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 FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR Part 903) became effective on September 18, 1985 (50 FR 37835).

These charges and rates are established pursuant to section 302(a) of the DOE Organization Act, 42 U.S.C. § 7152(a), through which the power marketing functions of the Secretary of the Interior and Reclamation under the Reclamation Act of 1902, 43 U.S.C. § 371 et seq, as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. § 485h(c), and other acts specifically applicable to the project system involved, were transferred to and vested in the Secretary.

Dated: September 19, 1997.

Elizabeth A. Moler,

Deputy Secretary.

[FR Doc. 97–25749 Filed 9–26–97; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Central Valley Project and California-Oregon Transmission Project—WAPA–77

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–77 and Rate Schedules CV–F9, CV–FT3, CV–NFT3, CV–TPT4, CV–NWT1, CV–PSS1, CV–RFS1, CV–EID1, CV–SPR1, CV–SUR1, COTP–FT1, and COTP–NFT1 placing provisional rates for the Central Valley Project (CVP) commercial firm power and transmission services, power scheduling service, and ancillary services of the Western Area Power Administration (Western), and placing provisional rates for the California-Oregon Transmission Project (COTP) transmission services into effect on an interim basis. The provisional rates, will remain in effect on an interim basis until the Federal Energy Regulatory Commission (FERC) confirms, approves, and places them into effect on a final basis or until they are replaced by other rates. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period.

DATES: The provisional rates will be placed into effect on an interim basis on October 1, 1997, and will be in effect until FERC confirms, approves, and places the provisional rates in effect on a final basis for a 5-year period ending September 30, 2002, or until superseded.

FOR FURTHER INFORMATION CONTACT: Ms. Zola Jackson, Power Marketing Manager, Western Area Power Administration, Sierra Nevada Customer Service Region, 114 Parkshore Drive, Folsom, CA 95630–4710, Telephone (916) 353–4421 or Mr. Joel K. Bladow, Power Marketing Liaison Office, Room 8G–027, 1000 Independence Avenue SW., Washington, DC 20585–0001, Telephone (202) 586–5581.

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy, approved the existing Rate Schedule CV–F8 for CVP commercial firm power on September 19, 1995 (Rate Order No. WAPA–72, 60 FR 52671, October 10, 1995) and FERC confirmed and approved the rate schedule on March 14, 1996, under FERC Docket No. EF95–5012–000 (74 FERC ¶ 62,136). The existing Rate Schedule CV–F8 became effective on October 1, 1995, for the period ending April 30, 1998, and is being superseded by Rate Schedule CV–F9. Under Rate Schedule CV–F8, the composite rate on October 1, 1997, is 26.50 mills per kilowatt-hour (mills/kWh), the base energy rate is 16.93 mills/kWh, the energy tier rate is 26.48 mills/kWh, and the capacity rate is $4.58 per kilowatt-month (kW-month). The provisional rates for CVP commercial firm power in Rate Schedule CV–F9 will result in an overall composite rate of 20.95 mills/kWh on October 1, 1997, and will result in a decrease of approximately 21 percent when compared with the existing CVP commercial firm power rates under Rate Schedule CV–F8.

The Acting Assistant Secretary of Energy, approved the existing Rate Schedules CV–FT2, CV–NFT2, and CV–TPT3 for CVP transmission services, and the existing Rate Schedule CV–PC1 for peaking capacity service on April 12, 1993 (Rate Order No. WAPA–59, 58 FR 35933, July 2, 1993), and FERC confirmed and approved the rate schedules on September 22, 1993, under FERC Docket No. EF93–5011–000 (64 FERC ¶ 61,332). The existing rate schedules became effective on May 1, 1993, for the period ending April 30, 1998. Rate Schedule CV–PC1 is being terminated effective October 1, 1997. Rate Schedules CV–FT2, CV–NFT2, and CV–TPT3 are being superseded by Rate Schedules CV–FT3, CV–NFT3, and CV–TPT4. Under Rate Schedules CV–FT2 and CV–NFT2, the CVP transmission firm and non-firm services rates on October 1, 1997, are $0.43 per kW-month for firm service and 1.23 mills/kWh for non-firm service. On October 1, 1997, the provisional rates in Rate Schedules CV–FT3 and CV–NFT3 will be $0.51 per kW-month for firm CVP transmission service, an 18.6 percent increase when compared with the existing rate, and 1.00 mill/kWh for non-firm CVP transmission service, an 18.7 percent decrease when compared with the existing rate. The provisional rate for transmission of CVP power by others in Rate Schedule CV–TPT4 is a direct pass through cost and will result in no change on October 1, 1997, when compared with the existing rate under Rate Schedule CV–TPT3.

Since the COTP went into operation in 1993, Western has sold COTP transmission services on a short-term basis using rates approved by the Administrator of Western. Rate schedules are being promulgated for COTP firm and non-firm transmission services to be consistent with FERC Order No. 888. The provisional rates for firm transmission service for Western's share of the COTP will result in 9.9 percent (FY 1998) and 34.0 percent (FY 1999 through FY 2002) reductions in the existing rate of $2.03 per kW-month. The provisional rates are $1.83 per kW-month for FY 1998 and $1.34 per kW-month for FY 1999 through FY 2002. The provisional rates for non-firm COTP transmission service will result in 21.2 percent (FY 1998) and 47.8 percent (FY 1999 through FY 2002) reductions in the existing rate of 2.78 mills/kWh. The provisional rates are 2.19 mills/kWh for FY 1998 and 1.45 mills/kWh for FY 1999 through FY 2002.

Power scheduling service, network transmission service, and ancillary services are new services. The provisional rates are designed to recover only the cost incurred for providing the services.

Provisional Rates for CVP Commercial Firm Power

The provisional rates for CVP commercial firm power are designed to recover an annual revenue requirement that includes the investment repayment, interest, purchase power, and operation and maintenance expense. A cost of service study was used to allocate the projected annual revenue requirement for commercial firm power between capacity and energy. Based on this study the capacity revenue requirement includes 100 percent of capacity purchase costs, 50 percent of the CVP investment repayment, interest expense, and power operation and maintenance expense allocated to commercial power, and 100 percent of purchased transmission service expense. These annual costs are reduced by the projected revenue from sales of CVP transmission to determine the capacity revenue requirement. The energy revenue requirement includes 100 percent of energy purchase costs and 50 percent of the CVP investment repayment, interest expense, and power operation and maintenance expense allocated to commercial power. These annual costs are reduced by the projected revenue from sales of surplus power to determine the energy revenue requirement.

The provisional rates will also include an Annual Energy Rate Alignment (AERA). The AERA will be applied to energy purchases from Western under Rate Schedule CV–F9 at or above an average annual load factor of 80 percent, calculated at the end of each fiscal year. The AERA will provide revenues to cover the increased costs of purchased energy. The AERA is the difference between the estimated rate for short-term energy purchases used in the cost of service study for CVP commercial firm power and the provisional CVP energy rate. The AERA is in addition to the provisional CVP energy rate and replaces the existing energy tier rate in Rate Schedule CV–F8.

Adjustment Clauses Associated With the Provisional Rates for CVP Commercial Firm Power

Adjustments for power factors, low voltage losses, and revenue were included in Rate Schedule CV–F8, and will be continued in Rate Schedule CV–F9.

Power Factor Adjustment

The power factor adjustment is included in Rate Schedule CV–F9. The low power factor charge or LPF Charge is a charge that will be applied when the customer does not maintain a calculated 95 percent or greater power factor.

Low Voltage Loss Adjustment

A 1.035 loss adjustment factor will be applied to the billed amounts for low voltage CVP commercial firm power deliveries on the Pacific Gas and Electric system.

Revenue Adjustment

The revenue adjustment clause or RAC, is included in Rate Schedule CV–F9. The RAC, tracks variances in future revenues and expenses, and lessens the probability of significant revenue surplus or deficit to the CVP repayment. The methodology for computing the RAC is a comparison of estimated total revenues less estimated total expenses to actual total revenues less actual total expenses.

Provisional Rates for CVP Transmission Services

The provisional rates in Rate Schedules CV–FT3 and CV–NFT3 for CVP transmission services are based on a revenue requirement that recovers: (1) The CVP transmission system costs for facilities associated with providing all transmission services; and (2) the non-facility costs allocated to transmission services. These provisional firm and non-firm CVP transmission service rates include the costs for scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide the transmission service. The provisional rates are applicable to existing firm and non-firm CVP transmission services and future point-to-point transmission services. The rates charged for firm and non-firm CVP transmission services for a period of one year or less will be no higher than the provisional rates.

Provisional Rate for Transmission of CVP Power by Others

Transmission service costs incurred by Western in the delivery of CVP power over a third party's transmission system to a CVP customer, will be directly passed through to that CVP customer. The provisional rate in Rate Schedule CV–TPT4 is proposed to be automatically adjusted as third party transmission costs are adjusted.

Provisional Rate Formula for Network Transmission Service

Network transmission service, if offered by Western, will be made available consistent with FERC Order No. 888. Due to existing contractual arrangements and not being a control area operator for the CVP, Western may not be able to provide network transmission service but has included a rate formula in case Western offers the service. The provisional rate formula includes the costs for scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide network transmission service.

Provisional Rate for Power Scheduling Service

Power scheduling is a new service being offered by Western that provides for the scheduling of resources to meet loads and reserve requirements. The provisional rate for power scheduling service is designed to recover only the cost incurred for providing the service.

Provisional Rates for Ancillary Services

Western will provide six ancillary services consistent with FERC Order No. 888. Of the six ancillary services offered by Western, two will be provided in conjunction with the sale of CVP and/or COTP transmission services. These are scheduling, system control and dispatch service, and reactive supply and voltage control service. The remaining four ancillary services, regulation and frequency response service, energy imbalance service, spinning reserve service, and supplemental reserve service will be offered subject to availability. The availability and type of ancillary service will be determined based on excess resources available at the time the service is requested, except for the two ancillary services provided in conjunction with the sale of CVP and/or COTP transmission services. The costs associated with scheduling, system control and dispatch service, and for reactive supply and voltage control service are included in the appropriate transmission services rates.

Provisional Rates for COTP Transmission Services

The provisional rates in Rate Schedules COTP–FT1 and COTP–NFT1 for COTP transmission services include a revenue requirement that recovers the costs associated with: (1) Western's participation in the COTP; and (2) scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide the transmission service. The rates are applicable to existing firm and non-firm COTP transmission services and future point-to-point transmission services. The rates charged for firm and non-firm COTP transmission services for a period of one year or less will be no higher than the provisional rates.

The provisional rates for CVP commercial firm power and transmission services, power scheduling service, ancillary services, and for COTP transmission services are developed pursuant to the Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*), through which the power marketing functions of the Secretary of the Interior and the Bureau of

Reclamation under the Reclamation Act of 1902 (43 U.S.C. 371 *et seq.*), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts specifically applicable to the project involved, were transferred to and vested in the Secretary of Energy.

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 of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the FERC. Existing DOE procedures for public participation in power rate adjustments are located at 10 CFR Part 903, effective on September 18, 1985 (50 FR 37835).

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 provisional rates.

Rate Order No. WAPA–77, confirming, approving, and placing the proposed CVP commercial firm power and transmission services rates, power scheduling service, ancillary services, and the COTP transmission services rates into effect on an interim basis, is issued, and the new Rate Schedules CV–F9, CV–FT3, CV–NFT3, CV–TPT4, CV–NWT1, CV–PSS1, CV–RFS1, CV–EID1, CV–SPR1, CV–SUR1, COTP–FT1, and COTP–NFT1 will be submitted promptly to FERC for confirmation and approval on a final basis.

Dated: September 19, 1997.

Elizabeth A. Moler,

Deputy Secretary.

Order Confirming, Approving, and Placing the Central Valley Project; Commercial Firm Power and Transmission Services Rates, Power Scheduling Service and Ancillary Services Rates, and the California-Oregon Transmission Project Transmission Services Rates Into Effect on an Interim Basis

October 1, 1997.

These rates are developed pursuant to the Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (43 U.S.C. 371 *et seq.*), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts specifically applicable to the project involved, were transferred to and vested in the Secretary of the Department of Energy (DOE).

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 the Western Area Power Administration; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Federal Energy Regulatory Commission (FERC). Existing DOE procedures for public participation in power rate adjustments are located at 10 CFR part 903.

Acronyms and Definitions

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

Administrator: The Administrator of Western Area Power Administration.

AERA: Annual energy rate alignment. An energy rate applied at the end of each fiscal year to all energy purchases under Rate Schedule CV–F9 at or above an annual load factor of 80 percent.

Ancillary Services: Those services necessary to support the transfer of electricity while maintaining reliable operation of the transmission system in accordance with good utility practice. Ancillary services are generally described in Federal Energy Regulatory Commission Order No. 888, Docket Nos. RM95–8–000 and RM94–7–001, issued April 24, 1996.

California-Oregon Transmission Project (COTP): The 500-kilovolt transmission project in which Western has part ownership.

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

Capacity Rate: The rate which sets forth the charges for capacity. It is expressed in $ per kW-month and applied to each kW delivered to each customer.

Central Valley Project (CVP): A multipurpose Federal water development project extending from the Cascade Range in northern California to the plains along the Kern River south of the City of Bakersfield.

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

Contract 2947A: Western's contract with Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric Companies for extra high voltage transmission and exchange service; Contract No. 14–06–200–2947A, as amended.

Contract 2948A: Pacific Gas and Electric Company's contract with Western for the sale, interchange and transmission of power; Contract No. 14–06–200–2948A, as amended.

Corps: United States Army Corps of Engineers.

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

Customer: An entity with a contract and receiving service from Western's Sierra Nevada Region.

DOE: United States Department of Energy.

DOE Order RA6120.2: An order dealing with power marketing administration financial reporting and rate making procedure.

EA2: Energy Bank Account No. 2 between Western and PG&E under Contract 2948A.

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

Energy Rate: The rate which sets forth the charges for energy. It is expressed in mills/kWh and applied to each kWh delivered to each customer.

Energy Tier Rate: Existing energy rate in Rate Schedule CV–F8 applied to energy sales at a 70 percent and higher monthly load factor.

FERC: Federal Energy Regulatory Commission.

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

First Preference Customer: An entity qualified to use preference power within a county of origin (Trinity, Calaveras and Tuolumne) as specified under the Trinity River Division Act of August 12, 1955 (69 Stat. 719), and the Flood Control Act of 1962 (76 Stat. 1180).

FY: Fiscal year; October 1 to September 30.

Interior: United States Department of the Interior.

Intertie: Pacific Northwest-Pacific Southwest Intertie.

kV: Kilovolt—the electrical unit of measure of electric potential that equal one thousand volts.
kvar: Kilovolt-ampere reactive—the electrical unit of measurement for reactive power in a circuit that equals one thousand volt-amperes.
kW: Kilowatt—the electrical unit of capacity that equal one thousand watts.
kW-month: The electrical unit of the monthly amount of capacity.
kWh: Kilowatt-hour—the electrical unit of energy that equals one thousand watts in one hour.
Load Factor: The ratio of average load in kW supplied during a designated period to the peak or maximum load in kW occurring in that period.
LPF Charge: Low power factor charge.
Mill: A monetary denomination of the United States that equal one tenth of a cent or one thousandth of a dollar.
Mills/kWh: Mills per kilowatt-hour—the unit of charge for energy.
MW: Megawatt—the electrical unit of capacity that equal one million watts or one thousand kilowatts.
NEPA: National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*).
Net Revenue: Revenue remaining after paying all annual expenses.
Non-Firm: A type of product and/or service that is not always available at the time requested by the customer.
Northwest: Northwest United States.
O&M: Operation and maintenance.
PG&E: Pacific Gas and Electric Company.
Power: Capacity and energy.
Power Factor: The ratio of real to apparent power at any given point and time in an electrical circuit. Generally it is expressed as a percentage ratio.
Power Scheduling Service: A service that provides for the scheduling of resources to meet loads and reserve requirements.
Preference: The requirements of Reclamation law which provide that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936 (Reclamation Project Act of 1939, section 9(c), 43 U.S.C. 485h(c)).
Project Use: Power as defined by Reclamation law and/or used to operate CVP facilities.
Provisional Rates: Rates which have been confirmed, approved, and placed in effect on an interim basis by the Deputy Secretary of the Department of Energy.
PRS: Power repayment study.
RAC: Revenue Adjustment Clause.
Rate Brochure: A document prepared for public distribution explaining the rationale and background of the rate proposal contained in this rate order dated March 25, 1996.
Reclamation: United States Department of the Interior, Bureau of Reclamation.
Reclamation Law: A series of Federal laws. Viewed as a whole, these laws create the originating framework in which the Western Area Power Administration markets power.
Revenue Requirement: The revenue required to recover O&M expenses, purchase power and transmission service expenses, interest, deferred expenses, and repayment of Federal investments, or other assigned costs.
Sierra Nevada Region: The Sierra Nevada Customer Service Region of Western Area Power Administration.
Secretary: Secretary of Energy.
Western: United States Department of Energy, Western Area Power Administration.
Withdrawable: Power that may be withdrawn under certain conditions.

Effective Date

The new rates will become effective on an interim basis on the first day of the first full billing period beginning on or after October 1, 1997, and will be in effect pending FERC's approval of them or substitute rates on a final basis for a 5-year period ending September 30, 2002, or until superseded.

Public Notice and Comment

The Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR part 903, have been followed by Western in the development of these rates. The following summarizes the steps Western took to ensure involvement of interested parties in the rate process:

1. The proposed rate adjustment was initiated on May 1, 1996, when a letter announcing the first of four informal customer workshops was mailed to all CVP customers. The first workshop was held on May 13, 1996, in Folsom, California. Sequential workshops were held on August 21, October 25, and December 17, 1996, in Folsom, California. At these informal workshops, Western explained the rationale for the rate adjustment, presented rate designs and methodologies, and answered questions.

2. A **Federal Register** notice was published on March 4, 1997 (62 FR 9763), officially announcing the proposed rates for the CVP and COTP, initiating the public consultation and comment period, and announcing the public information and public comment forums.

3. On March 7, 1997, letters were mailed from Western's Sierra Nevada Regional Office to all CVP preference customers and interested parties transmitting the **Federal Register** notice of March 4, 1997, and announced the times and locations for the two public forums.

4. On March 25, 1997, beginning at 9 a.m. PST, the public information forum was held at Western's Sierra Nevada Regional Office in Folsom, California. At the public information forum Western provided detailed explanations of the proposed rates for the CVP and COTP, provided a list of issues that could change the proposed rates, and answered questions. Notice was given that additional information would be provided at the public comment forum. A rate brochure and an information handout were provided at the forum.

5. On April 24, 1997, beginning at 9 a.m. PDT, the public comment forum was held at Western's Sierra Nevada Regional Office in Folsom, California. At the start of the forum, Western presented the updated rates for the CVP and COTP, provided a detailed explanation of the changes to the proposed rates, and answered questions. A handout containing information regarding the updated rates was provided. After providing this information, Western gave the public an opportunity to comment for the record. Three representatives made oral comments.

6. Twelve comment letters were received during the consultation and comment period. The consultation and comment period ended June 2, 1997. All formally submitted comments have been considered in the preparation of this rate order.

Project History

The CVP is a large water and power system, initially authorized by Congress in 1935, which covers approximately one-third of the State of California. Legislatively defined purposes set the priorities for the CVP as: (1) River regulation; (2) improvement of navigation; (3) flood control; (4) irrigation; (5) domestic uses; and (6) power. In addition, the CVP Improvement Act of 1992 added fish and wildlife habitat as a priority to the list of CVP purposes.

The CVP is located within the Central Valley and Trinity River basins of California. The CVP includes 18 dams and reservoirs with a total storage capacity of 13 million acre-feet. The system includes 615 miles of canals, 5 pumping facilities, 11 powerplants with a maximum operating capability of about 2,044 MW, approximately 948 circuit-miles of high voltage transmission lines, 15 substations, and 23 communication sites. Reclamation operates the water control and delivery system and all of the powerplants with the exception of the San Luis Unit, which is operated by the State of California for Reclamation.

The Emergency Relief Appropriations Act of 1935 initially authorized the CVP to be constructed by Reclamation to include Shasta Dam on the Sacramento River in the north and Friant Dam on the San Joaquin River in the south. Located between these are the Tracy Pumping Plant; the Delta-Mendota, Contra Costa, Friant-Kern, and Madera canals; and the Delta Cross Channel. Powerplants at Shasta and Keswick dams were also included in the initial authorization, along with high voltage transmission lines designed to transmit power from Shasta and Keswick powerplants to the Tracy pumps, and to integrate the Federal hydropower into other electric systems.

In 1944, Congress authorized the American River Division, to be constructed by the Corps. This Division included Folsom Dam and Powerplant, Nimbus Dam and Powerplant, and the Sly Park Unit, all located on the American River. In 1949, the Division was reauthorized for integration into the CVP.

The Trinity River Division was authorized by Congress in 1955 to include Trinity Dam and Powerplant, Lewiston Dam and Powerplant, and the Lewiston Fish Facilities, all located on the Trinity River. The Trinity Division also includes Judge Francis Carr Powerplant, Whiskeytown Dam, and the Spring Creek Powerplant.

The San Luis Unit, including the B.F. Sisk San Luis Dam and San Luis Reservoir, San Luis Canal, Coalinga Canal, O'Neill and Dos Amigos pumping plants, and William R. Gianelli Pump-Generator, was authorized by Congress in 1960.

In 1965, Congress authorized construction of the Auburn-Folsom South Unit as an addition to the CVP. This unit included four subunits, three of which have been constructed; the Foresthill, Folsom-Malby, and Folsom South Canal subunits. Funding to complete the construction of the Auburn Dam, Reservoir and Powerplant, which is part of the fourth subunit, has not been authorized by Congress.

Congress authorized the San Felipe Division in 1967, and the Allen Camp Unit in 1976.

Three Corps projects, Buchannan, Hidden, and New Melones, were authorized for integration into the CVP in 1962. Black Butte, another Corps project completed in the 1960's, was added to the CVP in 1970 by the Black Butte Integration Act.

In 1964, Congress authorized the 500-kV Intertie, of which Western has a 400 MW entitlement of transmission capacity. On July 31, 1967, Western, PG&E, Southern California Edison Company, and San Diego Gas & Electric Company entered into Contract 2947A, as amended, to coordinate the operation of the Intertie for the purpose of transmitting electric power between the Northwest and the Pacific Southwest.

Western, in marketing the Federal hydroelectric power generated from the CVP, currently has 80 CVP preference and 34 CVP project use customers, serving an estimated two million people.

In 1967, PG&E and Western executed Contract 2948A. This contract provides for the sale, interchange, and transmission of electric capacity and energy between Western and PG&E. Contract 2948A also includes provisions for the integration of power generated from the CVP with the 400 MW of entitlement on the Intertie. The contract also provides that PG&E will support a maximum simultaneous demand of 1,152 MW for the preference customers through 2004. If CVP power cannot meet obligations to the preference customers, Contract 2948A provides Western with the right to purchase capacity and energy from PG&E to meet those requirements. Any energy in excess of Western's obligations to preference customers can be sold to PG&E through a banking provision in the contract. The energy made available under this banking arrangement allows Western to supplement CVP generation to meet preference customer load.

Power generated from the CVP is first dedicated to project use. The remaining power is allocated to various preference customers in California. Preference customers consist of: (1) Irrigation and water districts; (2) public utility districts; (3) municipalities; (4) Federal agencies; (5) State agencies; (6) rural electric cooperatives; (7) local and suburban passenger transportation entities; and (8) joint power authorities.

Each preference customer's CRD is composed of firm long-term power allocations, and may include withdrawable allocations that are currently allocated, but unused by another customer. For this rate adjustment it is assumed that all customer withdrawable CRDs can be withdrawn in the event the load level of 1,152 MW set forth in Contract 2948A is exceeded.

Western's preference customer load level is limited under Contract 2948A to a maximum simultaneous demand, excluding project loads, of 1,152 MW. The maximum simultaneous demand is the sum of each preference customer's demand for CVP power at a coincidental moment, adjusted to the load center at the Tracy Switchyard. Notwithstanding the simultaneous demand limit, Western has contractual obligations to serve approximately 1,470 MW of firm CRD to its preference customers. This level of CRD can be served because of the diversity in customers' loads.

The COTP is a 342-miles long 500-kV transmission project that electrically interconnects the Northwest to California with what is called the Third AC Intertie. Operational since March 1993, the COTP interconnects with the transmission systems of the Northwest at the Captain Jack Substation, and with the Pacific Southwest by its connection near the Tesla Substation to the existing Intertie. The project owners include Western as well as several non-Federal participants.

Power Repayment Study

Power repayment studies are prepared each fiscal year to determine if power revenues will be sufficient to pay, within the prescribed time periods, all costs assigned to the CVP power function. Repayment criteria are based on law, policies, and authorizing legislation. DOE Order RA6120.2, section 12b, requires that:

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

CVP Transmission Service Rate Study

Transmission service rates are charged to CVP customers receiving transmission services over the CVP system for the transmission of non-CVP power. A transmission service rate study was prepared to ensure that transmission service rates are based on the cost of service of the CVP transmission system.

A review of the CVP transmission service rate study indicated that the existing firm and non-firm CVP transmission service rates under Rate Schedules CV–FT2 and CV–NFT2, needed to be adjusted. The provisional rate for firm CVP transmission service is $0.51 per kW-month, an 18.6 percent increase from the existing rate of $0.43 per kW-month. The provisional rate for non-firm CVP transmission service is 1.00 mill/kWh, an 18.7 percent reduction in the existing 1.23 mills/kWh rate. The change in the firm CVP transmission service rate is due to increases in transmission facilities costs and in the basis for assigning miscellaneous and non-facility investment and O&M costs to transmission to better reflect costs associated with transmission for all users. The change in the non-firm CVP transmission service rate is primarily due to a change in the load factor used in determining the denominator in the rate calculation. The same revenue requirement is used in determining the firm and non-firm CVP transmission service rates.

Existing and Provisional Rates

CVP Commercial Firm Power

The provisional rates for CVP commercial firm power are designed to recover an annual revenue requirement that includes the investment repayment, interest, purchase power, and O&M expenses. The provisional rates will also include an AERA. The AERA will be applied to energy purchases from Western under Rate Schedule CV–F9 at or above an average annual load factor of 80 percent, calculated at the end of each fiscal year. The AERA will provide revenues to cover the increased costs of purchased energy. The AERA is in addition to the provisional CVP energy rate and replaces the existing energy tier rate.

A comparison of the existing and provisional rates for CVP commercial firm power follows:

COMPARISON OF EXISTING AND PROVISIONAL RATES

CVP Commercial firm power rate schedule			
Effective period	Existing (effective 10/01/97 to 04/30/98)	Provisional	Percent change from existing rate
Composite Rate (mills/kWh):			
10/01/97 to 04/30/98	26.50	20.95	(21)
05/1/98 to 09/30/98	....	20.95	(21)
10/01/98 to 09/30/99	....	19.31	(27)
10/01/99 to 09/30/00	....	19.31	(27)
10/01/00 to 09/30/01	....	18.56	(30)
10/01/01 to 09/30/02	....	20.08	(24)
Capacity Rate ($ per kW-month):			
10/01/97 to 04/30/98	4.58	5.03	10
5/1/98 to 09/30/98	....	5.03	10
10/01/98 to 09/30/99	....	4.37	(5)
10/01/99 to 09/30/00	....	4.31	(6)
10/01/00 to 09/30/01	....	3.81	(17)
10/01/01 to 09/30/02	....	4.02	(12)
Energy Rate (mills/kWh):			
10/01/97 to 04/30/98	16.93	10.31	(39)
05/1/98 to 09/30/98	....	10.31	(39)
10/01/98 to 09/30/99	....	10.06	(41)
10/01/99 to 09/30/00	....	10.19	(40)
10/01/00 to 09/30/01	....	10.51	(38)
10/01/01 to 09/30/02	....	11.58	(32)
AERA Rate (mills/kWh) supersedes existing energy tier rate in Rate Schedule CV–F8.[1]			
10/01/97 to 04/30/98	([2])	2.86	....
05/1/98 to 09/30/98	([2])	2.86	....
10/01/98 to 09/30/99	([2])	3.57	....
10/01/99 to 09/30/00	([2])	3.92	....
10/01/00 to 09/30/01	([2])	4.09	....
10/01/01 to 09/30/02	([2])	3.53	....

[1] The existing energy tier rate under Rate Schedule CV–F8 is 26.48 mills/kWh and is effective for the period October 1, 1997, to April 30, 1998.

[2] None.

CVP Transmission Services and Transmission of CVP Power by Others

A comparison of the existing and provisional rates for CVP transmission services and for transmission of CVP power by others follows:

COMPARISON OF EXISTING AND PROVISIONAL RATES

CVP Transmission rate schedules			
Effective period	Existing (effective 10/01/97 to 04/30/98)	Provisional	Percent change from existing rate
Firm Transmission Rate ($ per kW-month);			
10/01/97 to 04/30/98	0.43	0.51	18.6
05/1/98 to 09/30/02	....	0.51	18.6
Non-Firm Transmission Rate (mills/kWh):			
10/01/97 to 04/30/98	1.23	1.00	(18.7)
05/1/98 to 09/30/02	....	1.00	(18.7)
Transmission of CVP Power by Others Rate Schedule:			
10/01/97 to 04/30/98	[1]	[1]	[2]
05/1/98 to 09/30/02	[1]	[1]	[2]

[1] Pass through cost.
[2] Not applicable.

Network Transmission Service

The provisional rate formula for network transmission service, if offered by Western, is the product of the network customer's load ratio share times one twelfth (1⁄12) of the annual network transmission revenue requirement. The load ratio share is based on the network customer's hourly load, including its designated network load not physically interconnected with the CVP transmission system, coincident with Western's monthly CVP transmission system peak minus coincident peak usage of all firm CVP (including reserved capacity) point-to-point transmission service. The provisional network transmission service rate formula includes the cost for scheduling, system control and dispatch service, and reactive supply and voltage control services associated with the transmission service. The provisional rate is effective for the period beginning October 1, 1997, through September 30, 2002.

Power Scheduling Service

Power scheduling service is a new service being offered by Western that provides for the scheduling of resources to meet load and reserve requirements. The provisional rate for power scheduling service is $75.80 per hour and will be applied based on an estimated time to provide the service to each customer receiving the service. The provisional rate is effective for the period beginning October 1, 1997, through September 30, 2002.

Ancillary Services

Of the six ancillary services offered by Western, two will be provided in conjunction with the sale of CVP and/or COTP transmission services. These are scheduling, system control and dispatch service, and reactive supply and voltage control service. The remaining four ancillary services, regulation and frequency response service, energy imbalance service, spinning reserve service, and supplemental reserve service will be offered subject to availability. The availability and type of ancillary service will be determined based on excess resources available at the time the service is requested, except for the two ancillary services provided in conjunction with the sale of CVP and/or COTP transmission services. The provisional rates and descriptions for the six ancillary services are as follow:

PROVISIONAL RATES

Ancillary services rate schedules	
Ancillary service type	Rate
Scheduling, System Control and Dispatch Service—is required to schedule the movement of power through, out of, within, or into a control area.	Included in appropriate transmission rates.
Reactive Supply and Voltage Control Service—is reactive power support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.	Included in appropriate transmission rates.
Regulation and Frequency Response Service—providing generation to match resources and loads on a real-time continuous basis. Rate will be applied to resources reserved for this service.	Monthly: $1.48 per kW-month; Weekly: $0.3360 per kW-week; Daily: $0.0480 per kW-day.
Energy Imbalance Service—is provided when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month. Hourly deviation (MW) is the net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.	*Within Limits of Deviation Band:* Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP commercial firm power, then in effect. *Outside Limits of Deviation Band:* (i) Positive Deviations—no charge, lost to the system. (ii) Negative Deviations—during on-peak hours, the greater of 3 times the composite.
Rate for CVP commercial firm power, then in	Effect, or any additional cost incurred. During off-peak hours, the greater of the composite rate for CVP commercial firm power, then in effect, or any additional cost incurred.

PROVISIONAL RATES—Continued

Ancillary services rate schedules	
Ancillary service type	Rate
Spinning Reserve Service—is providing capacity that is available the first ten minutes to take load and is synchronized with the power system. Rate will be applied to resources reserved for this service.	Monthly: $1.35 per kW-month; Weekly: $0.3024 per kW-week; Daily: $0.0432 per kW-day; Hourly: $0.0018 per kWh.
Supplemental Reserve Service—is providing capacity that is not synchronized, but can be available to serve loads within ten minutes. Rate will be applied to resources reserved for this service.	Monthly: $1.27 per kW-month; Weekly: $0.2856 per kW-week; Daily: $0.0408 per kW-day; Hourly: $0.0017 per kWh.

Provisional Rates for COTP Transmission Services

A comparison of the existing and provisional rates for transmission services for Western's share of the COTP follows:

COMPARISON OF EXISTING AND PROVISIONAL RATES

COTP Transmission rate schedules			
Effective Period	Existing	Provisional	Percent change
Firm Transmission Rate ($ per kW-month):			
10/01/97 to 09/30/98	2.03	1.83	(9.9)
10/01/98 to 09/30/02	2.03	1.34	(34.0)
Non-Firm Transmission Rate (mills/kWh):			
10/01/97 to 09/30/98	2.78	2.19	(21.2)
10/01/98 to 09/30/02	2.78	1.45	(47.8)

Certification of Rate

Western's Administrator has certified that the CVP commercial firm power, CVP transmission services, transmission of CVP power by others, network transmission service, power scheduling service, and ancillary services rates, and COTP transmission services rates placed into effect on an interim basis herein are the lowest possible rates consistent with sound business principles. The provisional rates have been developed in accordance with administrative policies and applicable laws.

Discussion

CVP Commercial Firm Power

According to Reclamation law, Western must establish power rates sufficient to recover operation, maintenance, and purchased power expenses, and repay the Federal government's investment in generation and transmission facilities. Rates must also be set to cover interest expenses on the unpaid balance of facilities' investments, replacements and additions, and certain non-power costs in excess of the irrigation users' ability to repay.

The existing CVP commercial firm power rates were confirmed and approved by FERC for the period October 1, 1995 through April 30, 1998, in a FERC Order issued March 14, 1996. Under Rate Schedule CV–F8 for the FY 1998, the composite rate on October 1, 1997, is 26.50 mills/kWh, the base energy rate is 16.93 mills/kWh, the energy tier rate is 26.48 mills/kWh, and the capacity rate is $4.58 per kW-month. The provisional rates for CVP commercial firm power will result in an overall composite rate decrease of approximately 21 percent on October 1, 1997, when compared to the existing FY 1998 CVP commercial firm power rates in Rate Schedule CV–F8. On a composite rate basis, the proposed rates continue to decrease in four years of the 5-year period ending September 30, 2002. The renegotiation and termination of several long term firm purchase power contracts are the major factors contributing to this decrease.

The provisional rates consist of a capacity rate, an energy rate, and an annual energy rate alignment. The AERA will be an additional cost for energy purchases from Western under Rate Schedule CV–F9 at or above an average annual load factor of 80 percent, calculated at the end of each fiscal year. The AERA will provide revenues to cover the increased costs of purchased energy needed to meet the higher levels of sales. The AERA is the difference between the estimated rate for short-term energy purchases used in the cost of service study for CVP commercial firm power and the provisional CVP energy rate, as shown below.

Fiscal year	Estimated purchase rate (mills/kWh)	CVP commercial firm energy rate (mills/kWh)	AERA (mills/kWh)
1998	13.17	10.31	2.86
1999	13.63	10.06	3.57
2000	14.11	10.19	3.92
2001	14.60	10.51	4.09
2002	15.11	11.58	3.53

The AERA provides risk mitigation for the assumptions used in the cost of service study for CVP commercial firm power. If the estimated purchase costs are too low and customers increase their energy purchases from Western, then the AERA will provide additional revenues to cover the increased costs of energy. The AERA applies to only those customers who purchase energy from Western under Rate Schedule CV–F9 at or above an average annual load factor of 80 percent. The AERA is in addition to the provisional CVP energy rate and replaces the existing energy tier rate in Rate Schedule CV–F8. The billing for the AERA will be based on the customer's average annual load factor and will occur at the end of each fiscal year, based on the following formula:

AERA=(Total kWh − (ALF * Hours in fiscal year * 0.7999)) * AERA rate

Where:

AERA=Annual Energy Rate Alignment
kWh=Energy purchased from Western during a fiscal year.

ALF=Average of monthly billed capacity purchased from Western during a fiscal year.

An example of AERA billing follows:

Example of AERA Billing for FY 1998

Assumption: Average of monthly billed capacity purchased from Western during the FY 1998 is 50 MW and the total annual energy purchased from Western is 394,200,000 kWh.

Calculation of energy below 80 percent load factor:

50,000 kW × 8,760 hours × 0.7999=350,356,200 kWh

Energy at or above 80 percent load factor billed at AERA rate:

394,200,000 kWh − 350,356,200 kWh=43,843,800 kWh

43,843,800 kWh × 2.86 mills/kWh0=$125,393.27

In order to utilize the CVP power resources to their maximum benefit, Western supports CVP generation with capacity and energy purchases, mainly from Northwest resources and PG&E. The cost of the CVP power generation is split equally between the capacity and energy revenue requirements. The amount of capacity and energy available from the CVP hydroelectric system varies widely because of hydrologic conditions. These conditions can also impact the value of the capacity and energy. Due to this variability, an equal split between the capacity and energy revenue requirements for recovery of the cost of the CVP power generation is reflective of its actual costs associated with providing power to all CVP customers.

Currently, the existing rates under Rate Schedule CV–F8 reflect a split of 35 percent capacity and 65 percent energy. The provisional rates for CVP commercial firm power are based on the total annual CVP revenue requirement being allocated between capacity and energy in the following manner:

1. The capacity revenue requirement includes 100 percent of capacity purchase costs, 100 percent of purchased transmission service expense, and 50 percent of the annual CVP investment repayment, interest expense, and power O&M expense allocated to commercial power. These annual costs are reduced by the projected revenue from CVP transmission sales to determine the capacity revenue requirement.

2. The energy revenue requirement includes 100 percent of energy purchase costs and 50 percent of the annual CVP investment repayment, interest expense, and power O&M expense allocated to commercial power. These annual costs are reduced by the projected revenue from surplus power sales to determine the energy revenue requirement.

The resulting percentage splits between the capacity and energy revenue requirements for the provisional rates varies from 51 percent allocated to capacity in FY 1998 to 42 percent allocated to capacity in FY 2002 due to changes in costs and revenues each year. The average split for the 5-year period is 46 percent to capacity and 54 percent to energy. The annual percentage splits between the capacity and energy revenue requirements are as follow:

Effective period	Capacity (percent)	Energy (percent)
10/1/97—9/30/98	51	49
10/1/98—9/30/99	48	52
10/1/99—9/30/00	47	53
10/1/00—9/30/01	43	57
10/1/01—9/30/02	42	58
5-year average	46	54

Power Factor Adjustment

The power factor adjustment under existing Rate Schedule CV–F8 will continue and is included with the provisional rates for CVP commercial firm power. The low power factor charge or LPF Charge, will continue to encourage preference customers to monitor their power factors and maintain them at 95 percent or greater. Western will continue the existing LPF Charge under Rate Schedule CV–F9, which includes a rate of $2.50 per kvar for additional kvar required to raise the customer's power factor to 95 percent. The $2.50 per kvar rate represents the estimated cost of Western purchasing and installing equipment to increase a customer's power factor plus an additional charge to encourage customers to monitor poor power factors. The LPF Charge will be applied when the customer does not maintain a calculated 95 percent or greater power factor.

The customer's calculated power factor used to determine if a charge will be assessed is the arithmetic mean of the customer's measured monthly average power factor and the measured monthly on-peak power factor, rounded to the nearest whole percent with 0.5 percent or greater rounded to the next higher percent. The measured on-peak power factor is equal to the power factor measured during a customer's maximum peak demand for each month, as recorded at the customer's point of delivery. In the event of multiple occurrences of the same peak demand, the lowest associated power factor will be used. The measured average power factor will be the average power factor for the billing month. Those customers with multiple meter points will be charged for the ''totalizer'' of the multiple meter points. The monthly on-peak and average power factors are those recorded for CVP power only.

Low Voltage Loss Adjustment

The low voltage adjustment under existing Rate Schedule CV–F8 will continue and is included in the provisional rates for CVP commercial firm power. A 1.035 loss adjustment factor will be applied to the billed amounts for low voltage CVP power deliveries on PG&E's system under Contract 2948A.

Revenue Adjustment

The revenue adjustment clause or RAC, tracks variances in future revenues and expenses, and lessens the probability of significant revenue surplus or deficit to the CVP repayment. The methodology for computing the RAC is a comparison of estimated total revenues less estimated total expenses to actual total revenues less actual total expenses. If the actual net revenue is more than the estimated net revenue, CVP preference customers receive a credit. If actual net revenue is less than the estimated net revenue, CVP preference customers may have a surcharge, if needed to make a minimum investment payment. The limit for surcharges is $20 million. The limit for credits is $20 million plus the amount of EA2 credit or other purchase power contract adjustments used during the fiscal year for which the RAC is being calculated. The RAC is a carryover from Rate Schedule CV–F8.

CVP Transmission Services and Transmission of CVP Power by Others

The provisional rate for firm CVP transmission service is $0.51 per kW-month, an 18.6 percent increase from the existing rate of $0.43 per kW-month under Rate Schedule CV–FT2. The provisional rate for non-firm CVP transmission service is 1.00 mill/kWh, an 18.7 percent reduction in the existing 1.23 mills/kWh rate under Rate Schedule CV–NFT2. The change in the firm CVP transmission service rate is due to increases in transmission facilities costs and in the basis for assigning miscellaneous and non-facility O&M costs to transmission to better reflect costs associated with transmission for all users. The change in the non-firm CVP transmission service rate is primarily due to a change in the load factor used in determining the denominator in the rate calculation. The same revenue requirement is used in determining the firm and non-firm CVP transmission service rates.

The provisional rates for CVP transmission services are based on a revenue requirement that recovers: (1) The CVP transmission system costs for facilities associated with providing all transmission services; and (2) the non-facility costs allocated to transmission service. These provisional firm and non-firm CVP transmission service rates include the costs for scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide the transmission service. If scheduling, system control and dispatch service, and reactive supply and voltage control service are not provided by Western, the customers will be given credit for the cost associated with these services, as agreed by the parties. The provisional rates are applicable to existing firm and non-firm CVP transmission services and future point-to-point transmission services. The rates charged for firm and non-firm CVP transmission services for a period of one year or less will be no higher than the provisional rates.

Transmission service costs incurred by Western in the delivery of CVP power over a third party's transmission system to a CVP customer, will be directly passed through to that CVP customer. Both annual revenues and expenses are included in the PRS to account for all charges, even though the net effect is zero. Transmission pass through revenues and expenses are estimated using existing customer load forecasts and project use requirements, and applicable transmission service rates. Transmission pass through revenues and expenses primarily consist of payments to PG&E for transmission services to preference and project use loads, and payments to the Sacramento Municipal Utility District for transmission services to preference customers.

Network Transmission Service

Network transmission service is a new service and, if offered by Western, will be made available consistent with FERC Order No. 888. Due to existing contractual arrangements and not being a control area operator for the CVP, Western may not be able to provide network transmission service but has included a rate formula in case Western offers the service. The provisional rate formula for network transmission service is based on a revenue requirement that recovers the CVP transmission system costs for facilities associated with providing all transmission services and the non-facility costs allocated to transmission service. The provisional rate formula includes the costs for scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide the network transmission service.

Power Scheduling Service

Power scheduling is a new service being offered by Western that provides for the scheduling of resources to meet loads and reserve requirements. The provisional rate for power scheduling service is designed to recover only the cost incurred by Western for providing the service. The provisional rate includes two cost components. The first cost component is the FY 1997 hourly cost for dispatcher and/or scheduler resources, escalated for the rate adjustment period of FY 1998 through FY 2002 to obtain an average hourly cost. The second cost component is an estimated hourly cost for equipment necessary in providing the service.

Ancillary Services

Ancillary services are new services and, if offered by Western, will be made available consistent with FERC Order No. 888. Of the six ancillary services offered by Western, two will be provided in conjunction with the sale of CVP and/or COTP transmission services. These are scheduling, system control and dispatch service, and reactive supply and voltage control service. The remaining four ancillary services, regulation and frequency response service, energy imbalance service, spinning reserve service, and supplemental reserve service will be offered subject to availability. Western's sales of ancillary services are subject to the availability of its power resources because Western allocates most of its power resources to preference entities under long-term commitments. The availability and type of ancillary service will be determined based on excess resources available at the time the service is requested.

The provisional rates for ancillary services are designed to recover only the costs associated with providing the service(s). The costs for providing scheduling, system control and dispatch service, and reactive supply and voltage control service are included in the provisional transmission services rates. The provisional rate for energy imbalance service is based on standards and practices used in the electric utility industry. For the provisional rates for regulation and frequency response, spinning reserve, and supplemental reserve services, Western used a detailed cost of service study to determine these rates, which are based on CVP facilities that are used in providing the service(s). Only those CVP facilities costs are considered in the determination of rates for regulation and frequency response, spinning reserve, and supplemental reserve services. The CVP facilities that are used in providing regulation and frequency response, spinning reserve, and supplemental reserve services are the Shasta, Folsom, Trinity, New Melones, Spring Creek, and Judge F. Carr powerplants. The Nimbus and Keswick powerplants are not available because of river run conditions. There are no governors at the O'Neill and San Luis powerplants, which makes them unavailable for providing the services.

COTP Transmission Services

Since the COTP went into operation in 1993, Western has sold COTP transmission services on a short-term basis using rates approved by the Administrator. Rate schedules are being promulgated for COTP firm and non-firm transmission services to be consistent with FERC Order No. 888. The provisional rates for firm transmission service for Western's share of the COTP are $1.83 per kW-month for FY 1998 and $1.34 per kW-month for FY 1999 through FY 2002. These rates for firm COTP transmission service result in 9.9 percent (FY 1998) and 34.0 percent (FY 1999 through FY 2002) reductions in the existing rate of $2.03 per kW-month. The provisional rates for non-firm COTP transmission service are 2.19 mills/kWh for FY 1998 and 1.45 mills/kWh for FY 1999 through FY 2002. These rates for non-firm COTP transmission service result in 21.2 percent (FY 1998) and 47.8 percent (FY 1999 through FY 2002) reductions in the existing rate of 2.78 mills/kWh. These rates are lower than the existing rates for COTP firm and non-firm transmission services due to reduced costs for and the terminations of some contracts for COTP transmission capacity.

The provisional rates for COTP transmission services includes a revenue requirement that recovers the costs associated with: (1) Western's participation in the COTP; and (2) scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide the transmission service. If scheduling, system control and dispatch service, and reactive supply and voltage control service are not provided by Western, the customers will be given credit for the cost associated with these services, as agreed by the parties. The provisional rates are applicable to existing firm and non-firm COTP transmission services and future point-to-point transmission services. The rates charged for firm and non-firm COTP transmission services for a period of one year or less will be no higher than the provisional rates.

Statement of Revenue and Related Expenses

The following table provides a summary of revenues and expenses for the 5-year provisional rate period and the 3-year existing rate period.

CVP COST EVALUATION RATE PERIOD REVENUES AND EXPENSES ($1,000)

	Provisional rate PRS FY 1998–02	Existing rate PRS FY 1996–98	Difference
Total Revenues	824,651	609,954	Not Applicable See Note below.
Revenue Distribution:			
O&M	216,776	105,521	Note: The revenues and expenses for the provisional rates are for 5 years. Those for the existing rates are for 3 years. Therefore, the difference is not applicable.
Purchase Power	390,689	407,804	
Transmission	80,335	45,098	
Interest	54,536	29,933	
Other	9,073	0	
Investment Repayment	73,242	21,598	
Capitalized Expenses	0	0	
Prior-Year Adjustment	0	0	

The following table provides a summary of the average annual revenues and expenses for the provisional and existing rate periods.

CVP COMPARISON OF COST EVALUATION RATE PERIOD AVERAGE ANNUAL REVENUES AND EXPENSES ($1,000)

	Provisional rate average annual	Existing rate average annual	Difference
Total Revenues	164,930	203,318	(38,388)
Revenue Distribution:			
O&M	43,355	35,174	8,181
Purchase Power	78,138	135,935	(57,797)
Transmission	16,067	15,033	(1,034)
Interest	10,907	9,978	(929)
Other	1,815	0	1,815
Investment Repayment	14,648	7,199	7,449
Capitalized Expenses	0	0	....
Prior-Year Adjustment	0	0	....

Basis for Rate Development

The existing rates for CVP commercial firm power, CVP transmission services and transmission of CVP power by others in Rate Schedules CV–F8, CV–FT2, CV–NFT2, and CV–TPT3 expire April 30, 1998. Reduced costs for and the terminations of some of Western's power purchase and COTP transmission contracts have occurred. Power scheduling, network transmission, and ancillary services are new services being offered by Western. The proposed rate adjustment is needed to put into place rates, which will replace the existing rates, that reflect reduced purchase power expenses due to a decrease in customers' CVP power purchases, reduced costs of transmission contracts, current methodology in rate design, and to provide rates for new services. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period. The provisional rates are scheduled to go in effect on October 1, 1997, to correspond with the start of the Federal fiscal year, and will remain in effect through September 30, 2002.

The provisions for power factor adjustment, low voltage loss adjustment, and revenue adjustment are part of the provisional rates for CVP commercial firm power. The provisions and methodologies for these adjustments are not being modified and will remain as specified in Rate Schedule CV–F8.

Comments

During the public consultation and comment period, Western received 12 written comments on the rate adjustment. In addition, three customer representatives commented during the April 24, 1997 public comment forum. All comments received by the end of the public consultation and comment period, June 2, 1997, were reviewed and considered in the preparation of this rate order.

Written comments were received from the following sources:

Bookman-Edmonston Engineering, Inc. (California)
Calaveras Public Power Agency (California)
National Aeronautics and Space Administration, Ames Research Center (California)
Northern California Power Agency (California)
City of Palo Alto (California)
City of Redding (California)
City of Roseville (California)
Sacramento Municipal Utility District (California)
City of Santa Clara (California)
Trinity County Board of Supervisors (California)
Trinity County Public Utilities District (California)

Tuolumne Public Power Agency (California)

The comments received in correspondence dealt with the CVP commercial firm power rate design, specifically, the capacity and energy split for revenue recovery and the AERA, the CVP transmission service rate design, separate county-of-origin rate, and the RAC. All comments supported Western's efforts to reduce the rates. The following is a summary of the comments received by the end of the consultation and comment period and Western's responses to those comments. The comments and responses, paraphrased for brevity are presented below. Specific comments are used for clarification where necessary.

CVP Commercial Firm Power (Capacity and Energy Revenue Requirement Split)

The following comments relate to the change in CVP rate design from recovering 35 percent of the revenue requirement from capacity and 65 percent from energy, to capacity and energy revenue requirement percentage splits that varies from 51 percent allocated to capacity in FY 1998 to 42 percent allocated to capacity in FY 2002.

Comments: Five customers commented that they want the provisional rates for CVP commercial firm power to reflect a true cost of service allocation by including investment payment, interest expense, and O&M expense in the capacity revenue requirement. This would result in a capacity and energy revenue requirement split of 70 percent allocated to capacity and 30 percent allocated to energy. Three of the customers commented that they support a ''phasing-in'' approach in achieving a rate design toward the ''true cost of service'' allocation of 70 percent capacity and 30 percent energy. Two other customers commented that they also support the phasing-in approach, but want a split closer the existing rate design in the first year and eventually moving toward a split of 50 percent capacity and 50 percent energy. A representative that represents a coalition of fourteen agricultural CVP power customers, commented that it prefers the existing allocation split, but supports the proposed splits in the provisional rates as an effective balance among Western's customers.

Responses: Western believes its proposed revenue requirement percentage splits between capacity and energy reflects a ''true cost of service'' allocation. The cost of the CVP power generation is split equally between the capacity and energy revenue requirements. The amount of capacity and energy available from the CVP hydroelectric system varies widely because of hydrologic conditions. These conditions can also impact the value of the capacity and energy. Due to this variability, Western believes that an equal split between the capacity and energy revenue requirements for recovery of the cost of the CVP power generation is reflective of its actual costs associated with providing power to all CVP customers. However, in order to utilize the CVP power resources to their maximum benefit, Western supports the CVP generation with capacity and energy purchases, mainly from Northwest resources and from PG&E. Therefore, capacity purchase costs are allocated to capacity and energy purchase costs are allocated to energy. Western believes that all CVP customers benefit from this marketing approach and should pay for these benefits. Because the CVP costs vary annually, the percentage splits also vary annually.

In response to comments relating to ''phasing-in'' the change in the capacity and energy revenue requirement split, Western believes that it is inappropriate for this rate adjustment period. The annual changes in the revenue requirement splits reflect the change in annual costs for providing firm power service.

Comment: One customer commented that the rates being generated are for the benefit of the high load factor customers, and put the low load factor customers at a significant disadvantage. Also, this customer commented that it does not like the financial burden of supplemental thermal energy spread to all customers, since high load factor customers benefit from this arrangement. This customer wants to ''unbundle'' the cost of thermally generated supplemental energy from the cost of CVP hydroelectric power.

Response: Western markets power based on a pool of resources, all of which can be used to serve firm power contractual loads. It is Western's position that Western has an obligation to meet all its contractual commitments. The provisional rates reflect Western's actual costs associated with providing power to all CVP customers, not an individual customer's consumption of capacity or energy. All resources necessary to supply the total CVP commercial power obligation are considered in each kWh and kW of power sales. This results in a homogenous and nondiscriminatory rate design. The generalization that high load factor customers cause the purchase of energy in excess of CVP generation, while low load factor customer do not, is inaccurate. The annual CVP generation follows a pattern of high generation in the spring and summer months, and low generation in the fall and winter months. If low load factor customers were to peak significantly and have high loads in a fall or winter month, a substantial portion of the energy served by Western for such loads is likely from purchased power.

CVP Commercial Firm Power (AERA)

The following comments relate to the CVP annual energy rate alignment, which is an additional cost for firm energy purchases at or above an average load factor of 80 percent.

Comments: Two customers want to eliminate the AERA. They argued that given the conservatism of the forecasts used to develop the rates, the AERA is equivalent to ''wearing both a belt and suspenders''. One other customer wants a redefinition of the AERA to, ''* * * is equal to the pass-through energy costs above the CVP commercial firm energy rate.''

Responses: Western is adopting the change in the definition of the AERA to, ''* * * the difference between the estimated rate for short term energy purchases used in the cost of service study for CVP commercial firm power and the provisional CVP energy rate.'' The AERA provides risk mitigation for the purchase rate assumptions used in this rate adjustment. If the estimated purchase costs are too low and customers increase their energy purchases from Western, then the AERA will provide additional revenues to cover the increased costs of energy. The AERA will be an additional cost for energy purchases from Western at or above an average annual load factor of 80 percent. The AERA replaces the existing energy tier rate and is designed to reduce the impact of purchasing additional CVP support energy on all customers. The AERA applies to only those customers who purchase energy from Western at or above an average annual load factor of 80 percent.

CVP Transmission Services Rates

The following comments relate to the provisional rates for CVP transmission services.

Comment: Three customers commented that the costs of non-transmission items and certain customer specific items in Western's plant-in-service study should not be included as part of the rates development. These customers believe that these items have been either paid for through other sources of funds or paid entirely by a particular customer, and therefore should not be charged to all CVP customers. Examples of items, which the customers gave to be excluded from the calculations are Roseville Substation and COTP lands.

Response: Western reviewed the costs allocated under the non-facility specific O&M and concluded that the some costs allocated for COTP lands was incorrect. This amount totaling $4,060 was omitted from the final rate calculation. In response to the Roseville Substation, there were no plant-in-service costs allocated in the rate calculation, however, there were costs associated with interest expense at an 8.875 percent rate. The interest expense was revised, as explained below.

Comments: Three customers commented that certain interest expenses for various transmission facilities, those with higher interest rates, have been either retired or paid off by Western. It is their understanding that as a result of the 1992–93 settlement between Western and PG&E, Western was not able to refund the large cash settlement from PG&E through the RAC process, and therefore Western used some of the refund to purchase down some of the higher interest loans. These customers believe that it is inappropriate to be charged for interest obligations which do not exist. The three customers want the rate calculations to be based on only the actual interest rates for costs remaining, or be based on average system-wide interest costs.

Responses: Western reviewed the costs included in the plant-in-service study and determined that there was an error in the interest rate calculation for the facilities listed as plant in service (P–I–S). This error has been corrected, and as a result, all interest expenses for repaid investment was excluded from the transmission rate study. The interest associated with the Roseville Substation mentioned above was also excluded. Western applied interest to P–I–S facilities at the interest rates applicable to each project. When a specific interest rate was not identified, a 3.0 percent rate was applied. The average interest rate applied to P–I–S facilities in the CVP transmission rate study calculates to be 3.08 percent.

In order to recognize the P–I–S paid through transmission revenue, Western made an adjustment to account for repayment of transmission investment that have been made during FY 1993 to FY 1997 as follows:

1. The total investment amount for this rate adjustment was reduced by the total payment on investment for five years of the 50-year repayment period of the 1993 rate adjustment.

2. The remaining investment payment amount from the 1993 rate adjustment was amortized over 45 years.

3. The remainder of the total investment for this rate adjustment that was not included in the 1993 rate adjustment was amortized for 50 years, to calculate an annual payment for these investments. The result was deducted from the annual payment.

Comment: Two customers recommended that since the provisional rates represent a net 20 percent increase in the existing CVP transmission services rates, which is a significant change, a ‘‘phasing-in’’ approach would be better for them to have time to adjust. Also, this phasing-in approach would allow time to evaluate the possible impacts from the future California’s Independent System Operator on transmission usage and costs.

Response: Western believes that the CVP transmission rates accurately reflect the cost of providing CVP transmission service. Therefore, Western will not be implementing a ‘‘phasing-in’’ period for the provisional CVP transmission services rates.

Comment: Three customers recommended a formation of a customer group to work with Western on the tracking, monitoring and allocating of Western’s transmission expenses.

Response: At several meetings during the informal public process, Western discussed with the preference customers the transmission rate costs and rate design methodology. The comment recommending a formation of a customer group to work with Western on the tracking, monitoring, and allocating of Western’s transmission expenses is outside the scope of this rate adjustment and public process.

County of Origin Rate for First Preference Customers

The following comments relate to inquiries for a separate county of origin rate for first preference customers.

Comments: Four customers commented that they believe there must be a county of origin rate for first preference customers and encourage Western to recognize the need to ‘‘treat first preference customers in a unique manner, since they are legislated recipients of CVP power’’. These customers want Western to establish a first preference county of origin rate which is reflective of the actual cost of power generation from CVP facilities in those counties. One customer commented that in the past, they have ‘‘been penalized by having to pay for purchased power to meet other customers’ load requirements’ and that they have been ‘‘deprived of most of the first preference benefits.’’ Another customer argued that ‘‘the rights granted by Congress to them should be met first before other Western customers receive extra services’’ and that the provisional rates are ‘‘many times higher than the rates contemplated by Congress as partial mitigation’’.

Responses: The Flood Control Act of 1962 authorized construction of the New Melones Project and specifically granted first preference to preference customers in Calaveras and Tuolumne counties, in a quantity to the extent needed but not to exceed 25 percent of such additional CVP energy resulting from the construction of the New Melones Project power facility and its integration into the CVP system. The Act of August 12, 1955 authorized construction of the Trinity River Division and granted a similar first preference to preference customers in Trinity County, to the extent of 25 percent of such additional energy available from the CVP power system as a result of the construction of the Trinity River Project, as integrated into the CVP system, and who are ready, able and willing to enter into contracts for the energy.

The Acts entitled the preference customers in those counties who are ready, able and willing to enter contracts with Western to a first preference in the purchase of CVP energy to the extent needed, but not to exceed 25 percent and under certain conditions. The authorizing legislation also provides that the Trinity and New Melones projects be integrated and coordinated, from both a financial and an operational standpoint, with the operation of other features of the CVP. In *Trinity County* v. *Harrington* the court determined first preference customers are not entitled to preferential rates based on the operating costs of Trinity and New Melones projects alone, as opposed to operating costs of the CVP system as a whole. The provisional rates for CVP commercial firm power are based on the operation costs of the CVP system as whole, and will be applied to all CVP customers who purchase CVP power from Western. In addition, since the CVP power service provided to first preference customers is the same as that provided to other customers who receive CVP power, the provisional rates for CVP commercial firm power charged to other CVP customers will be the same for the first preference customers.

Other Comments

The following comments relate to the RAC, project use power, allocation of multipurpose joint costs, EA2, energy tier rate, and general rate design.

Comment: The RAC distribution should be reset for each 6-month period rather than the 9-month period. This would enable Western to adjust revenues for wholesale customers more promptly.

Response: The annual maximum RAC credit is $20 million plus the use of EA2 credit from PG&E and/or other adjustments from purchase power contracts. Limiting the distribution of the RAC to 6 months would make it difficult to refund the maximum RAC credit allowed. Using a 9 month distribution ensures most, if not all customers, will receive maximum benefit from the RAC calculation.

Comment: Allocating larger portions of multipurpose joint costs to the CVP power customers must be stopped because it impairs Western's efforts to remain competitive in the new restructured California's electric market.

Response: The Bureau of Reclamation is responsible for the allocation of CVP multipurpose costs. Comments pertaining to the allocation of these costs should be directed to Reclamation during their public participation process on the CVP cost allocation.

Comment: Western needs to rethink its use of the EA2 energy based on its recent discussions with PG&E and work closely with the customers on this matter.

Response: Future use of EA2 can be impacted by many variables, some of which can not be evaluated at this time because information is not available. An example would be the possible impact on EA2 from the divesture of PG&E's generation. Western has based its projections for EA2 usage on the information currently available. The RAC is available to cover possible changes in the costs associated with EA2.

Comment: Project use customers have underpaid Western for project use power during past years in an amount between $15–20 million. Request that Western increase project use revenue collection to bring such balance to zero by the end of this 5-year rate adjustment period. Also request that the project use additional revenue be included in the initial setting of Western's rates, instead of allowing the additional revenue to roll through the RAC.

Response: The amount owed by the project use customers is still being determined. Western is anticipating full payment by December 2004, however the exact timing and magnitude of payments from the project use customers is not known. Given this uncertainty, Western believes it is prudent to exclude any estimated amount in the provisional rates. Any payments made will flow through the annual RAC calculation.

Comments: The proposed CVP energy component of the rates appears marginally competitive. Western should set the rates based on a ''high use'' scenario instead of the ''average use'' scenario. This will give lower rates and the scheduling customers will more likely utilize CVP power. In the event that CVP energy delivery is less than planned, the RAC would be used to meet revenue requirement. It would highly be unlikely that the $20 million RAC limit for revenue recovery would cause a revenue shortfall if rates are based on very high usage and lower than average usage occurred. Western should adopt a higher energy use basis in the derivation of rates.

Responses: In developing the provisional rates, Western performed studies that considered maximum, minimum and average use (power sales) scenarios based on historical sales. The results of these studies indicated that the maximum sales or high sales scenario was not justifiable because of the magnitude of increase from the FY 1996 recorded amounts for firm commercial power sales. The average sales scenario was an appropriate transition given the historical sales levels and the change to the power rates contained in this rate adjustment. Due to the volatility of the electric industry, the $20 million RAC limit may not be sufficient to cover the assumptions of average versus maximum power sales if the actual costs are substantially higher that those projected in this rate adjustment.

Comment: Western's energy forecast for FY 1999 is wrong and the proposed rates undercuts the 1999 market energy rates by over 50 percent. Believes this will have customers purchasing energy as much as possible from Western, thus depleting the EA2 energy and cause a clamor by the high load factor customers for Western to get back into procuring supplemental thermal energy.

Response: The studies Western performed in developing the provisional rates indicate that the EA2 energy will be available throughout the 5-year rate adjustment period. In fact, there is a balance remaining in EA2 after the 5-year period.

Comment: A customer commented it liked the tiered energy rate arrangement since it represented Western's effort toward ''marginal cost'' pricing and caused a reduction in consumption of Western's supplemental thermal energy. This customer recommends that Western adopts a rate form like the existing tier rate and establish a tier rate at the 2.2 to 2.4 cents per kWh range for energy sales over 70 percent load factor.

Response: Western performed an analysis that considered the implementation of an energy tier rate. The methodology and the assumptions used were the same as those used in developing the existing energy tier rate. The result of this analysis indicated that the difference between the base and energy tier rates was minimal. Therefore, Western decided an energy tier rate will not be implemented for this rate adjustment.

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969, 42 U.S.C. 4321 *et seq.*; the Council on Environmental Quality Regulations for implementing NEPA (40 CFR parts 1500 through 1508); and the DOE NEPA Implementing Procedures and Guidelines (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.

Determination Under 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.

Availability of Information

Information regarding this rate adjustment, including power repayment studies, comments, letters, memorandums, and other supporting material made or kept by Western for the purpose of developing the provisional rates, is available for public review in the Sierra Nevada Regional Office, Western Area Power Administration, Office of the Power Marketing Manager, 114 Parkshore Drive, Folsom, California 95630, and the Power Marketing Liaison Office, Room 8G–027, 1000 Independence Avenue SW., Washington, DC 20585.

Submission to the Federal Energy Regulatory Commission

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

Order

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I confirm and approve on an interim basis, effective October 1, 1997, Rate Schedules CV–F9, CV–FT3, CV–NFT3, CV–TPT4, CV–NWT1, CV–PSS1, CV–RFS1, CV–EID1, CV–SPR1, CV–SUR1, COTP–FT1, and COTP–NFT1 for the Central Valley Project and for the California-Oregon Transmission Project of the Western Area Power Administration. The rate schedules will remain in effect on an interim basis, pending confirmation and approval on a final basis by the Federal Energy Regulatory Commission, through September 30, 2002, or until superseded.

Dated: September 19, 1997.

Elizabeth A. Moler,

Deputy Secretary.

Rate Schedule CV–F9

(Supersedes Schedule CV–F8)

Central Valley Project

Schedule of Rates for Commercial Firm Power

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To the commercial firm power customers for general power service supplied through one meter, at one point of delivery, unless otherwise provided by in the service agreement.

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

Monthly rates: Period	Capacity (kW=Month)	Energy (mills/kWh)	AERA (mills/kWh)
10/01/97–09/30/98	$5.03	10.31	2.86
10/01/98–09/30/99	4.37	10.06	3.57
10/01/99–09/30/00	4.31	10.19	3.92
10/01/00–09/30/01	3.81	10.51	4.09
10/01/01–09/30/02	4.02	11.58	3.53

Billing: Demand: The rates listed above for capacity will be the charge per kW of billing demand. The billing demand is the highest 30-minute integrated demand measured or scheduled during the month up to, but not in excess of, the delivery obligation under the power sales contract.

Energy: The rates listed above for energy will be a charge per kWh for all energy use up to, but not in excess of, the maximum kWh obligation of the United States during the month as established under the power sales contract.

Annual Energy Rate Alignment (AERA): The rates listed above for AERA will be an additional charge per kWh for energy purchases at or above an average annual load factor of 80 percent, calculated at the end of each Federal fiscal year (September 30). The AERA is in addition to the CVP energy rate. The billing for the AERA will be based on the following formula:

AERA=(Total kWh − (ALF * Hours in fiscal year * 0.7999)) * AERA rate

Where:

AERA=Annual Energy Rate Alignment
kWh = Energy purchased from Western during a fiscal year.
ALF=Average of monthly billed capacity purchased from Western during a fiscal year.

Adjustments

Billing for Unauthorized Overruns. For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual obligation for capacity and/or energy, such overrun will be billed at 10 times the applicable rates above.

For Revenue Adjustment. The following methodology will be used for the revenue adjustment clause (RAC) calculation:

1. If the actual net revenue is greater than the projected net revenue for the RAC calculation period, a revenue credit will be allocated during the RAC adjustment period. The credit will equal the difference between the actual net revenue and projected net revenue, represented by the following formula:

ANR>PNR; C=ANR − PNR

Where:

ANR=Actual Net Revenue
PNR=Projected Net Revenue
C=Credit

2. If actual net revenue is less than the projected net revenue for the RAC calculation period, a revenue surcharge will be allocated during the RAC adjustment period.

2.1 If the actual net revenue is negative, the surcharge will be equal to the minimum investment payment plus the annual deficit, represented by the following formula:

ANR<PNR and<0; S=MIP+AD

Where:

ANR=Actual Net Revenue
PNR=Projected Net Revenue
MIP=Minimum Investment Payment
AD=Annual Deficit
S=Surcharge

2.2 If the actual net revenue is positive, the surcharge will equal the minimum investment payment less the actual net revenue, represented by the following formula:

ANR<PNR and>0; S=MIP − ANR (if ANR>MIP, S=0)

Where:

ANR=Actual Net Revenue
PNR=Projected Net Revenue
MIP=Minimum Investment Payment
S=Surcharge

Provided, that if the actual net revenue is greater than the minimum investment payment, the surcharge will be equal to zero.

3. The maximum RAC credit allocation will equal $20 million plus the amount of the Pacific Gas and Electric Company refund credit applied to Western power bills for the fiscal year, or other purchase power contract adjustments used in recording associated expense.

4. The maximum allocation for a RAC surcharge will not exceed $20 million.

5. The RAC credit or surcharge will be allocated to each CVP commercial firm power customer based on the proportion of the customer's billed obligation to Western for CVP commercial firm capacity and energy to the total billed obligation for all CVP commercial firm power customers for CVP commercial firm capacity and energy for the RAC calculation period.

6. For purposes of the RAC calculation, the following terms are defined:

6.1 Actual Net Revenue—The recorded net revenue.

6.2 Annual Deficit—The amount the recorded annual expenses, including interest, exceeding recorded annual revenues.

6.3 Minimum Investment Payment—The lesser of 1 percent of the recorded unpaid investment balance at the end of the prior fiscal year that the RAC is being calculated, or the projected net revenue.

6.4 Projected Net Revenue—The annual net revenue available for investment repayment projected in the PRS for the rate case during the fiscal year that the RAC is being calculated (see Table 1).

6.5 RAC Adjustment Period—The period January 1 through September 30, following the RAC calculation period when credits or surcharges will be applied to the power bills.

6.6 RAC Calculation Period—The last recorded fiscal year (October 1 through September 30).

6.7 Recorded Net Revenue—The annual net revenue available for repayment recorded in the PRS for the fiscal year that the RAC is being calculated.

7. Subject to modification by a superseding rate schedule, the final RAC will be allocated to the customers during the period January 1, 2003, to September 30, 2003.

TABLE 1.—PROJECTED NET REVENUE AVAILABLE FOR INVESTMENT REPAYMENT FOR REVENUE ADJUSTMENT CLAUSE

Period	Projected net revenue
October 1, 1997–September 30, 1998.	$5,522,851
October 1, 1998–September 30, 1999.	9,534,973
October 1, 1999–September 30, 2000.	12,196,514
October 1, 2000–September 30, 2001.	17,039,731
October 1, 2001–September 30, 2002.	28,948,352

For Transformer Losses

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

For Power Factor Adjustment

The customer will be required to maintain a power factor at all points of measurement between 95 percent lagging and 95 percent leading. The low power factor charge (LPF Charge) will be applied when the customer does not maintain a 95 percent or greater power factor. The charge for additional kilovolt-ampere reactive (kvar) required to raise the customer's power factor to 95 percent will be calculated by multiplying the customer's monthly maximum peak demand by the LPF Charge for the customer's calculated power factor as provided in the Table 2. The kvar rate in the LPF Charge is $2.50 per kvar.

TABLE 2.—LOW POWER FACTOR CHARGE

Calculated power factor	LPF charge ($ per kW)
0.95	$0.00
0.94	0.09
0.93	0.17
0.92	0.24
0.91	0.32
0.90	0.39
0.89	0.46
0.88	0.53
0.87	0.60
0.86	0.66
0.85	0.73
0.84	0.79
0.83	0.86
0.82	0.92
0.81	0.99
0.80	1.05
0.79	1.12
0.78	1.18
0.77	1.25
0.76	1.32
0.75 & below	1.38

The rules and limitations of the LPF Charge are as follow:

(a) The calculated power factor used to determine if a charge will be assessed is the arithmetic mean of the customer's measured monthly average power factor and their measured monthly on-peak power factor, rounded to the nearest whole percent with 0.5 percent or greater rounded to the next higher percent.

(b) The measured on-peak power factor is equal to the power factor measured during the customer's maximum peak demand for each month, as recorded at the customer's point of delivery. In the event of multiple occurrences of the same peak demand, the lowest associated power factor will be used. The measured average power factor will be the average power factor for the billing month. If the customer has multiple points of delivery, the power factor will be determined from totalized information from the points of delivery. The monthly average and on-peak power factors are those recorded for CVP power only.

(c) The upper limit for both the monthly average and measured on-peak power factors is 95 percent. No credit will be given for customers operating between 100 percent and 95 percent power factors.

(d) The LPF Charge will be applicable to calculated power factors less than 95 percent, lagging or leading.

(e) Customers that have a monthly maximum peak demand less than or equal to 50 kW will not be subject to the LPF Charge.

(f) Western may waive the LPF Charge for good cause in whole or in part.

Rate Schedule CV–FT3

(Supersedes Schedule CV–FT2)

Central Valley Project

Schedule of Rate for Firm Transmission Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To firm transmission service where power is received into the CVP system at points of interconnection with other systems and transmitted and delivered to points of delivery on the CVP system as agreed to by the parties.

Character and Conditions of Service: Transmission service for three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery. Transmission service includes scheduling, system control and dispatch service, and reactive supply and voltage control service needed to support the transmission service provided.

Rate: Firm Transmission Service Charge: $0.51 per kW-month.

Billing: The rate listed above will be applied monthly to the maximum amount of capacity reserved, payable whether utilized or not.

Adjustments

For Losses

Losses incurred in connection with the transmission and delivery of power under this rate schedule will be accounted for as agreed to by the parties.

Rate Schedule CV–NFT3

(Supersedes Schedule CV–NFT2)

Central Valley Project

Schedule of Rate for Non-Firm Transmission Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To non-firm transmission service where power is received into the CVP system at points of receipt with other systems and transmitted and delivered, subject to the availability of transmission capacity, to points of delivery on the CVP system as agreed to by the parties.

Character and Conditions of Service: Transmission service on an intermittent basis for capacity, three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery. Transmission service includes scheduling, system control and dispatch service, and reactive supply and voltage control service needed to support the transmission service provided.

Rate: Non-firm Transmission Service Charge: 1.00 mill per kWh.

Billing: The rate listed above will be applied monthly to the maximum amount of capacity reserved, payable whether utilized or not.

Adjustments

For Losses

Losses incurred in connection with the transmission and delivery of power under this rate schedule will be accounted for as agreed to by the parties.

Rate Schedule CV–TPT4

(Supersedes Schedule CV–TPT3)

Central Valley Project

Schedule of Rate for Transmission of CVP Power by Others

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To power service customers of the CVP who require transmission service by a third party to receive power sold by Western.

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

Rate Formula: When Western utilizes transmission facilities, other than its own, in providing service under a customer's power sales contract, and costs are incurred by Western for the use of such facilities, the customer will pay all costs, including transmission losses, incurred in the delivery of such power. The transmission losses chargeable to the customer will be those losses which are in excess of the ''at or above 44-kV'' transmission losses specified by Contract No. 14–06–200–2948A. For billing purposes, transmission losses will be added to the meter readings of the power and energy delivered to the customer under the customer's power sales agreement with Western.

Rate Schedule CV–NWT1

Central Valley Project

Schedule of Rate for Network Transmission Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To customers of the CVP who receive network transmission service, subject to the availability of transmission capacity, to points of delivery specified in the service agreement.

Character and Conditions of Service: Transmission service for three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery. Transmission service includes scheduling, system control and dispatch service, and reactive supply and voltage control service needed to support the transmission service provided.

Rate Formula: The rate formula for network transmission service is the product of the network customer's load ratio share times one twelfth ($\frac{1}{12}$) of the annual network transmission revenue requirement. The load ratio share is based on the network customer's hourly load, including its designated network load not physically interconnected with the CVP transmission system, coincident with the monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved capacity) point-to-point transmission service.

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

Adjustments

For Losses

Losses incurred in connection with the transmission and delivery of power under this rate schedule will be accounted for in accordance with the service agreement.

Rate Schedule CV–PSS1

Schedule of Rate for Power Scheduling Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To customers receiving power scheduling service from Western.

Character and Conditions of Service: Power scheduling service provides for the scheduling of resources to meet loads and reserve requirements.

Rate: $75.80 per hour.

Billing: The rate listed above will be applied to the number of hours required by Western staff to perform the power scheduling service. A power scheduling service charge will be specified in the service agreement.

Rate Schedule CV–RFS1

Central Valley Project

Schedule of Rates for Regulation and Frequency Response Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To customers receiving regulation and frequency response service from Western.

Character and Conditions of Service: Regulation and frequency response service provides generation to match resources and loads on a real-time continuous basis.

Rates: Regulation and Frequency Service Charge: Monthly: $1.48 per kW-month; Weekly: $0.3360 per kW-week; Daily: $0.0480 per kW-day.

Billing: The rates listed above will be applied to the maximum service amount in kilowatts agreed to in the service agreement, payable whether utilized or not.

Rate Schedule CV–EID1

Central Valley Project

Schedule of Rate for Energy Imbalance Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To customers receiving energy imbalance service from Western.

Character and Conditions of Service: Energy imbalance service provides energy when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month. The hourly deviation, in megawatt units, is the net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.

Rates Formula

Within Limits of Deviation Band

Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP commercial firm power, then in effect.

Outside Limits of Deviation Band

(i) Positive Deviations—no charge, lost to the system.

(ii) Negative Deviations—during on-peak hours, the greater of (1) 3 times the composite rate for CVP commercial firm power, then in effect; or (2) any additional cost incurred. During off-peak hours, the greater of (1) the composite rate for CVP commercial firm power, then in effect; or (2) any additional cost incurred.

Billing: The billing determinants for the above rates formula will be specified in the service agreement.

Rate Schedule CV–SPR1

Central Valley Project

Schedule of Rates for Spinning Reserve Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To customers receiving spinning reserve service from Western.

Character and Conditions of Service: Spinning reserve service provides capacity that is available the first ten minutes to take load and is synchronized with the power system.

Rates: Spinning Reserve Service Charge: Monthly: $1.35 per kW-month; Weekly: $0.3024 per kW-week; Daily: $0.0432 per kW-day; Hourly: $0.0018 per kWh.

Billing: The rates listed above will be applied to the maximum service amount in kilowatts agreed to in the service agreement, payable whether utilized or not.

Rate Schedule CV–SUR1

Central Valley Project

Schedule of Rates for Supplemental Reserve Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To customers receiving supplemental reserve service from Western.

Character and Conditions of Service: Supplemental reserve service provides capacity that is not synchronized with the power system, but can be available to serve load within ten minutes.

Rates: Supplemental Reserve Service Charge: Monthly: $1.27 per kW-month; Weekly: $0.2856 per kW-week; Daily: $0.0408 per kW-day; Hourly: $0.0017 per kWh.

Billing: The rates listed above will be applied to the maximum service amount in kilowatts agreed to in the service agreement, payable whether utilized or not.

Rate Schedule COTP–FT1

California-Oregon Transmission Project

Schedule of Rates for Firm Transmission Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To firm transmission service customers where power is received into the COTP system at points of interconnection with other systems and transmitted and delivered to points of delivery on the COTP system as agreed to by the parties.

Character and Conditions of Service: Transmission service for three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery. Transmission service includes scheduling, system control and dispatch service, and reactive supply and voltage control service needed to support the transmission service provided.

Rates: October 1, 1997—September 30, 1998: $1.83 per kW-month. October 1, 1998—September 30, 2002: $1.34 per kW-month.

Billing: The rates listed above will be applied monthly to the maximum amount of capacity reserved, payable whether utilized or not.

Adjustments

For Losses

Losses incurred in connection with the transmission and delivery of power under this rate schedule will be accounted for as agreed to by the parties.

Rate Schedule COTP–NFT1

California-Oregon Transmission Project

Schedule of Rates for Non-Firm Transmission Service

Effective: October 1, 1997.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To non-firm transmission service customers where power is received into the COTP system at points of receipt with other systems and transmitted and delivered, subject to the availability of transmission capacity, to points of delivery on the COTP system as agreed to by the parties.

Character and Conditions of Service: Transmission service on an intermittent basis for capacity, three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery. Transmission service includes scheduling, system control and dispatch service, and reactive supply and voltage control service needed to support the transmission service provided.

Rates: October 1, 1997–September 30, 1998: 2.19 mills per kWh; October 1, 1998–September 30, 2002: 1.45 mills per kWh.

Billing: The rates listed above will be applied monthly to the maximum amount of capacity reserved, payable whether utilized or not.

Adjustments

For Losses

Losses incurred in connection with the transmission and delivery of power and energy under this rate schedule will be accounted for as agreed to by the parties.

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BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Colorado River Storage Project—Notice of Order Confirming and Approving an Extension of the Firm Transmission Service Rate—WAPA–74

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of rate order

SUMMARY: This action is to extend the existing Colorado River Storage Project firm transmission rate until March 31, 1998. Without this action, the existing firm transmission rate will expire September 30, 1997 and no rate will be in effect for this service.

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.

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 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).

Pursuant to Delegation Order No. 0204–108 and existing Department of Energy procedures for public