DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Hydropower Licensing Public Outreach Meeting; Portland, ME

March 31, 1998.

The Office of Hydropower Licensing will hold a public Outreach Meeting in Portland, Maine on Thursday, April 23, 1998. The Outreach Meeting is scheduled to start at 9:00 am and finish at 5:00 pm.

The purpose of the Outreach program is to familiarize federal, state, and other government agencies, Indian tribes, nongovernmental organizations, licensees, and other interested parties with the Commission's hydropower licensing program. The topics for the Outreach Meeting are pre-licensing program. The topics for the Outreach Meeting are pre-licensing, licensing, and post-licensing procedures for hydroelectric projects in Maine, New Hampshire, Connecticut, and Massachusetts whose licenses expire between calendar years 2000 and 2010.

Staff from the Commission's Office of Hydropower Licensing will preside over the meeting.

The location of the Outreach Meeting is: The Marriott, 200 Sable Oaks Drive, South Portland, ME 04106, (207)871–8000, (207)871–7971 *fax.

If you plan to attend, notify Ron McKitrick, Eastern Outreach Coordinator, fax: 202–219–2152; telephone: 202–219–2783 or Theresa Gibson, (202) 219–2793.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–8881 Filed 4–3–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Western Area Power Administration

Loveland Area Projects—Rate Order No. WAPA–80

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–80 and Rate Schedules L–NT1, L–FPT1, N–FPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, and L–AS6, placing formula rates into effect on an interim basis for firm and non-firm transmission on the Western Area Power Administration Loveland Area Projects (LAP) transmission system and for ancillary services for the Western Area Colorado Missouri control area (WACM). These schedules supersede Rate Schedules LT–3 and LT–4.

The charges for network and point-to-point transmission service and energy imbalance service will be implemented in three steps, between April 1, 1998, and October 1, 1999. The charges for the other five ancillary services will be implemented in the first step. Each step and subsequent annual recalculation will be based on updated financial data and loads. Network transmission service charges will be based on the Transmission Customer's load-ratio share of the annual revenue requirement for transmission. Point-to-point transmission service will be based on monthly reserved capacity on the transmission system. The charges for ancillary services will be based on the costs of the WACM.

FOR FURTHER INFORMATION CONTACT: Mr. Daniel T. Payton, Rates Manager, Rocky Mountain Customer Service Region, Western Area Power Administration, P.O. Box 3700, Loveland, CO 80539–3003, (970) 490–7442, or e-mail (dpayton@wapa.gov).

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 non-exclusive 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).

Rate Order No. WAPA–80, confirming, approving, and placing the LAP network, firm point-to-point, and non-firm point-to-point transmission, and the new ancillary services formula rates into effect on an interim basis, is issued. Rate Order No. WAPA–80 was prepared pursuant to Delegation Order No. 0204–108, existing DOE procedures for public participation in power rate adjustments in 10 CFR Part 903, and procedures for approving Power Marketing Administration rates by FERC in 18 CFR 300. The new Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, and L–AS6 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 Adjustment for Loveland Area Projects Transmission and Ancillary Services

April 1, 1998.

Order Confirming, Approving, and Placing the Loveland Area Projects Transmission and Ancillary Service Formula Rates Into Effect on an Interim Basis

These transmission and ancillary service formula rates are established pursuant to Section 302 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) 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 non-exclusive basis to the Administrator of the Western Area Power Administration (Western); (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Federal Energy Regulatory Commission (FERC).

Existing DOE procedures for public participation in power rate adjustments are found in 10 CFR Part 903. Procedures for approving Power Marketing Administration rates by FERC are found in 18 CFR Part 300.

Acronyms/Terms and Definitions

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

Acronym/Term Definition

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

12 cp: Rolling 12-month coincident peak average.

A&GE: Administrative and general expense.

C&RE: Conservation and Renewable Energy.

CME: Capitalized movable equipment.

CRSP: Colorado River Storage Project.

Customer Brochure: ''Loveland Area Projects Customer Brochure: Proposed Rates for Transmission and Ancillary Services'' prepared in September 1997 by the Rocky Mountain Customer

Service Region for public distribution explaining the background and purpose of this rate adjustment proposal.

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.

Federal Customers: Loveland Area Projects (LAP) customers taking delivery of long-term firm service under Firm Electric Service Contracts, and Project Use Power Customers.

FERC: Federal Energy Regulatory Commission.

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

Firm Electric Service Contract: Contracts for the sale of long-term firm LAP Federal energy and capacity, pursuant to the Post-1989 General Power Marketing and Allocation Criteria (Marketing Plan).

FY: Fiscal Year.

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 the maximum of kW taken during 1 month.

LAP: Loveland Area Projects.

LAP Transmission System Total Load: Average 12-cp monthly system peak for network transmission service, average 12-cp monthly entitlements of Federal Customers, and reserved capacity for all firm point-to-point transmission service.

Load ratio share: Network Transmission Customer's hourly load (including its designated network load not physically interconnected with Western) coincident with Western's monthly transmission system peak.

Long-term firm point-to-point transmission service: Annual firm point-to-point transmission service reservation with 12 consecutive equal monthly amounts.

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.

Monthly entitlements: Maximum capacity to be delivered each month under Firm Electric Service Contracts. Each monthly entitlement is a percentage of the seasonal contract-rate-of-delivery, based on 90-percent hydrologic probability established in the Marketing Plan.

MW: Megawatt; equal to 1,000 kW or 1,000,000 watts.

NEPA: National Environmental Policy Act of 1969.

NPPD: Nebraska Public Power District.

O&M: Operation and maintenance.

P–SMBP: Pick-Sloan Missouri Basin Program.

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

PMOC: Power Marketing and Operations Complex.

Post-1989 General Power Marketing and Allocation Criteria: Criteria for the sale of energy with capacity from the P–SMBP–WD and the Fryingpan-Arkansas Project by Criteria: the RMR.

Provisional Rate Schedule: Rate schedule approved on an interim basis by the Deputy Secretary of the DOE.

Reclamation: Bureau of Reclamation, U.S. Department of the Interior.

RMR: The Rocky Mountain Customer Service Region; Western's office in Loveland, Colorado.

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

SEPA: Southeastern Power Administration.

Short-term firm point-to-point transmission service: Firm point-to-point transmission service with service of less duration than 12 consecutive monthly service amounts.

Supporting documentation: Work papers which support the rate proposal.

Tariff: Western Area Power Administration, Open Access Transmission Service Tariff, Docket No. NJ–98–1–000.

Transmission Customer: The RMR customer taking network or point-to-point transmission service.

WACM: Western Area Colorado Missouri control area.

Western: Western Area Power Administration, U.S. Department of Energy.

Effective Date

The provisional formula 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 be in effect pending FERC's approval of them or substitute formula rates on a final basis through March 31, 2003, or until superseded. These formula rates will be applied under existing transmission contracts and Western's Open Access Transmission Service Tariff (Tariff) and conform with the spirit and intent of the FERC Order No. 888. The Rocky Mountain Customer Service Region (RMR) will replace Schedules 1 through 8 and Attachment H of Western's Tariff with these rate schedules for service on the Loveland Area Projects (LAP) system.

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 formula rates and schedules. The provisional firm transmission rate represents an increase of more than 1 percent in total LAP transmission revenues; therefore, it is a major rate adjustment 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. During the spring of 1997, RMR representatives met informally with individual LAP customers to explain the need for a rate adjustment.

2. RMR published a **Federal Register** notice on September 19, 1997 (62 FR 49218), officially announcing the proposed 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.

3. On September 25, 1997, RMR mailed a copy of the ''Loveland Area Projects Customer Brochure: Proposed Rates for Transmission and Ancillary Services'' to all LAP Transmission Customers and other interested parties.

4. RMR held a public information forum on October 23, 1997, in Denver, Colorado. Western representatives explained the need for the rate adjustment in greater detail and answered questions.

5. RMR held a comment forum on November 18, 1997, in Denver, Colorado, to provide the public an opportunity to comment for the record. Four individuals commented at this forum.

6. Seven commentors submitted letters during the 90-day consultation and comment period. The consultation and comment period ended on December 18, 1997. All comments have been considered in the preparation of this Rate Order.

Comments

Representatives of the following organizations made oral comments:

Platte River Power Authority, Colorado, on behalf of Loveland Area Customer Association

Colorado Springs Utilities (CSU), Colorado

Kansas Electric Power Cooperative, Inc., Kansas
New Century Energies, Texas, on behalf of Public Service Company of Colorado, Colorado, and Cheyenne Light, Fuel and Power Company, Wyoming

The following organizations submitted written comments:

Arkansas River Power Authority, Colorado
Colorado Springs Utilities, Colorado
Loveland Area Customer Association, Colorado
Nebraska Public Power District (NPPD), Nebraska
Platte River Power Authority, Colorado
New Century Energies, Texas
Tri-State Generation and Transmission Association, Inc. (Tri-State), Colorado

Project Description

RMR offers transmission service on LAP transmission facilities, which include transmission lines, substations, communication equipment, and related facilities. LAP is comprised of two power projects: the Pick-Sloan Missouri Basin Program-Western Division (P–SMBP–WD) and the Fryingpan-Arkansas Project (Fryingpan-Arkansas). The two projects were integrated for operational and marketing purposes in 1989. LAP serves Federal and Transmission Customers in a four-state area, over a transmission system of approximately 3,485 miles (5,607 circuit kilometers) and 80 substations.

Western will offer ancillary services from the Western Area Colorado Missouri control area (WACM) resources, which represent a combination of some Colorado River Storage Project (CRSP) generation resources and all of the LAP generation resources.

P–SMBP–WD

The initial stages of the Missouri River Basin Project were authorized by Section 9 of the Flood Control Act of 1944 (58 Stat. 887, 891, Pub. L. 534, 78th Congress, 2nd session). It was later renamed the Pick-Sloan Missouri Basin Program (P–SMBP). The P–SMBP encompasses a comprehensive program, with the following authorized functions: flood control, navigation improvement, irrigation, municipal and industrial water development, and hydroelectric production for the entire Missouri River Basin. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota, and Wyoming.

The Colorado-Big Thompson, Kendrick, Riverton, and Shoshone Projects were administratively combined with P–SMBP in 1954, followed by the North Platte Project in 1959. These projects are known as the ''Integrated Projects'' of the P–SMBP. The Riverton Project was reauthorized as a unit of the P–SMBP in 1970.

The P–SMBP–WD and the Integrated Projects include 19 powerplants. There are six powerplants in the P–SMBP–WD: Glendo, Kortes, and Fremont Canyon Powerplants on the North Platte River; Boysen and Pilot Butte on the Wind River; and Yellowtail Powerplant on the Big Horn River.

In the Colorado-Big Thompson there are also six powerplants. The Green Mountain Powerplant on the Blue River is on the West Slope of the Rocky Mountains. The five remaining powerplants are on the East Slope of the Continental Divide: Marys Lake, Estes, Pole Hill, Flatiron, and Big Thompson.

The Kendrick Project has two power production facilities: Alcova and Seminoe Powerplants. Power production facilities in the Shoshone Project are Shoshone, Buffalo Bill, Heart Mountain, and Spirit Mountain Powerplants. The only production facility in the North Platte Project is the Guernsey Powerplant.

Fryingpan-Arkansas Project

The Fryingpan-Arkansas is a transmountain diversion project in central and southeastern Colorado, which was authorized by the Act of August 16, 1962 (Pub. L. 87–590, 76 Stat. 389, as amended by Title XI of the Act of October 27, 1974, Pub. L. 93–493, 88 Stat. 1487, 1497). The Fryingpan-Arkansas diverts water from the Fryingpan River and other tributaries of the Roaring Fork River to the Arkansas River on the East Slope of the Continental Divide. The Fryingpan and Roaring Fork Rivers are part of the Colorado River Basin on the West Slope of the Rocky Mountains. The water diverted from the West Slope, together with regulated Arkansas River water, provides supplemental irrigation, municipal and industrial water supplies, and hydroelectric power production. Flood control, fish and wildlife enhancement, and recreation are other important purposes of the Fryingpan-Arkansas. The only generating facility in the Fryingpan-Arkansas Project is the Mt. Elbert Pumped-Storage Powerplant on the East Slope of the Rocky Mountains.

Colorado-River Storage Project

The CRSP was authorized by the Colorado River Storage Project Act, ch. 203, 70 Stat. 105, on April 11, 1956. The CRSP provides for the comprehensive development of the Upper Colorado River Basin (Upper Basin). It furnishes the long-term regulatory storage needed to allow states in the Upper Basin (Colorado, New Mexico, Utah, and Wyoming) to meet their water delivery obligations to the states of the Lower Basin (Arizona, California, and Nevada) and still use the water apportioned to them by the Colorado River Compact of 1922. The part of the CRSP in WACM is the territory north of Shiprock, New Mexico. The CRSP hydroelectric facilities providing ancillary services for WACM are Aspinall (formerly Curecanti) and part of Glen Canyon. As of April 1, 1998, the southern portion of the CRSP will be operated by Western's Desert Southwest Customer Service Region in Phoenix, Arizona.

LAP Transmission Service

RMR prepared a transmission service rate study based on cost of service for the LAP transmission system. RMR is seeking approval of formula rates for calculation of point-to-point transmission rates and the network transmission service revenue requirement. These formulas will be applied annually. Transmission service for delivery of LAP long-term firm Federal power to Federal Customers will continue to be bundled in their firm power rate under existing contracts which expire in 2024. The transmission rates include the cost of Scheduling, System Control, and Dispatch Service.

The existing LAP transmission rate of $1.88/kW-month, placed into effect under Rate Schedule L–T3 in 1994, is no longer sufficient to recover annual costs (including interest expense) and capital requirements. Although the cost basis for the transmission rates has changed since 1994, the primary reason for a rate adjustment is the reassessment of the load data. A detailed review of load and meter data has determined that the loads used in the 1994 analysis (1,957,882 kW) were significantly in excess of actual system use (1,126,263 kW) and were not billable under the terms of LAP contracts.

About 500 MW of the difference is over-projections of actual usage of the transmission service. Approximately 200 MW is due to the use of a non-coincident annual peak in the 1994 rate analysis, as opposed to the use of the FERC-endorsed 12-consecutive peak (12-cp) method in the provisional rates. About 100 MW for an existing contract that is billed at a discounted rate was excluded from the present rate denominator and included as a revenue credit. In combination, these factors result in approximately 800 MW of reduced load on the LAP transmission system, with a corresponding increase in transmission rates.

RMR will offer existing Transmission Customers the opportunity to convert their existing contracts to service agreements under Western's Tariff. The customer will designate network or point-to-point transmission service and applicable ancillary services. The earliest that an existing transmission contract can be converted under the Tariff and the Provisional Rate Schedules is April 1, 1998.

For the formula rates, RMR assumed that all existing contracts that are based on capacity or energy transmitted will take network transmission service, and that customers which currently reserve capacity for transmission service will take point-to-point transmission service. If an existing Transmission Customer elects to retain its transmission contract, transmission service will continue under the terms of the existing contract, but under the Provisional Rate Schedules (L–NT1, L–FPT1, and L–NFPT1 for transmission, and L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, and L–AS6 for ancillary services). These Provisional Rate Schedules will supersede the rate schedules in the existing contracts. If an existing Transmission Customer is billed on an energy (rather than capacity) basis, the Provisional Rate Schedules stipulate that the rate per capacity unit will be converted to a rate per energy unit, based on the individual Transmission Customer's load factor.

RMR recognizes the impact that the increase in cost for transmission service from $1.88/kW-month to $3.19/kW-month may have on its customers. RMR is proposing a three-step implementation plan for the transmission rate adjustment in an attempt to mitigate these impacts. The implementation dates and basis for the calculation for each of the three steps are described below. The starting point for the calculation is an estimate of the third-step rate, based on Fiscal Year (FY) 1996 financial data and 1995 load data. In subsequent steps, the third-step rate will be recalculated based on the formula rate and updated financial and load data.

Step 1—April 1, 1998

The first-step point-to-point rate is the existing rate ($1.88/kW-month) plus one-third of the difference between the existing rate and the estimated third-step rate. The network transmission service revenue requirement is the first-step point-to-point rate multiplied by the LAP Transmission System Total Load.

Step 2—October 1, 1998

The second-step point-to-point rate will be the existing rate ($1.88/kW-month) plus two-thirds of the difference between the existing rate and the recalculated third-step rate. The third-step rate will be recalculated, following the formula rate, using FY 1997 financial and load data.

Step 3—October 1, 1999

The third-step point-to-point transmission service rate and network transmission service revenue requirement will be recalculated, following the formula rates and FY 1998 financial and load data.

The rates will subsequently be recalculated every year, effective October 1, based on the approved formula rates and updated financial and load data. RMR will provide customer notice of changes in rates no later than July 1 of each year.

Ancillary Services

RMR will offer the six ancillary services defined by FERC to all customers. The six ancillary services are: (1) Scheduling, System Control, and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service (VAR Support); (3) Regulation and Frequency Response Service (Regulation); (4) Energy Imbalance Service; (5) Spinning Reserves; and (6) Supplemental Reserves. The ancillary services formula rates are designed to recover only the costs incurred for providing the service(s). The rates for ancillary services are based on WACM control area costs, per FERC.

RMR will implement the Energy Imbalance Service bandwidths simultaneously with the transmission service rates to allow for a transition period, whereby, customers may improve their equipment and revise their scheduling practices. The implementation schedule will be:

April 1, 1998—6 percent bandwidth

October 1, 1998—5 percent bandwidth

October 1, 1999—3 percent bandwidth

Comparison of Existing and Provisional Rates for Transmission and Ancillary Services

The following is a comparison of existing rates, step-one rates, and an estimate of the step-three rates under the provisional formula rates and using FY 1996 data. Rates for step-two and three will be recalculated based on updated financial and load data prior to implementation. Subsequently, these rates will be updated annually based on approved formula rates.

COMPARISON OF EXISTING, STEP-ONE, AND ESTIMATED STEP-THREE RATES

Class of service	Existing rate schedule and rate	Rate schedule and step-one rates April 1, 1998	Rate schedule and estimated step-three rates [1]
Firm Transmission	LT–3	L–NT1 or L–FPT1, and L–AS1 thr. 6.	L-NT1 or L–FPT1, and L–AS1 thr. 6.
	$1.88/kW-mo	See applicable classes below. [2]	See applicable classes below.[2]
Network Transmission	N/A	L–NT1	L–NT1
		Load ratio share of 1/12 of the revenue requirement of $31,555.162 [3].	Load ratio share of 1/12 of the revenue requirement of $43,153,308 [3]
Firm Point-to-Point Transmission	N/A	L–FPT1	L–FPT1
		$2.32/kW-mo [3]	$3.19/kW-mo [3]
Non-firm Point-to-Point Transmission.	LT–4	L–NFPT1	L–NFPT1
	2.6 mills/kWh	Maximum of 3.33 mills/kWh	To be calculated October 1, 1999.
Scheduling, System Control, and Dispatch.	N/A	L–AS1	L–AS1
		$25.71 per schedule per day for non-transmission customers.	To be calculated October 1, 1999.
Reactive Supply and Voltage Control from Generation Sources.	N/A	L–AS2	L–AS2
		$0.112/kW–mo	To be calculated October 1, 1999.
Regulation and Frequency Response.	N/A	L–AS3	L–AS3
		$0.147/kW–mo	To be calculated October 1, 1999.
Energy Imbalance	N/A	L–AS4	L–AS4

COMPARISON OF EXISTING, STEP-ONE, AND ESTIMATED STEP-THREE RATES—Continued

Class of service	Existing rate schedule and rate	Rate schedule and step-one rates April 1, 1998	Rate schedule and estimated step-three rates [1]
		For negative excursions outside of 6% bandwidth (2 MW minimum) and occurring more than 5 times per month, RMR reserves the right to charge 100 mills/kWh.	For negative excursions outside of 3% bandwidth (2 MW minimum) and occurring more than 5 times per month, RMR reserves the right to charge 100 mills/kWh.
		Positive excursions outside the bandwidth may be credited to the customer within 30 days for 50 % of the regional average monthly price for non-firm purchases.[4].	Positive excursions outside the bandwidth may be credited to the customer within 30 days for 50 % of the regional average monthly price for non-firm purchases.[4]
Spinning/Supplemental Reserves	N/A	L–AS5 and 6	L–AS5 and 6
		Long-term Reserves are not available from WACM.	Long-term Reserves are not available from WACM.
		Reserves will be provided on a pass-through cost.	Reserves will be provided on a pass-through cost.

[1] To be recalculated October 1, 1999.
[2] Rate Schedule stipulates that if an existing Transmission Customer is billed on an energy basis, the rate per capacity unit will be converted to a rate per energy unit, based on individual customer's load factor.
[3] If a Transmission Customer requires use of LAP subtransmission facilities for delivery of non-Federal energy, a specific facility use charge will be assessed.
[4] During times when over deliveries would impinge on WACM operations, RMR reserves the right to eliminate credits.

Certification of Rates

Western's Acting Administrator has certified that the LAP transmission and ancillary services rates placed into effect on an interim basis herein are the lowest possible consistent with sound business principles. The formula rates have been developed in accordance with agency administrative policies and applicable laws.

LAP Transmission Service Discussion

The charges for network and point-to-point transmission service will be implemented in three steps between April 1, 1998, and October 1, 1999. Each step will be recalculated based on the updated financial data and loads. Network service charges will be based on the Transmission Customer's load-ratio share of the annual revenue requirement for transmission. Point-to-point service will be based on reserved capacity on the transmission system.

Annual Transmission Revenue Requirement: The Annual Transmission Revenue Requirement will be applicable to both network and point-to-point transmission service.

The Annual Transmission Revenue Requirement is the Annual Transmission Cost, adjusted for revenue credits and costs associated with expenses which expand the capacity available for transmission. The formula is:

$$\begin{array}{c}\text{Annual}\\\text{Transmission}\\\text{Revenue}\\\text{Requirement}\end{array} = \begin{array}{c}\text{Annual}\\\text{Transmission}\\\text{Cost}\end{array} + \begin{array}{c}\text{Transmission Expenses}\\\text{Which Increase}\\\text{Transmission System}\\\text{Capacity}\end{array} - \begin{array}{c}\text{Miscellaneous}\\\text{Revenue}\\\text{Credits}\end{array} - \begin{array}{c}\text{Revenue Credit}\\\text{For Existing}\\\text{Contracts}\end{array}$$

Following is an estimate of the third-step revenue requirement, using FY 1996 data. This revenue requirement will be recalculated every October.

$\$43,153,308 = \$44,669,889 + \$0 - \$837,908 - \$678,671$

The Transmission Expenses Which Increase Transmission System Capacity will include any future credits paid to Transmission Customers from augmentation of the system. The credits will be addressed in the individual service agreements, and appropriate adjustments will be made in subsequent rate calculations. Western will evaluate these requests in accordance with guidance in FERC Order No. 888–A, Section IV.G.1.g: ''* * * for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid.''

Miscellaneous Revenue Credits may include, but will not be limited to non-firm, discounted firm, and short-term firm transmission sales; Scheduling, System Control, and Dispatch Service; or facility charges for transmission facility investments included in the revenue requirement. The non-firm point-to-point transmission service credit is estimated to be $788,064, based on the non-firm transmission sales made on the LAP transmission system during the time period of July 1996 to June 1997. Credits for scheduling service are estimated to be $19,540. Credits for facility charges are $30,304.

The Revenue Credit For Existing Transmission Contracts includes the transmission revenue received from PacifiCorp under Contract No. 14–06–400–2437. The loads served under this contract were excluded from the total system load. This contract is a 1-mill reciprocal agreement that requires a 3-year notification for cancellation. Western gave the required 3-year notice to PacifiCorp in May 1997. This revenue credit shall be included in the revenue requirement calculation until such time as the contract terminates. At that time, the loads will be added to the LAP Transmission System Total Load for rate determination.

The Annual Transmission Cost is the product of the Annual Fixed Charge Rate and the Net Investment Cost for Transmission Facilities. The formula is:

Annual Transmission Cost = Annual Fixed Charge Rate x Net Investment Cost for Transmission Facilities

This formula applied to FY 1996 data is:

$44,669,889 = 19.194%* x $232,731,025

The Net Investment Cost for Transmission Facilities was determined by an analysis of the LAP transmission system. Each LAP facility was identified by function: transmission, subtransmission, distribution, or generation-related. Only the investment costs of the facilities identified as ''transmission'' were used in developing the proposed transmission rates. The investment costs of facilities identified as ''subtransmission'' and ''distribution'' were allocated to LAP Federal Customers. The LAP subtransmission system is used primarily for delivery of Federal power to Federal Customers. If a Transmission Customer requires the use of the subtransmission system, an additional facility-use charge will be assessed. All costs of Fryingpan-Arkansas were considered generation-related; and therefore, included with other generated-related cost in the revenue requirement for ancillary services.

The facilities identified as performing the function of transmission include all transmission lines that are normally operated in a continuously-looped manner and the associated substations and switchyard facilities. In the LAP transmission system, these are primarily the 115-kV and 230-kV transmission lines. In addition, a portion of the communication and maintenance facilities was included in the investment costs for transmission. The total investment cost for transmission facilities, as of September 30, 1996, is $304,913,006. The allowance for depreciation on these facilities is $72,181,981, yielding a net investment cost of $232,731,025.

The Annual Fixed Charge Rate includes operation and maintenance (O&M) expenses, administrative and general expenses (A&GE), depreciation expenses, and interest expenses. The formula is:

$$\text{Annual Fixed Charge Rate} = \frac{\begin{array}{c}\text{Annual Operation}\\\text{and Maintenance}\\\text{Expenses}\end{array} + \begin{array}{c}\text{Annual Administrative}\\\text{and General}\\\text{Expenses}\end{array} + \begin{array}{c}\text{Annual}\\\text{Depreciation}\\\text{Expenses}\end{array}}{\text{Net Investment}} + \frac{\begin{array}{c}\text{Annual}\\\text{Interest}\\\text{Expenses}\end{array}}{\begin{array}{c}\text{Unpaid}\\\text{Balance}\end{array}}$$

This formula applied to FY 1996 data is:

19.194% = 6.003% + 1.647% + 3.084% + 8.460%

The source for the annual O&M, A&GE, depreciation, and interest expenses is the *Results of Operations for the Rocky Mountain Customer Service Region—Pick-Sloan Missouri Basin*. The source for the unpaid balance is the amount reported in the *Historical Financial Document in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program*.

Transmission System Load: The LAP Transmission System Total Load is the average 12-cp monthly system peak for network transmission service, the 12-cp monthly entitlements for Federal Customers, and the reserved capacity for all firm point-to-point transmission service.

The LAP Transmission System Total Load is calculated as follows, based upon 1995 data and known and measurable charges:

Federal Customers	604,505 kW
Network Transmission Customers	241,991 kW
Subtotal	819,496 kW
Point-to-Point Reserved Capacity	306,767 kW
LAP Transmission System Total Load	1,126,263 kW

This load was derived as follows:

• Obtained hourly individual revenue meter readings for delivery points on the LAP transmission system. This included all delivery points in the Firm Electric Service Contracts for Federal power, auxiliary power from a non-Federal source, project use and special customers, and third-party wheeling delivery points.

• Subtracted the meter readings for point-to-point Transmission Customers to determine the network transmission service load.

• Added the reserved capacity for point-to-point Transmission Customers to determine the LAP Transmission System Total Load.

Network Transmission Service: The monthly charge for network transmission service is the product of the Transmission Customer's load-ratio share times one-twelfth of the Annual Transmission Revenue Requirement. The customer's load-ratio share is the ratio of its network transmission load to the LAP Transmission System Total Load, which will be calculated on a rolling 12-cp basis.

The customer's network load will be derived as follows:

• Identify the LAP transmission system peak hour for each month.

• Calculate the total delivery to each individual Network Transmission Customer for the 12 monthly peak hours.

• Identify the part of the total delivery associated with each customer's monthly LAP monthly entitlement.

• Identify the network delivery during each of the 12 monthly peaks (total delivery minus monthly entitlement for delivery of Federal power).

• Sum the 12 monthly peaks and divide by 12 months to derive the 12 cp for each Network Transmission Customer.

Firm Point-to-Point Transmission Service: The proposed rate for firm point-to-point transmission service is the Annual Transmission Revenue Requirement, divided by the LAP Transmission System Total Load. Firm

*Actual percentage carried out to five decimal places.

point-to-point transmission service is available for a period of 1 day or longer.

The formula for the proposed rate is as follows:

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

Following is an estimate of the third-step rate, using FY 1996 data. This rate will be recalculated every October.

$$\$3.19/\text{kW-mo} = \frac{\$43,153,308}{1,126,263 \text{ kW}} \div 12$$

Non-Firm Point-to-Point Transmission Service: Non-firm transmission service is available for periods ranging from 1 hour to 1 month. The rate for non-firm transmission service may be discounted based on market conditions, but will never be higher than the firm point-to-point transmission rate, converted to an energy equivalent at 100 percent load factor. The formula for the non-firm transmission service rate is:

$$\text{Maximum Non-Firm Point-to-Point Transmission Rate} = \text{Firm Point-to-Point Transmission Rate}$$

Based on the Firm Point-to-Point Transmission Rate, an estimate of the maximum Non-Firm Point-to-Point Transmission Rate for the third step is:

Monthly delivery: $3.19/kW of reserved capacity per month
Weekly delivery: $0.74/kW of reserved capacity per week
Daily delivery: $0.11/kW of reserved capacity per day
Hourly delivery: 4.58 mills/kWh

Transmission Service Comments

The following comments were received during the public comment period. RMR paraphrased and combined comments when it did not affect the meaning. RMR's response follows each comment. Changes were made in the formula rates and calculations as a result of the comments noted.

Comment: In order to avoid any confusion, Western may wish to clarify that when using the term ''existing contracts'' it is referring solely to transmission contracts and is not suggesting that the unbundling provision of FERC Order No. 888 is applicable to the statutory obligations of Western.

Response: RMR agrees and has made this change in the Rate Order to avoid confusion.

Comment: One commentor is concerned that RMR has designed a single transmission service rate to apply to existing agreements which have drastically varying billing parameters. Historically, this practice of billing non-standard agreements under a single rate schedule has resulted in each Transmission Customer effectively paying a different charge per kW of annual transmission capacity reserved, with the customers being billed on annual reserved capacity paying the highest charge. On pages 10–11 of the Customer Brochure, RMR proposes to continue this inequitable treatment by billing these existing agreements and any new service provided under Western's Tariff under the same proposed rate schedule. In order to avoid under-recovery of revenue requirements, RMR has essentially allocated cost responsibility to each of its existing transmission arrangements on the basis of the disparate billing parameters specified in these agreements and ignored the annual transmission capacity reserved under these arrangements. This approach is inequitable and inconsistent with the intent of FERC Order No. 888 and causes Transmission Customers billed on annual reserved capacity to subsidize other customers on the LAP system. One of the fundamental principles established in FERC Order No. 888 is that all Transmission Customers should pay, on a comparable basis, for the full amount of the transmission capacity they reserve and/or use.

Response: RMR agrees with the commentor that the existing LAP transmission rate applied to the existing transmission agreements has resulted in Transmission Customers effectively paying different charges per kW of annual transmission capacity reserved and/or used. RMR also recognizes that because the existing LAP transmission rate was based on a projected denominator, the existing LAP rate results in Federal Customers paying about $6.9 million annually more than their comparable share of the LAP transmission costs due to unbillable projections.

RMR will correct this disparity in charging. RMR developed the formula rates under the assumption that all existing Transmission Customers will switch to service agreements under Western's Tariff. These service agreements will eliminate the disparity that currently exists.

RMR has also taken steps to eliminate the disparity even if some Transmission Customers elect to retain their existing contracts. With the exception of Contract No. 14–60–400–2437 with PacifiCorp, LAP transmission rate adjustments are implemented by changing the rate schedules which are attached to the contracts. As stated on pages 10–11 of the Customer Brochure, if an existing customer elects to retain its existing transmission contract, transmission service will continue under the conditions of the existing contract, but under the Provisional Rate Schedules. The Provisional Rate Schedules stipulate that if an existing Transmission Customer is billed on an energy (rather than capacity) basis, the rate per capacity unit will be converted to a rate per energy unit, based on the individual Transmission Customer's load factor. This stipulation and the use of 12 cp for both network and point-to-point transmission service will result in all customers (billed on capacity usage, energy usage, or reserved capacity) paying the same rate per capacity unit.

To avoid over/under recovery, RMR has developed the rate denominator (load) based on the same amount as the projected billing determinant, assuming all customers switch to service agreements. If necessary, the rate denominator will be adjusted for Step Two of the rate adjustment to reflect the appropriate load for any Transmission Customer that does not switch to a service agreement; e.g., if a customer elects to retain its existing contract and is, therefore, billed on non-coincidental peak capacity, or on an energy basis, the appropriate billing determinant will be substituted in the rate denominator. Therefore, Step One will also serve as a transition period to align all customers on a comparable basis, with no risk of over collecting.

During Step One and Step Two of the transition period, Transmission Customers will actually be paying less than their full share of transmission, with the Federal Customers making up the difference. By the end of the Step Three, equitability between Federal Customers and Transmission Customers will be achieved.

Comment: Several commentors support RMR's intent to continue to provide bundled transmission service in the firm electric service rate. One commentor states, ''The Flood Control Construction Act of 1944, which authorized the Missouri River Basin Project, required that the rate schedules be calculated with 'regard to the recovery * * * of the costs of producing and transmitting' the electric energy generated by the hydro powerplants authorized. This is a statutory prescription of bundled service.''

Response: LAP firm power rates were last adjusted in 1994, following the public process as described in 10 CFR 903. These rates were developed, consistent with the Post-1989 General Power Marketing Plan and Allocation Criteria (Marketing Plan), which established the capacity and energy available to market under Firm Electric Service Contracts. The Firm Electric Service Contracts expire in 2024.

Transmission will remain bundled in RMR's firm power rate and contracts. RMR's intent to continue to provide this service as a bundled product is consistent with FERC Order No. 888, Section IV.G.2.(a) which does not require that transmission service for bundled native load be taken under the FERC Pro Forma.

Comment: RMR has improperly designated existing transmission arrangements as network transmission service. RMR assumes that the existing bundled transmission service, included with firm preference power sales, and the existing firm transmission service, provided to certain Preference Power Customers for delivery of auxiliary power supplies in addition to RMR's scheduled sale, qualifies for rate treatment as network transmission service loads. Such rate treatment is improper because:

(1) These existing, partial requirements transmission arrangements do not meet the FERC's definition of, or requirements for, network loads, as discussed in FERC Order No. 888–A and the FERC Pro Forma, and

(2) Such treatment ignores the existing contractual arrangements that reserve a specific, and in most cases, a limited amount of transmission capacity for these deliveries.

The commentor states that the full requirements transmission deliveries associated with LAP project and special use sales are the only existing transmission service deliveries on LAP transmission system which currently qualify as network loads. LAP preference power sales are prescheduled deliveries with contractual limits that, by design, are intended to serve only a portion of the customer's load requirements.

The commentor quotes the definition of network load in the FERC Pro Forma, Section 1.22, and quotes Section IV.G.1.c.(3) and (4) of FERC Order No. 888–A in support of its position. To avoid duplicating the transmission charges, the commentor recommends RMR follow the guidelines in Section IV.G.1.c.(4).

Response: RMR has properly designated existing transmission arrangements as network transmission service. The definition of network load in the FERC Pro Forma, Section 1.22, states, ''A Network Customer may elect to designate less than its total load as network load but may not designate only part of the load at a discrete point of delivery.''

The Marketing Plan and the existing Firm Electric Service Contracts (implementing Western's statutory obligations to market Federal power) establish RMR's contractual rights for delivery of Federal long-term firm capacity and energy to electric service and project-use customers. RMR is the Transmission Customer for delivery of all long-term firm electric service.

RMR, as a Transmission Customer, has designated its entire load at the points of delivery in the Firm Electric Service Contracts as network-type service. The remaining load at each discrete point of delivery is served under a separate transmission service agreement. It is anticipated that each Transmission Customer will take service for its entire load at each discrete point of delivery in a Network Integration Service Agreement. The entire load at each discrete point will be served by network-type service.

RMR is following an alternative offered in FERC Order No. 888–A, Section IV.G.1.c.(4), to avoid double payments for transmission service. This Section states, ''The Network Customer then has two options: pursue negotiations with the transmission provider to obtain a credit on its network service bill for any separate transmission arrangements . . . in recognition of the network transmission now being provided and paid for under the tariff.''

Federal Customers will continue to pay a bundled firm power rate under their Firm Electric Service Contract. A Network Transmission Customer's network service bill will include a credit for the load designated by RMR as Firm Electric Service, and the customer will only pay network transmission service for the remainder of its loads, thereby, eliminating any duplicate charge.

Without this arrangement, LAP Transmission Customers would be precluded from receiving network transmission service, which would not allow them the comparable use of the system that RMR and others enjoy.

FERC approved a similar crediting arrangement in a ruling on a *Duke Power Company* (Duke) Case, Docket No. ER 97–2398–000, 81 FERC 61010. In this case, FERC ruled that a portion of the customers' load could be met by the Southeastern Power Administration (SEPA) allocation (which is a network transmission service) and a portion could be served under Duke's bundled service, which is of a network nature. The entire load would be served on a network basis. Payment would be made to Duke by SEPA for the SEPA Preference Customers' allocation and by the Preference Customers for the remainder of their loads. Without such arrangements, all Preference Customers of Federal power marketing administrations would be precluded from receiving network transmission service for their auxiliary supply.

Comment: In support of the above comment, the commentor states that most of the existing auxiliary transmission agreements include provisions that require RMR to make a 4-year commitment to reserve a specific amount of transmission capacity.

Response: The commentor has misinterpreted RMR's auxiliary transmission contracts. RMR's existing network-type Transmission Customers pay only for the transmission service used, not for a firm reservation, as implied by the commentor. RMR's existing network-type transmission contracts include estimates of the amount of transmission capacity required by the customer for service over and above the capacity provided under the Firm Electric Service Contracts. This estimate is similar to the 10-year forecast required in the Application for Network Integration Service, which is updated annually by the Network Transmission Customer for use in transmission planning. Also, RMR retains the right to resell any capacity not used by the Network Transmission Customer.

Comment: RMR's proposed capacity obligation is drastically understated. The commentor gives eight reasons for this statement. Each reason is addressed separately below:

Reason 1: It was the commentor's understanding that the LAP hydrogeneration resources are required, by statute, to generate at their full capacity and make every effort to avoid letting water from the reservoir bypass the generators during high water/heavy runoff conditions. RMR is then obligated to sell this excess generation output. If this understanding is accurate, then RMR should include the full output capacity of these resources as a firm reservation on the LAP transmission system, as it did in the March 1993 transmission rate study to insure that transmission capacity is available to accommodate such required generation.

Response: The commentor's understanding is inaccurate. RMR is not required to generate at full capacity. The full operating capacity of the hydrogenerators is not a valid indicator of RMR's use of the LAP transmission system. The maximum transmission capacity available to RMR for delivery of firm electric service is the total capacity under contract in the Firm Electric Service Contracts.

If high hydro conditions do occur, and the water cannot be stored in the reservoirs, RMR offers available seasonal energy first to existing Federal Customers to increase the load factor associated with their contract rate of delivery, per Section V.D.2.b. of the Marketing Plan. Any surpluses not marketed to Federal Customers will be marketed by a Western merchant function and will require point-to-point transmission under Western's Tariff. These non-firm sales on the transmission system are reflected as a revenue credit to the firm transmission revenue requirement; thereby, reducing the obligation of the other users of the system.

RMR did not use the full output capacity of its hydro resources in its 1993 transmission rate study. RMR used the P–SMBP–WD operating plant capacity at the 90-percent hydrologic probability of exceedance of 761,500 kW, which was established in the Marketing Plan. The 761,500 kW includes reserves and required maintenance which are not included in the marketable capacity.

The rate denominator should only include the amounts that are marketed and hence can be billed. Therefore, RMR included only the monthly capacities marketed under the Firm Electric Service Contracts in the rate denominator for the formula rates. These marketed capacities are the monthly capacity entitlements. It is assumed that these capacity entitlements are always used for peak monthly deliveries of firm Federal power.

Reason 2: RMR does not recognize a separate transmission obligation for the Town of Julesburg, Colorado, which established its own arrangements for firm, auxiliary transmission service with RMR under Contract No. 96–RMR–914, dated November 15, 1996.

Response: RMR agrees and has corrected the denominator to account for network transmission service to the Town of Julesburg of 1,272 kW (12 cp).

Reason 3: RMR did not recognize the October 2, 1997, revision to Exhibit B of Contract No. 88–LAO–376 with Public Service Company of Colorado (PSCo).

Response: This Exhibit B revision was made after the publication of the Customer Brochure in September 1997. RMR has subsequently changed the denominator (from 180,320 to 195,638 kW) to account for the FY 1998 reserved capacity for PSCo.

Reason 4: Several of the auxiliary transmission service agreements provide for the transmission of pumped-storage return energy, but it is not clear whether such off-peak, point-to-point transmission service is provided on a firm or non-firm basis. To the extent that such service is non-firm and the sum of the customer's firm and non-firm service deliveries never exceed the customer's firm capacity reservation, it is appropriate for RMR to provide such non-firm service without an additional charge or reservation.

Response: This network-type service is for serving network load, specifically the return of pumped-storage energy, from network resources. The transmission of pumped-storage return energy is always off-peak and, hence, does not add to the customer's usage on the system monthly peak.

Reason 5: RMR and PacifiCorp have a reciprocal obligation, under Contract No. 14–06–400–2437, to provide firm transmission service for each other at a discounted rate of 1 mill per kWh delivered. The agreement provides for a 3-year notice to terminate these arrangements, but Western did not provide such notice to PacifiCorp until May 1997. Instead of including this PacifiCorp transmission reservation (152,750 kW) in the LAP capacity obligation calculation, RMR proposes to include the test period discounted transmission revenue from this agreement as a credit to the LAP transmission revenue requirement. Under this reciprocal arrangement, Western and PacifiCorp provide discounted firm transmission service for each other that exclusively benefits the generation/power merchant functions within these organizations. Long-term, firm Transmission Customers of the LAP system are not offered similar discounted rates. Western has received less than full transmission compensation from PacifiCorp in exchange for wheeling arrangements on the PacifiCorp system which benefits Western's generation marketing efforts.

Response: This is an existing contract, which the Federal Government arranged in good faith over 20 years ago at a regionally standard rate of 1 mill/kWh. This contract did not include a provision for adjusting the rate schedule. Over the years, PacifiCorp's use of the RMR system has increased, and RMR's use of PacifiCorp's system has remained relatively constant.

The commentor has contended that RMR has benefited from the reciprocal arrangement. However, the loss of revenue to RMR has far outweighed the benefit to RMR under this contract. This contract does not exclusively benefit RMR's generation/merchant function. In 1998, PacifiCorp will provide only 12,500 kW of transmission capacity for RMR, and RMR will provide 164,500 kW of transmission capacity for PacifiCorp. RMR receives a benefit of about $230,000 per year (if RMR were to pay PacifiCorp's wheeling rate of $24.30/kW/year in place of the 1 mill/kWh). RMR is annually foregoing over $3.0 million, assuming PacifiCorp takes network transmission service. Therefore, RMR included a revenue credit in the rate design, to reflect transmission payment from PacifiCorp at a rate less than the embedded costs and excluded the loads from the denominator.

Consistent with RMR's effort to align all Transmission Customers on a comparable basis, Western has given PacifiCorp the required advance notice that this contract will be terminated in May 2000. PacifiCorp will then be required to pay the transmission rate based on embedded costs, and the loads will be added to the denominator.

Reason 6: RMR included the summer and winter monthly reservations for NPPD under Contract No. 87–LAO–200. RMR's proposed rate treatment of this transmission obligation has the effect of discriminating against Transmission Customers that purchase long-term, firm point-to-point transmission service on the basis of an annual capacity reservation and whose load patterns could be exactly like that of NPPD.

Response: It appears the commentor assumed that the NPPD contract is a long-term point-to-point contract. RMR recognizes that long-term point-to-point service is for 12 equal monthly reservations; however, NPPD has an existing contract for a seasonal reservation, and RMR must honor it for the remainder of its term. Future service agreements for unequal monthly reservations (like the service provided to NPPD) will be considered short-term point-to-point. Revenue from future short-term point-to-point service agreements will be treated as a revenue credit, and the load will be excluded from the denominator; thereby, not affecting long-term Transmission Customers.

It is anticipated that NPPD will retain its existing transmission contract; therefore, the monthly reservations for which it will pay the point-to-point rate were included in the rate denominator. Thereby, the rate design is consistent with the billing amounts in the contract and no over/under recovery will occur.

Reason 7: RMR has understated the total capacity reservation for Municipal Energy Agency of Nebraska (MEAN). Under Contract No. 89–LAO–487, Exhibit A, RMR has a firm obligation to transmit up to 1,934 kW of power and energy. Likewise, under Exhibit B, RMR is separately obligated to transmit up to 22,156 kW. It is not clear why RMR's calculation includes only the obligation in Exhibit B, but it appears that RMR has understated the total capacity reservation.

Response: MEAN has indicated that they will elect to take network transmission service. The 12 cp for MEAN has been added under network load in the rate denominator. The issue raised by the commentor, therefore, is no longer applicable.

Reason 8: RMR has a firm obligation to transmit up to 103,000 kW of power and energy for the Rocky Mountain Generation Cooperative, Inc. (RMGC). RMR's calculation shows a slightly different amount.

Response: RMGC has a firm transmission capacity reservation for 100,000 kW, to Sidney, Nebraska, which RMR included as point-to-point service. RMGC also received firm transmission service to the Town of Basin, Wyoming, and paid for the maximum service received, which is estimated by RMGC as 3,000 kW. RMR included this 12-cp load of 2,583 kW as network transmission service.

As of January 1998, transmission service from the Town of Basin was deleted from the RMGC contract and added to the Tri-State transmission agreement. RMR has made this adjustment in the rate denominator.

Comment: One commentor supports RMR's approach to pricing firm point-to-point service, which cannot be discounted, and pricing non-firm service on a maximum basis, which can then be discounted.

Response: Although RMR does not anticipate offering discounted firm point-to-point service over the LAP transmission system, Western's Tariff does allow for discounting of firm and non-firm point-to-point service, consistent with the FERC Pro Forma.

Comment: One commentor suggests that credits for augmentation facilities be included in the individual Network Integration Service Agreement for the specific customer and not be a part of the initial rate making process. Subsequent annual revisions of the transmission service rates should take augmentation credits into account in the calculation of the new rate. On the same topic, another commentor suggested that RMR work with a group of customers to define augmentation and establish criteria for determining when and where augmentation exists on the LAP transmission system. The resulting definitions and objective criteria can then be applied to instances in which augmentation is claimed. This process should occur in a manner which allows input from all affected Federal Customers. A third commentor opposes RMR granting augmentation credits unless it can be demonstrated that non-Federal transmission facilities were necessary to deliver the firm electric service to Preference Customers.

Response: In accordance with FERC Order No. 888, credits for customer-owned facilities are best resolved on a fact-specific, case-by-case basis. We agree that credits will be addressed in the individual Network Integration Service Agreement, and appropriate adjustments may be made in subsequent rate calculations. If customers feel that augmentation credits are warranted, they should submit a written request with sufficient data to support their claim. RMR will evaluate such requests, with input from all affected parties, in accordance with guidance in FERC Order No. 888–A, Section IV.G.1.g: ''* * * for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid.''

Comment: In RMR's cost of capital determinations, it applies the composite interest rate on outstanding debt to the entire net plant investment, rather than just to the unpaid component of the net investment. By doing so, it creates an ongoing financing cost for the principal component of the net investment that has already been paid back to the U.S. Treasury. Since there is no cost associated with the repaid principal component and since these governmental entities have no equity owners that have invested capital, such treatment is improper and overstates the true cost of capital.

Response: Although the revenue requirement includes interest charges on the entire amount of undepreciated plant, no ongoing finance charge is being created through its calculation. The methodology merely ensures that transmission users pay finance charges related to the plant they use. These finance charges are reduced over time by the amount of plant investment removed to accumulated depreciation or retirements. As these investments reduce in value, so do the financing charges associated with them.

By applying an interest component to plant that has already been paid but not yet depreciated, RMR is recognizing prepayments made by Federal Customers and revenues from surplus generation sales that have been applied against outstanding transmission debt. Western's repayment of these investments is governed by DOE Order RA 6120.2, which prescribes repayment of revenues to the highest interest-bearing project investments first, regardless of whether they are related to transmission or generation. This makes it possible for principal to be significantly reduced on transmission debt without payment by transmission users. If the interest component is not applied to net plant, the Transmission

Customers would not pay their share of the interest expense.

Western revenues repay projects whose resources are entirely hydro; therefore, average water is used to forecast repayment revenues. This means that some years will have high-energy sales that can be used to prepay debt in anticipation of drought conditions, such as those from 1988 through 1993, when revenues were insufficient to meet LAP's repayment obligations. These prepayments act as stabilizing factors during the ebb and flow of hydrologic cycles to ensure repayment of project obligations. RMR's transmission rates have never included charges for interest deficits, O&M deficits, or purchase power arising from poor water years. RMR believed that these expenses were related to insufficient energy to meet its obligations, and the associated costs were incorporated in the firm power rate. It would be inappropriate for Transmission Customers to share the benefit of good water, but none of the costs of poor water.

Comment: Revenues derived from third-party transmission service transactions should be accounted for in future repayment.

Response: In accordance with the DOE Order RA 6120.2, all transmission revenues are credited to the P–SMBP power repayment study, including an estimate of future revenues to reflect this transmission rate adjustment.

Comment: A commentor has taken issue with the way that RMR has functionally allocated the LAP microwave communications system and the Power Marketing and Operations Complex (PMOC). By functionally allocating the investment of these two facilities on the basis of LAP plant investment, which includes almost no generation-related plant, RMR understates the amount of service provided to the generation/power merchant function by assigning a disproportionately large amount of the annual cost of these items to transmission. The commentor recommends including the net plant investment costs of Reclamation in calculating the functional allocation of RMR's costs.

Response: Although Western and Reclamation are both agencies of the Federal Government, they function as distinct and separate entities, both financially and functionally. On December 21, 1977, under Section 302 of the Department of Energy Organization Act, Congress established Western, whose primary responsibility is power marketing and transmission of the Federal generation resource. These transferred responsibilities were previously held by Reclamation, who continues to own, operate, and maintain the generation resources for the Federal Government.

With regard to the commentor's issue concerning the microwave communications allocation, Reclamation owns, operates, and maintains its own Supervisory Communications and Data Acquisition (SCADA) system for microwave communications, none of which is included in the transmission rate. The cost of Reclamation's SCADA facilities are in the RMR's calculations for the generation based ancillary services. RMR's SCADA and microwave communications system is designed, operated, and maintained by RMR personnel primarily for transmission system use. Therefore, RMR asserts that its allocation of SCADA and microwave communications costs on the basis of LAP investment is proper.

With regard to the PMOC, RMR revisited its computation for functionally allocating the PMOC costs. RMR's methodology for this review was an analysis of PMOC office space, and specifically, what percentage of the office space is occupied by personnel that support the generation function. RMR found that based on space occupied in the PMOC by generation-dedicated employees, the amount of the PMOC to be functionally allocated to generation should be 2.928 percent, rather than the 3.669 percent derived from investment costs. Reallocation of the PMOC to accommodate this .741 percentage difference increases the amount allocated to transmission by $176,080. This is insignificant when contrasted against the total transmission allocation of $304,913,006. Given the relatively insignificant amounts and immaterial rate impacts, RMR maintains that its original allocation of the PMOC building costs based on LAP plant investment is reasonable.

Comment: One commentor also feels that RMR should use cost-tracking allocators to functionally assign expenses, rather than allocating on the basis of the LAP net investment. Specific FERC accounts should be functionally allocated on the basis of what function they benefit. A&GE expenses associated with field-type offices that provide multi-function services should be functionally allocated using a basis that fully recognizes the generation/power merchant function performed at these offices. The commentor points out that certain O&M expense items, specifically the Conservation and Renewable Energy (C&RE) Expense and the Power Marketing and Generation Power Resources Planning Expense, should be entirely excluded from the transmission revenue requirement and assigned specifically to the generation/power merchant function at RMR.

Response: As previously stated, Western's primary responsibility is the power marketing and transmission of the Federal generation resource. RMR provides only incidental generation support. Reclamation owns, operates, and maintains the generation resource for the Federal Government. Reclamation costs have not been included in the transmission revenue requirements.

Western undertook a line item analysis of the O&M costs. Western agrees with the commentor that the cost of C&RE could be completely assigned to the generation function. Adjustments could be made to the line items for Power Users Account and Collection Expenses and Power Marketing and Generation Power Resources Planning Expenses, which would increase the 3.669 percent allocated to generation. However, these three adjustments amount to a decrease in the O&M allocated to transmission by $317,455, which would reduce the fixed charges for transmission by less than 0.1 percent. Given the relatively insignificant amounts and immaterial rate impacts, RMR will continue to functionally allocate the LAP O&M and A&GE costs based upon plant investment costs. RMR reiterates that Western staff do not perform significant generation activity.

During RMR's review of the O&M costs, an extensive reexamination of those costs was undertaken and a determination was made that the Mt. Elbert Powerplant O&M was classified inappropriately in the original calculations. The original calculations assumed that Mt. Elbert was only used for the provision of firm power; in fact, Mt. Elbert is actually used to provide a material amount of Regulation and Frequency Response Service and Reserves support. Therefore, RMR's costs for the O&M of Mt. Elbert, which were originally allocated to LAP Federal Customers, are now being included in the Annual Fixed Charge Rate for Generation. This adjustment increases the generation O&M costs by $3 million, the addition of which yielded no impact to the ancillary service rates.

Comment: RMR included in the transmission revenue requirement the charges it pays to NPPD for transmission service under Contract No. 87–LAO–200. The transmission service from NPPD provides no long-term, firm transmission capacity to RMR beyond that which is required and reserved to serve RMR's firm generation service loads located in southern Nebraska and northern Kansas and which are captive to the NPPD transmission system. Consequently, the long-term firm Transmission Customer on the LAP transmission system can derive no benefit from this wheeling arrangement. To be consistent with the functional unbundling requirements, this wheeling arrangement should belong to the generation/power merchant function.

Response: RMR agrees and has eliminated this item from the numerator of the rate design calculation.

Comment: RMR transmission rate proposal does not include any revenue credit for the lease of facilities that have been included in the functionalized LAP transmission plant investment.

Response: RMR reviewed all revenue from rental of facilities, which are included in the transmission plant investment. Such revenues are about $30,000, annually. These revenues have been included as a revenue credit in the numerator.

Comment: One commentor supports separating the cost of subtransmission facilities from the transmission rate. Clearly these facilities are not part of the bulk supply system, but are used to serve local loads, and, therefore, should be paid for separately.

Response: RMR agrees and assigned the subtransmission to the Federal Customers. The subtransmission system is used primarily for delivery of Federal power to the Federal Customers. If a Transmission Customer requires the use of the subtransmission system, an additional facility-use charge will be assessed.

Comment: The primary reason for the increase in the transmission rate was due to a change in the denominator. One customer recognized that a large portion of this change was because some customers included their Federal load in the transmission load projections they provided to Western for the 1993 transmission rate. This overstated the denominator. This commentor suggested that when submitting to FERC, RMR should include data showing how the loads change by customer.

Response: The suggested information has been provided in the supporting data to this Rate Order. The transmission rate has been understated since 1994. Western has corrected the rate so that the transmission revenue requirement will be collected.

Comment: One commentor supports RMR keeping its firm power rate bundled, but is concerned that RMR may not meet the comparability requirements of FERC Order No. 888 because it does not charge itself for transmission service, including all wholesale power deliveries to Preference Customers, the same rate as it will charge others for use of the transmission system.

Response: Firm Federal power is transmitted as a network-type service under existing bundled Firm Electric Service Contracts, and not under Western's Tariff. RMR uses whatever power or transmission is required to meet its Firm Electric Service Contract commitments, like network transmission service.

RMR believes that it meets the comparability requirement of FERC Order No. 888. In FERC Order No. 888–A, Section IV.C.b., it is clarified that the transmission provider must ''take service'' under its own tariff for third-party sales for comparability. RMR's merchant function will take service under Western's Tariff and point-to-point rates for any third-party sales.

FERC Order No. 888–A recognizes that existing contracts will not necessarily be at the same rate as the transmission service offered under the Tariff. However, the service can still be considered comparable. RMR has shown in its rate design for this Rate Order that the calculation of transmission costs for delivery to Federal Customers is on the same basis as for other firm Transmission Customers.

Comment: Several commentors support RMR's phased-in approach to reach its required transmission rate level, as a means to mitigate the rate shock associated with the large rate increase.

Response: RMR proposed a three-step approach to implement the transmission rate increase between April 1, 1998, and October 1, 1999.

Comment: The commentor commended Western for its thoughtful approach in developing the proposed transmission rates and the thorough public process associated with encouraging comment from affected parties and interested members of the public.

Response: RMR appreciates the input from its customers during the public process.

Ancillary Services Discussion

Six ancillary services will be offered by WACM; two of which are required to be purchased by the LAP Transmission Customer. These two are: (1) Scheduling, System Control, and Dispatch Service, and (2) VAR Support. The remaining four ancillary services—Regulation, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves—will also be offered, but are subject to availability.

Sales of Regulation, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves may be limited since Western has allocated its power resources to preference entities under long-term commitments. If WACM is unable to provide these services from its own resources, an offer will be made to purchase the services and pass through these costs to the customer, including an administrative charge.

The formula rates for ancillary services will be based on the costs of WACM control area and are designed to recover only the costs associated with providing the service(s).

The WACM, as of April 1, 1998, will have a single control office, combining the offices that formerly controlled the Western Area Upper Colorado control area (WAUC) and the Western Area Lower Missouri control area (WALM). WACM Federal power resources consist of all the LAP Federal power resources and a portion of the Salt Lake City Area-Integrated Projects (SLCA–IP) Federal power resources.

Scheduling, System Control, and Dispatch Service: The costs for providing Scheduling, System Control, and Dispatch Service for Transmission Customers are included in the appropriate transmission service rates. This service can be provided only by the control area operator in which the transmission facilities are located. The formula rates will be applied to all schedules for WACM non-transmission customers.

The formula rate for Scheduling, System Control, and Dispatch is based on the annual cost of all personnel and related cost involved in providing the service for WACM. The annual cost is divided by the number of schedules per year to derive a ''rate per schedule'' applied per day. RMR's definition of a ''schedule'' is a specific request for energy or transmission through, within, into, or out of WACM, per day. The entity requesting the schedule is generally the entity responsible for the scheduling charge, unless other arrangements are made.

RMR will accept any reasonable number of schedule changes over the course of a day, without any additional charge, so that entities trying to follow their loads closely may do so without penalty.

Based on FY 1996 data, the rate for WACM, effective April 1, 1998, will be $25.71 per schedule per day.

Reactive Supply and Voltage Control Service from Generation Sources: The formula rate for VAR Support is based upon Reclamation's net generation plant investment in WACM. Annual Fixed Charge Rates based on annual generation-related O&M, A&GE, depreciation, and interest expenses for LAP and for SLCA–IP are applied to Reclamation's net generation plant investment to calculate annualized costs. The percentage of WACM generation capacity that is utilized for VAR Support is then identified. This percentage is applied to the annualized costs for LAP and SLCA–IP, and those results summed to derive the annual revenue requirement for VAR Support for WACM. The annual revenue requirement is then divided by the WACM 12-cp load being provided VAR Support, to yield a $/kW-year rate, which is divided by 12 months to yield a kW-month rate. Based upon FY 1996 data, the WACM rate for VAR Support is $0.112/kW-month.

Credit may be given to those customers with generators in the control area providing WACM with VAR Support. Any crediting arrangement must be documented in the customers' service agreements.

Regulation and Frequency Response Service: The formula rate for Regulation is based upon the annualized cost of Reclamation's net plant investment for regulating plants in WACM (the investment costs for SLCA–IP regulating plants that will provide Regulation in the Western Area Lower Colorado control area were not included). The net investment costs were included for only those plants that are able to provide regulating service—run-of-the-river plants were excluded because regulation control is not possible from those plants. The same Annual Fixed Charge Rates used in the VAR Support formula were used to convert the LAP and SLCA–IP net plant investments to annual costs for Regulation. The annual costs are divided by the nameplate capacity of the applicable plants to yield an average cost per kilowatt for LAP and SLCA–IP.

The amount of capacity used to provide Regulation service is identified. For LAP, one-half of the percentage of the resource used to provide Regulation is multiplied by the load in the control area requiring Regulation. For SLCA–IP, historical operational experience shows that the amount of capacity provided for the SLCA–IP load is 40 MW. The April 1, 1998, division of the SLCA–IP load into two control areas, discussed previously, has been determined to represent a 50/50 split of the load, and therefore, the capacity amount applicable to the WACM from SLCA–IP is 20 MW.

The average cost per kilowatt for LAP and SLCA–IP is then multiplied by the appropriate amounts of capacity providing Regulation, to yield the annual revenue requirements for Regulation. The annual revenue requirements are then summed and divided by the load in the control area requiring Regulation service. This yields a rate per kW-year, which is divided by 12 months to calculate a rate per kW-month. Based upon FY 1996 data, the WACM rate for Regulation is $0.147/kW-month.

Federal Customers will receive a credit for Regulation on their power bill if they receive Regulation from another source, or self-supply it for their own load. Credit will also be given to those customers who provide WACM with Regulation. These types of crediting arrangements must be documented in the Transmission Customers' service agreements.

Energy Imbalance Service: FERC established guidelines for Energy Imbalance Service of +/−1.5 percent hourly deviation (3 percent bandwidth) with a 2 MW minimum deviation, as in their view, anything more or less than that could affect the reliability of the system. RMR established the 3 percent bandwidth for Energy Imbalance Service to be consistent with FERC.

RMR recognizes that metering inadequacies, revision of scheduling practices, and unit control problems may initially hinder a customer's ability to meet the 3 percent bandwidth. Therefore, RMR is phasing in the Energy Imbalance Service bandwidth simultaneously with the transmission service rate to allow a transition period; whereby, customers may improve their equipment and scheduling practices. Effective April 1, 1998, the bandwidth will be set at 6 percent (+/−3 percent deviation); effective October 1, 1998, the bandwidth will drop to 5 percent (+/−2.5 percent); and effective October 1, 1999, the bandwidth will be in compliance with the FERC-endorsed bandwidth of 3 percent (+/−1.5 percent). Deviation accounting will be completed monthly on an hour-to-hour basis.

RMR reserves the right to assess negative excursions (under deliveries) outside the bandwidth and occurring more than five times per month, a penalty charge of 100 mills/kWh.

During normal water conditions, any positive excursions (over deliveries) outside the bandwidth will be credited on the customer's bill, lagged by 1 month. The credit will be 50 percent of the regional average monthly price for non-firm purchases, provided that these over deliveries do not impinge on WACM operations. For example, during times of high water conditions, RMR will reserve the right to eliminate any credits for over deliveries.

Spinning/Supplemental Reserves: Based upon the Post-1999 Resource Study (July 1995), WACM has no long-term Reserves available beyond its own internal requirements.

An offer will be made to purchase Reserves for a customer and pass through that cost, plus an amount for administration.

When Reserves are called on for Emergency Use, RMR will assess a charge for energy used, at the greater of 30 mills/kWh or the prevailing market energy rate in the region. The customer would be responsible for providing the transmission to get the Reserves to its destination.

Ancillary Services Comments

RMR received written comments concerning the ancillary services during the public comment and consultation period. These comments have been paraphrased where appropriate, without compromising the meaning of the comment. Certain comments were duplicative in nature, and were combined. RMR's response follows each comment.

Comment: A commentor believes that the load determinants for Regulation and VAR Support, as referenced on page 38 of the Customer Brochure, are understated for the following reasons.

For VAR Support, RMR has not accounted for Missouri Basin Power Pool, Tri-State, and CSU generation within the WALM control area. Likewise, RMR has not accounted for Craig, Nucla, Qualifying Facilities, small hydro, and other western Colorado generation that will be located in WACM.

Since VAR Support is a required service, why did RMR remove Black Hills Power and Light's (Black Hills) load from the denominator?

For Regulation, RMR has not accounted for all PacifiCorp, Tri-State, municipal, and Rural Electric Association (REA) loads located in the WALM control area. Likewise, RMR has not accounted for any non-Federal, western Colorado, Tri-State, municipal and REA loads located in WACM.

Response: Page 38 of RMR's Customer Brochure incorrectly identified ''Tri-State Direct (in WALM)'' with a number that was actually representative of cumulative ''other'' load in WACM. RMR did, in fact, include the loads that the commentor believes were omitted; i.e., Missouri Basin Power Pool, Tri-State, CSU, PacifiCorp, municipal, and REA. RMR also accounted for the western Colorado generation that will be located in WACM.

Based upon this commentor's statements, however, Western revisited and reconfirmed the load denominator for both VAR Support and Regulation service for the ''other'' load in the control area, and has refined them to be 1,047,979 kW for Regulation and 1,538,608 kW for VAR Support, as contrasted with the loads in the Customer Brochure of 1,407,917 kW for Regulation and 1,437,638 kW for VAR Support.

Black Hills' load was omitted from the VAR Support service load as they cannot receive this service from a WACM generation source. Load data for Black Hills were accounted for as part of the Regulation load, as they are in WACM's control area and RMR has a specific contract with Black Hills to provide them Regulation service. RMR also reassessed the 277 MW included in the Regulation load for Black Hills as RMR does not provide Regulation for Black Hill's total load. Based upon bills submitted in 1997, the average amount of load that RMR regulates for Black Hills is 89 MW. In conjunction with this adjustment to Black Hill's Regulation load, RMR included a $90,000 revenue credit for the existing contract for Regulation service.

Comment: A commentor is concerned about the narrow bandwidth (+/-1.5 percent) allowed for deviation from scheduled transactions, maintaining that it will be extremely difficult to stay within this bandwidth because of limitations and errors in metering, scheduling practices, and unit control.

This same commentor also requests that generating entities within the control area also be given the opportunity to participate with Western in the provision of Energy Imbalance Service, rather than merely taking the service from RMR as the control area operator.

Response: FERC has established guidelines for Energy Imbalance Service of +/-1.5 percent deviation (or 3 percent bandwidth), as in their view, anything more or less than that could affect the reliability of the system. RMR established a bandwidth for Energy Imbalance Service to be consistent with FERC and with what the industry has been using as a standard.

RMR points out to its customers that FERC did establish a larger minimum deviation of 2 megawatts (MW) in an attempt to meet the needs of smaller customers. This minimum allows Transmission Customers with load less than 133 MW to have more flexibility in the bandwidth.

However, RMR does recognize that some of its customers may construe the 3 percent bandwidth as too narrow, from the perspective that there are currently limitations in metering, scheduling practices, and unit control. Therefore, RMR is phasing in the Energy Imbalance Service bandwidth simultaneously with the transmission service rate to allow a transition period; whereby, customers may improve their equipment and revise their scheduling practices. Effective April 1, 1998, the bandwidth will be set at 6 percent (+/-3 percent deviation); effective October 1, 1998, the percentage bandwidth will drop to 5 percent (+/-2.5 percent deviation); and effective October 1, 1999, the percentage bandwidth will be in compliance with the FERC-endorsed bandwidth of 3 percent (+/-1.5 percent deviation).

Regarding participation in the provision of Energy Imbalance Service by others in WACM, RMR asks that any proposals submitted to RMR demonstrate the benefits to the control area in terms of Energy Imbalance Service (deviation, inadvertent flow, and losses), and reliability for operation of the control area.

Comment: A commentor recommends that the provision limiting schedule changes be eliminated. They also recommend a more rigorous definition of the term ''schedule'' as it is applied in this rate. The commentor noted that it may be worthwhile to consider an exhibit to the service agreement that would identify billable schedules.

Response: In its initial rate design, RMR developed its Scheduling, System Control, and Dispatch Service rate and limited the number of schedule changes to five times per day before any additional scheduling charge would be assessed. Schedule changes equate to the use of personnel and associated cost, and RMR was trying to both accommodate the customer and recover the cost of doing business.

However, RMR has recognized that any limit on the number of schedule changes per day may penalize entities trying to follow their loads closely. Therefore, RMR will accept any reasonable number of schedule changes over the course of the day without additional charges.

RMR's definition of a ''schedule'' is a specific request for energy or transmission through, into, within, or out of WACM, per day. The entity requesting the schedule is generally the entity responsible for the scheduling charge, unless other arrangements are made.

The comment concerning inclusion of an exhibit to the individual service agreements is outside the rate adjustment process; however, RMR will consider the inclusion of this exhibit to the individual service agreements identifying billable schedules.

Comment: A commentor asks that RMR and Upper Great Plains Region (UGPR) be consistent on policy for Energy Imbalance Service.

Response: RMR and UGPR are separate regional offices of Western within separate control areas, and as such, have disparate operational requirements. Additionally, the UGPR operates with basically one drainage basin, while LAP has five basins within its operational control.

LAP's five basins allow for greater operational flexibility than UGPR's main-stem system; e.g., during high water conditions, WACM would be less likely to be forced to spill and potentially lose energy. RMR has indicated that it would credit the customer for 50 percent of the regional average monthly price for non-firm purchases in a scheduled over delivery; however, RMR will reserve the right to eliminate credits during times when over deliveries would impinge upon WACM operations. RMR has revised its Energy Imbalance Service rate language accordingly.

Comment: A commentor expresses concern that care be taken to see that all revenues for ancillary services are credited back to the firm electric service rate.

Response: Western is developing procedures for proper accounting classification of Open Access Transmission revenues. RMR will assure that all revenues, including ancillary services, are incorporated in the P–SMBP Power Repayment Study, and revenues will be applied pursuant to DOE Order No. RA 6120.2.

Comment: A commentor wants to ensure that RMR views the ancillary services as an integral component of the Federal Government's power allocation. It is the commentor's position that the provision of any generation-related ancillary services which interfere with the statutory obligations of Western to dedicate its generation resources to Federal Customers is statutorily prohibited. Specifically, concerning Regulation and Reserves, Western should limit itself to providing these services to non-Federal customers only after first offering the resource to its Federal Customers. Otherwise, Western should limit the offer of these services to the brokering of ancillary services from third-party providers. Further, concerning Reserves and the selling of short-term Reserves when available, Western should affirm that if and when such Reserves are available on a short-term basis, they will be offered to Federal Customers first.

Response: Western views the ancillary services as an integral component of the Federal Government's power allocation and is not changing this viewpoint with the advent of FERC Order No. 888. Western will not take any actions that would compromise its ability to meet its contractual obligations to its Federal Customers. RMR will continue to provide all of the services so designated as approved in the Marketing Plan.

While ancillary services were not specifically defined or offered in the Marketing Plan, those services are presumed to be included in the allocation and delivery of RMR's firm power resource. RMR has fully allocated all firm resources through the Marketing Plan and currently provides all of the required ancillary services for the Federal Customers.

As stated previously, the RMR Post-1999 Resource Study ascertained that there are no long-term Reserves available from WACM resources beyond WACM internal requirements. Historically, when Western has had non-firm, short-term, or surplus resources available for sale, they have been sold on the open market. RMR has offered surplus energy first to those with Firm Electric Service Contracts, but it is an option that surplus energy be sold on the open market, as Western's UGPR and Colorado River Storage Project Customer Service Center have done. The Marketing Plan allows the sale of non-firm, short-term, or surplus resources in Section B.3.c., Marketing Considerations.

RMR has engaged in the marketing of ancillary services prior to this filing, as evidenced by RMR's provision of interconnected operation service (shaping and storage service) for RMGC, and RMR's provision of Regulation service for Black Hills. These products have been offered to both preference and non-preference customers.

Comment: A commentor applauded RMR's stance that only the ancillary services that are surplus to those required to meet Western's statutory requirements would be offered for sale. The commentor agreed with RMR's position regarding the purchase and pass through of costs for ancillary services, when not available from a control area resource.

Response: RMR appreciates the comment.

Regulatory Flexibility Analysis

Pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601–612), each agency, when required by 5 U.S.C. 553 to publish a proposed rule, is further required to prepare and make available for public comment an initial regulatory flexibility analysis to describe the impact of the proposed rule on small entities. In this instance, the initiation of the LAP transmission rate and ancillary service rate adjustment is related to non-regulatory services provided by Western at a particular rate. Under 5 U.S.C. 601(2), rules of particular applicability relating to rates or services are not considered rules within the meaning of the Act. Since the LAP transmission rates and ancillary service rates are of limited applicability, no flexibility analysis is required.

Environmental Evaluation

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

DOE has determined that this is not a significant regulatory action because it does not meet the criteria of Executive Order 12866, 58 FR 51735. Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Submission to Federal Energy Regulatory Commission

The formula 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, approve, and place into effect on an interim basis, effective April 1, 1998, formula rates for transmission and ancillary service under Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, and L–AS6. These schedules, in total, supersede Rate Schedules L–T3 and L–T4. The rate schedules shall remain in effect on an interim basis, pending FERC confirmation and approval of them or substitute formula rates on a final basis through March 31, 2003.

Dated: March 23, 1998.

Elizabeth A. Moler,

Deputy Secretary.

Rocky Mountain Region, Loveland Area Projects—Rate Schedule L–AS1 (Supersedes L–T3) Schedule 1 to Tariff April 1, 1998

Scheduling, System Control, and Dispatch Service

Applicable

This service is required to schedule the movement of power through, out of, within, or into the Western Area Colorado Missouri control area (WACM). The charges for Scheduling, System Control, and Dispatch Service are to be based on the rate referred to below. The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The rate will be applied to all schedules for WACM non-transmission customers. The Rocky Mountain Region (RMR) will accept any reasonable number of schedule changes over the course of the day without any additional charge.

The Loveland Area Projects charges for Scheduling, System Control, and Dispatch Service may be modified upon written notice to the customer. Any change to the charges for the Scheduling, System Control, and Dispatch Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. RMR shall charge the non-transmission customer in accordance with the rate 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

$$\text{Cost per Schedule} = \frac{\text{Annual Cost of Scheduling and Dispatch Personnel, and Related Costs}}{\text{Number of Schedules per Year}}$$

* * * * *

Rate

The rate to be in effect April 1, 1998, through September 30, 1998, is $25.71 per schedule per day. This rate is based on the above formula and on FY 1996 data. A recalculated rate will go into effect every October based on the above formula and data.

Rate Schedule L–AS2 (Supersedes L–T3 and L–T4) Schedule 2 to Tariff April 1, 1998

Reactive Supply and Voltage Control from Generation Sources Service

Applicable

In order to maintain transmission voltages on all transmission facilities within acceptable limits, generation facilities under the control of the Western Area Colorado Missouri control area (WACM) are operated to produce or absorb reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (VAR Support) must be provided for each transaction on the transmission facilities. The amount of VAR Support that must be supplied with respect to the Customer's (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission systems within the WACM) transaction will be determined based on the VAR Support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by WACM.

The Customer must purchase this service from the WACM operator. The charges for such service will be based upon the rate referred to below.

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

The LAP charges for VAR Support may be modified upon written notice to the Customer. Any change to the charges for VAR Support 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. The Rocky Mountain Region shall charge the Customer in accordance with the rate then in effect.

Credit may be given to those Customers with generators in the control area providing WACM with VAR Support. Any crediting arrangements must be documented in the customer's service agreement.

Effective

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

Formula Rate

$$\begin{array}{c}\text{WACM}\\ \text{VAR Support}\\ \text{Rate}\end{array} = \frac{\begin{array}{c}\text{Total Annual Revenue Requirement}\\ \text{for Generation} \times \text{Percentage of Resource Capacity}\\ \text{Used for VAR Support}\end{array}}{\text{Load in the Control Area Requiring VAR Support}}$$

* * * * *

Rate

The rate to be in effect April 1, 1998, through September 30, 1998, is:

Monthly: $0.112/kW-month
Weekly: $0.026/kW-week
Daily: $0.004/kW-day
Hourly: 0.154 mills/kWh

This rate is based on the above formula and on FY 1996 financial and load data. A recalculated rate will go into effect every October based on the above formula and updated financial and load data.

Rate Schedule L–AS3 (Supersedes L–T3) Schedule 3 to Tariff April 1, 1998

Regulation and Frequency Response Service

Applicable

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources, generation, and interchange, with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation is accomplished by committing on-line generation whose output is raised or lowered, predominantly through the use of automatic generating control equipment, as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Western Area Colorado Missouri control area (WACM) operator. The Customer (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission systems within WACM) must either purchase this service from WACM or make alternative comparable arrangements to satisfy its Regulation obligation. The charges for Regulation are referred to below. The amount of Regulation will be set forth in the service agreement.

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

The LAP charges for Regulation may be modified upon written notice to the Customer. Any change to the Regulation charges 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. The Rocky Mountain Region (RMR) shall charge the Customer in accordance with the rate then in effect.

Customers will receive a credit for Regulation on their power bill if they receive Regulation from another source, or self-supply it for their own load. Credit will also be given to those Customers who provide WACM with Regulation. These types of crediting arrangements must be documented in the customer's service agreement.

Effective

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

Formula Rate

* * * * *

$$\begin{array}{c}\text{WACM}\\ \text{Regulation}\\ \text{Rate}\end{array} = \frac{\text{Total Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Rate

The rate to be in effect April 1, 1998, through September 30, 1998, is:

Monthly: $0.147/kW-month

Weekly: $0.034/kW-week

Daily: $0.005/kW-day

This rate is based on the above formula and on FY 1996 financial and load data. A recalculated rate will go into effect every October based on the above formula and updated financial and load data.

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

Rate Schedule L–AS4, (Supersedes L–T3), Schedule 4 to Tariff, April 1, 1998.

Energy Imbalance Service

Applicable

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within the Western Area Colorado Missouri control area (WACM) over a single hour. The Customer (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission system within WACM) must either obtain this service from WACM or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation.

The WACM shall establish a deviation band of +/−3.0 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Customer's scheduled transaction(s). Deviation accounting will be completed monthly on an hour-to-hour basis.

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

The Energy Imbalance Service compensation may be modified upon written notice to the Customer. Any change to the Customer compensation for Energy Imbalance Service shall be as set forth in a revision to this schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. The Rocky Mountain Region (RMR) shall charge the Customer in accordance with the rate 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

For negative excursions (under deliveries) outside the bandwidth and occurring more than five times per month, RMR reserves the right to assess a penalty charge of 100 mills/kWh.

For positive excursions (over deliveries) outside the bandwidth, the Customer will be credited on the customer's bill, lagged by 1 month. The credit will be 50 percent of the regional average monthly price for non-firm purchases, provided the over deliveries do not impinge upon WACM operations. For example, during times of high water or operating constraints, RMR reserves the right to eliminate credits for over deliveries.

* * * * *

Rate

The bandwidth in effect April 1, 1998, through September 30, 1998, is 6 percent (+/−3 percent hourly deviation).

Rate Schedule L–AS5 (Supersedes L–T3), Schedule 5 to Tariff, April 1, 1998.

Operating Reserve—Spinning Reserve Service

Applicable

Spinning Reserve Service (Reserves) is needed to serve load immediately in the event of a system contingency. Reserves may be provided by generating units that are on-line and loaded at less than maximum output. The Customer (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission system within Western Area Colorado Missouri control area (WACM)) must either purchase this service from WACM or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are referred to below. The amount of Reserves will be set forth in the service agreement.

Effective

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

Formula Rate

No long-term Reserves are available beyond internal WACM requirements.

* * * * * *

Rate

There are no long-term Reserves available from WACM. An offer will be made to purchase Reserves for a Customer and pass through the cost, plus an amount for administration.

In the event that Reserves are called upon for Emergency Use, the Rocky Mountain Region (RMR) will assess a charge for energy used, at the greater of 30 mills/kWh or the prevailing market energy rate in the region. The Customer would be responsible for providing the transmission to get the Reserves to its destination.

Rate Schedule L–AS6 (Supersedes L–T3) Schedule 6 to Tariff April 1, 1998

Operating Reserve—Supplemental Reserve Service

Applicable

Supplemental Reserve Service (Reserves) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Reserves may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Customer (Loveland Area Projects' Transmission Customers and customers on others' transmission system within Western Area Colorado Missouri control area (WACM)) must either purchase this service from WACM or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are referred to below. The amount of Reserves will be set forth in the service agreement.

Effective

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

Formula Rate

No long-term Reserves are available beyond internal WACM requirements.

* * * * *

Rate

There are no long-term Reserves available from WACM. An offer will be made to purchase Reserves for a Customer and pass through the cost, plus an amount for administration.

In the event that Reserves are called upon for Emergency Use, the Rocky Mountain Region will assess a charge for energy used, at the greater of 30 mills/kWh or the prevailing market energy rate in the region. The Customer would be responsible for providing the transmission to get the Reserves to its destination.

Rate Schedule L–FPT1 (Supersedes L–T3) Schedule 7 to Tariff April 1, 1998

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

Applicable

The Transmission Customer shall compensate Rocky Mountain Region (RMR) each month for Reserved Capacity pursuant to the applicable

Firm Point-to-Point Transmission Service Agreement and rates referred to below. The formula rates used to calculate the charges for service under this schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

RMR may modify the charges for Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Firm Point-to-Point 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 rate then in effect.

Discounts

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

Effective

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

Formula Rate

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

* * * * *

$$\begin{array}{c}\text{Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array} = \frac{\text{Annual Transmission Revenue Requirement}}{\text{LAP Transmission System Total Load}}$$

Rate

The rate to be in effect April 1, 1998, through September 30, 1998, is as follows.

Maximum of:

Yearly: $27.84/kW of reserved capacity per year

Monthly: $2.32/kW of reserved capacity per month

Weekly: $0.54/kW of reserved capacity per week

Daily: $0.08/kW of reserved capacity per day

This rate is based on the above formula and FY 1996 data. A recalculated rate will go into effect every October based on the above formula and updated financial and load data.

Rate Schedule L–NFPT1 (Supersedes L–T4)
Schedule 8 to Tariff April 1, 1998

Non-Firm Point-to-Point Transmission Service

Applicable

The Transmission Customer shall compensate Rocky Mountain Region (RMR) for Non-Firm Point-to-Point Transmission Service pursuant to the applicable Non-Firm Point-to-Point Transmission Service Agreement and rate referred to below. The formula rates used to calculate the charges for service under this schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

RMR may modify the charges for Non-Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Non-Firm Point-to-Point 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 rate then in effect.

Discounts

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

Effective

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

Formula Rate

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$$\begin{array}{c}\text{Maximum Non-Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array} = \begin{array}{c}\text{Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array}$$

Rate

The rate to be in effect April 1, 1998, through September 30, 1998, is:

Maximum of:

Monthly: $2.32/kW of reserved capacity per month

Weekly: $0.54/kW of reserved capacity per week

Daily: $0.08/kW of reserved capacity per day

Hourly: 3.33 mills/kWh

This rate is based on the above formula and FY 1996 data. A recalculated rate will go into effect every October based on the above formula and updated financial and load data.

Rate Schedule L–NT1 (Supersedes L–T3)
Attachment H to Tariff April 1, 1998

Annual Transmission Revenue Requirement for Network Integration Transmission Service

Applicable

The Transmission Customer shall compensate the Rocky Mountain Region (RMR) each month for Network Transmission Service pursuant to the applicable Network Integration Service Agreement and annual revenue requirement referred to below. The formula for the annual revenue requirement used to calculate the charges for this service under this 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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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.