within a given period and be paid for on a pass-through-cost basis. Western will include in the Contractor's monthly power bill 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.

Adjustment for Contractors not currently receiving service under the Replacement Purchase Options Amendment.

When Western purchases firming resources on behalf of the Contractor, the Contractor shall be billed for its proportionate share of the costs associated with the additional firming purchase.

Rate Schedule SP–PTP5, (Supersedes Schedule SP–FT4); Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, 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 April 1, 1998, and extending through March 31, 2003, 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 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 the net annual transmission revenue requirement averaged over a 5-year cost evaluation period (1998–2002). The total gross annual transmission revenue requirement, $63,271,015, is reduced by the currently projected 5-year average revenue credits to determine the total net annual costs to be recovered. The total net annual transmission revenue requirement to be recovered is divided by the currently projected 5-year average capacity reservation needed to meet firm power and transmission commitments in kW, plus the total network integration loads at system peak, to derive a cost/kW-month. The formula is as follows:

$63,271,015 − Total Revenue Credits=Total Net Annual Transmission Revenue Requirement÷Total Firm Capacity reservations+Network loads at system peak= Unit Cost/Year ($/kW-year)÷12

This formula will be recalculated by revising the rate denominator (reserved capacity) based on current reservations and the net annual transmission credits, and a revised rate, if needed, will be placed into effect every April 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–RS1 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 utilized 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.

Rate Schedule SP–NW1; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rate for Network Integration Transmission Service

Effective

The first day of the first full billing period beginning on or after April 1, 1998, and extending through March 31, 2003, 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 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.

Network Rate Formula

The network integration transmission service rate 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. The formula is as follows:

$63,271,015 − Total Revenue Credits=Total Net Annual Transmission Revenue Requirement÷Total Firm Capacity reservations + Network loads at system peak=Unit Cost/Year ($/kW-year)÷12

The rate for network transmission service includes scheduling, system control, and dispatch. Rate Schedule SP–RS1 will be attached as part of this Rate Schedule and apply to network transmission customers.

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.

Rate Schedule SP-NFT4; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rate for Nonfirm Point-to-Point Transmission Service

Effective

The first day of the first full billing period beginning on or after April 1, 1998, and extending through March 31, 2003, or until superseded by another rate schedule, whichever occurs earlier.

Available

This schedule supersedes SP-NFT3 and is available for the Nonfirm Transmission Service on the Colorado River Storage Project transmission system.

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 Open Access Tariff.

Rate

The Proposed Rate for nonfirm point-to-point CRSP transmission service is a mills/kWh rate based on market conditions but never higher than the firm point-to-point rate as specified in Rate Schedule SP-FT5 or any superseding rate schedule.

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 a service contract is not available, the losses shall be specified in advance and may be included in the rates for the service.

Rate Schedule SP-SD1; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rates for Scheduling, System Control, and Dispatch Ancillary Service

Effective

Beginning on April 1, 1998, and extending through March 31, 2003.

Available

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

Applicable

To all customers who are not using the CRSP transmission but are receiving scheduling, system control, and dispatch 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. Once control areas consolidate, Rocky Mountain and Desert Southwest Regions' tariffs will apply to nonfirm customers accordingly.

Rate Schedule SP-RS1; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rates for Reactive Supply and Voltage Control Ancillary Service

Effective

Beginning on April 1, 1998, and extending through March 31, 2003.

Available

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

Applicable

To all CRSP transmission customers.

Character of Service

Is reactive power support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.

Rate

Service is included in appropriate transmission rates. Once control areas merge, Rocky Mountain and Desert Southwest Regions' tariffs will apply accordingly.

Rate Schedule SP-EI1; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rates for Energy Imbalance Ancillary Service

Effective

Beginning on April 1, 1998, and extending through March 31, 2003.

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 scheduled and the actual delivery of energy to a load located within a control area over a single hour.

Rate

Will obtain from control area operator and pass through the costs, with an added 10 percent adminstrative charge.

Rate Schedule SP–FR1; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rates for Regulation and Frequency Response Ancillary Service

Effective

Beginning on April 1, 1998, and extending through March 31, 2003.

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

Is necessary to provide for the continuous balancing of resources, generation and interchange, with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz).

Rate

Will obtain regulation on the open market for the customer and pass through the costs, with an added 10 percent administrative charge, if unavailable from SLCA/IP resources. If available for sale, the SLCA/IP firm power capacity rate, currently in effect, will be charged.

Rate Schedule SP–SSR1; Colorado River Storage Project; Arizona, Colorado, New Mexico, Wyoming, Utah

Schedule of Rates for Spinning and Supplemental Reserve Ancillary Service

Effective

Beginning on April 1, 1998, and extending through March 31, 2003.

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 6 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

Spinning Reserve will obtain on the open market for the customer and pass through the costs, with an added 10 percent administrative charge, if unavailable from SLCA/IP resources. If available for sale, the SLCA/IP firm power rate currently in effect will be charged.

Supplemental Reserve will obtain on the open market for the customer and pass through the costs, with an added 10 percent administrative charge, if unavailable from SLCA/IP resources. If available for sale, the SLCA/IP firm power rate currently in effect will be charged.

[FR Doc. 98–8939 Filed 4–3–98; 8:45 am]
BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–5991–5]

Contractor Access to Confidential Business Information Under the Clean Air Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The United States Environmental Protection Agency has authorized the following subcontractor to access information that has been, or will be, submitted to the EPA under section 114 of the Clean Air Act (CAA) as amended: Sanford Consulting, 105 Fallenwood Avenue, Durham, North Carolina, 27713. Some of this information may be claimed to be confidential business information (CBI) by the submitter. This subcontractor will be providing support to the EPA under contracts 68–D6–0008 and 68–D6–0010. The prime contractor on this contract is EC/R, Incorporated, 2327 Englert Drive, Suite 100, Durham, North Carolina, 27713.

DATES: Access to confidential data submitted to EPA will occur no sooner than April 6, 1998.

FOR FURTHER INFORMATION CONTACT:

Melva Toomer, Document Control Officer, Office of Air Quality Planning and Standards (MD–11), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, (919) 541–0880.

SUPPLEMENTARY INFORMATION: The EPA is issuing this notice to inform all submitters of information under section 114 of the CAA that the EPA may provide the above mentioned subcontractor access to these materials on a need-to-know basis. Under the direction of the prime contractor, this subcontractor will provide technical support to the Office of Air Quality Planning and Standards (OAQPS) in developing Federal Air Pollution Control Regulations.

In accordance with 40 CFR 2.301(h), the EPA had determined that the above subcontractor requires access to CBI submitted to the EPA under sections 112 and 114 of the CAA in order to perform work satisfactorily under the above noted contract. The subcontractor's personnel will be given access to information submitted under section 114 of the CAA. The subcontractor's personnel will be required to sign nondisclosure agreements and will receive training on appropriate security procedures before they are permitted access to CBI.

Clearnace for access to CAA CBI is scheduled to expire on September 30, 2001 under contract 68–D6–0008 and contract 68–D6–0010.

Dated: March 31, 1998.

Richard Wilson,

Acting Assistant Administrator for Air and Radiation.

[FR Doc. 98–8963 Filed 4–3–98; 8:45 am]
BILLING CODE 6560–50–M