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# Part II

# Department of Energy

## Western Area Power Administration

## Central Valley Project and California-Oregon Transmission Project—Rate Order No. WAPA–95; Notice

## DEPARTMENT OF ENERGY

### Western Area Power Administration

### Central Valley Project and California-Oregon Transmission Project—Rate Order No. WAPA–95

**AGENCY:** Western Area Power Administration, DOE.

**ACTION:** Notice of rate order.

**SUMMARY:** Western Area Power Administration's Administrator has confirmed and approved Rate Order No. WAPA–95 and Rate Schedules CV–F10, CV–FT4, CV–NFT4, CV–TPT5, CV–NWT2, CV–RFS2, CV–EID2, CV–SPR2, CV–SUR2, CV–PSS2, CV–SCS1, COTP–FT2, and COTP–NFT2. These rate schedules place into effect provisional rates for the Central Valley Project (CVP) firm power and transmission services, ancillary services, power scheduling service, and scheduling coordinator service, and the California-Oregon Transmission Project (COTP) transmission services of the Western Area Power Administration (Western). The provisional rates will be in effect for an interim period 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 repay required investment in the allowable period.

**DATES:** The provisional rates will be effective the first day of the first full billing period beginning on or after April 1, 2001, until FERC confirms, approves, and places them into effect on a final basis. These rates will stay in effect through December 31, 2004, or until other rates replace them.

**FOR FURTHER INFORMATION CONTACT:** Ms. Debbie Dietz, Rates Manager, Western Area Power Administration, Sierra Nevada Customer Service Region, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4453, e-mail ddietz@wapa.gov.

**SUPPLEMENTARY INFORMATION:** The Deputy Secretary of Energy approved the existing Rate Schedules CV–F9 for CVP commercial firm power, CV–FT3, CV–NFT3, CV–TPT4, and CV–NWT1 for CVP transmission services, CV–RFS1, CV–EID1, CV–SPR1, CV–SUR1 for CVP ancillary services, CV–PSS1 for power scheduling service, and COTP–FT1 and COTP–NFT1 for COTP transmission services on September 19, 1997 (Rate Order No. WAPA–77, 62 FR 50924, September 29, 1997). FERC confirmed and approved the rate schedules on January 8, 1998, under FERC Docket No. EF97–5011–000 (82 FERC ¶62,006). The existing rate schedules became effective October 1, 1997, for the period ending September 30, 2002.

Rate Schedule CV–F10 supersedes Rate Schedule CV–F9. Under Rate Schedule CV–F9, the composite rate on April 1, 2001, is 18.56 mills per kilowatthour (mills/kWh). The provisional rates for CVP firm power in Rate Schedule CV–F10 will result in an overall composite rate of 20.08 mills/kWh on April 1, 2001. This results in an increase of about 8 percent when compared with the existing CVP commercial firm power rates under Rate Schedule CV–F9.

Western also developed provisional rates for CVP firm power with the transmission revenue requirement removed from the CVP firm power revenue requirement. These rates are also in Rate Schedule CV–F10. These rates will apply if Western joins the California Independent System Operator (CAISO) or a Regional Transmission Organization (RTO) and if the CAISO or RTO uses Western's transmission revenue requirement to develop a regional transmission rate. The provisional rates for CVP firm power with the transmission revenue requirement removed in Rate Schedule CV–F10 will result in an overall composite rate of 18.51 mills/kWh on April 1, 2001. This results in a decrease of less than 1 percent when compared with the existing CVP commercial firm power rates under Rate Schedule CV–F9. In addition, both sets of CVP firm power provisional rates include any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule approved or accepted by FERC, under which Western take service will be passed through to the appropriate customers.

Rate Schedules CV–FT4, CV–NFT4, CV–TPT5, and CV–NWT2 replace Rate Schedules CV–FT3, CV–NFT3, CV–TPT4, and CV–NWT1, respectively. Provisional formula rates developed for CVP transmission services are consistent with FERC Order No. 888. Under Rate Schedules CV–FT3 and CV–NFT3, the CVP transmission services rates on April 1, 2001, are $0.51/kWmonth for firm service and 1.00 mill/kWh for nonfirm service. On April 1, 2001, the provisional formula rate in Rate Schedule CV–FT4 results in an estimated rate of $.70/kWmonth for firm CVP transmission service, a 37-percent increase when compared with the existing rate. Based on an Open Access Transmission Tariff Service Agreement to provide transmission service in the future, on October 1, 2001, the provisional formula rate in Rate Schedule CV–FT4 results in an estimated rate of $.56/kWmonth for CVP firm transmission service. On April 1, 2001, the provisional formula rate in Rate Schedule CV–NFT4 results in a rate of 1.00 mill/kWh for CVP nonfirm transmission service, which is the same rate as the existing rate. If the rates resulting from the proposed formula rate are higher than other transmission rates in California, firm or nonfirm transmission service for 1 year or less may be sold at lower rates. The provisional rate for transmission of CVP power by others in Rate Schedule CV–TPT5 is a pass through cost and results in no change from the existing Rate Schedule CV–TPT4 on April 1, 2001.

The provisional formula rate for network integration transmission service in Rate Schedule CV–NWT2 will be the same as the existing formula rate for network integration transmission service under Rate Schedule CV–NWT1.

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

The provisional rates in Rate Schedule CV–RFS2, effective April 1, 2001, for monthly regulation and frequency response service will result in a 69-percent increase for the same service when compared to the existing monthly rate under Rate Schedule CV–RFS1. The provisional rates for regulation and frequency response service are: monthly—$2.496/kWmonth, weekly—$.574/kWweek, and daily—$.082/kWday. The weekly and daily rates are derived from the monthly rate.

The provisional formula rate for energy imbalance service under Rate Schedule CV–EID2 will be the same as the existing formula rate for energy imbalance service under Rate Schedule CV–EID1.

The provisional rates in Rate Schedule CV–SPR2, effective April 1, 2001, for monthly spinning reserve service will result in a 118-percent increase for the same service when compared to the existing monthly rate under Rate Schedule CV–SPR1. The provisional rates for spinning reserve service are: monthly—$2.946/kWmonth, weekly—$.672/kWweek, daily—$.096/kWday, and hourly—$.0040/kWh. The weekly, daily, and hourly rates are derived from the monthly rate.

The provisional rates in Rate Schedule CV–SUR2, effective April 1, 2001, for monthly supplemental reserve service will result in a 96-percent increase for the same service when compared to the existing monthly rate under Rate Schedule CV–SUR1. The provisional rates for supplemental reserve service are: monthly—$2.491/kWmonth, weekly—$.574/kWweek, daily—$.082/kWday, and hourly—$.0034/kWh. The weekly, daily, and hourly rates are derived from the monthly rates.

The provisional rate for power scheduling service in Rate Schedule CV–PSS2 is $76.65 per hour. This results in a 1-percent increase compared to the existing rate in Rate Schedule CV–PSS1 of $75.80 per hour on April 1, 2001.

Scheduling coordinator service is a new service. The provisional rate for scheduling coordinator service is $76.65 per hour and is designed to recover only the cost incurred for providing the service.

Rate Schedules COTP–FT2 and COTP–NFT2 replace Rate Schedules COTP–FT1 and COTP–NFT1. Provisional formula rates developed for COTP firm and nonfirm transmission services are consistent with FERC Order No. 888. The estimated rates from the provisional formula rate in Rate Schedule COTP–FT2 for firm transmission service for Western's share of the COTP will result in a 30-percent decrease in the summer, a 16-percent decrease in the winter, and a 25-percent decrease in the spring compared to the existing rate of $1.34/kWmonth in Rate Schedule COTP–FT1 on April 1, 2001. The estimated rates from the provisional formula rate for COTP firm transmission service beginning in April 2001 are: summer—$.94/kWmonth, winter—$1.12/kWmonth, and spring—$1.00/kWmonth. The estimated rates from the provisional formula rate in Rate Schedule COTP–NFT2 for COTP nonfirm transmission service will result in a 11-percent decrease in the summer, a 6-percent increase in the winter, and a 6-percent decrease in the spring compared to the existing rate in Rate Schedule COTP–NFT1 of 1.45 mills/kWh on April 1, 2001. The estimated rates from the provisional formula rate for COTP nonfirm transmission service beginning April 2001 are: summer—1.29 mills/kWh, winter—1.54 mills/kWh, and spring—1.37 mills/kWh.

**Provisional Rates for CVP Firm Power**

On December 13, 2000, Western provided updates to the proposed CVP firm power rates. There were no updates to any of the other rates proposed by Western.

The CVP firm power rates include Project Dependable Capacity support purchase costs and pass through of FERC-accepted or -approved costs or credits. Western also updated the Revenue Adjustment Clause (RAC). The limit for the RAC credit and surcharge is $20 million, $10 million for the October to December 2004 period, plus any purchase or exchange power contract adjustments.

Western developed two sets of provisional firm power rates. One set of rates includes the transmission revenue requirement, and the other set of rates removes the transmission revenue requirement. Both sets are designed to recover an annual revenue requirement that includes investment repayment, interest, purchase power costs, operation and maintenance (O&M) expense, and FERC-accepted or -approved charges or credits. Western used a cost-of-service study to divide the projected annual revenue requirement for firm power between capacity and energy. Based on this study, the capacity revenue requirement includes: (1) 100 percent of capacity purchase costs; (2) 50 percent of the investment repayment; (3) 50 percent of the interest expense; (4) 50 percent of the O&M expense allocated to power; and (5) 100 percent of CVP and COTP transmission expense. Projected CVP and COTP transmission revenue and 50 percent of projected CVP project use revenue reduce the annual costs that make up the capacity revenue requirement. The energy revenue requirement includes: (1) 100 percent of energy purchase costs; (2) 50 percent of the investment repayment; (3) 50 percent of the interest expense; and (4) 50 percent of the O&M expense allocated to power. Projected surplus power revenue and 50 percent of projected CVP project use revenue reduce the annual costs that make up the energy revenue requirement.

For the provisional power rates with the transmission revenue requirement removed, Western used a cost-of-service study to divide the projected annual revenue requirement for firm power between capacity and energy. Based on this study, the capacity revenue requirement includes: (1) 100 percent of capacity purchase costs; (2) 50 percent of the investment repayment; (3) 50 percent of the interest expense; and (4) 50 percent of the O&M expense allocated to power. Fifty percent of the projected CVP project use revenue reduces the annual costs that make up the capacity revenue requirement. The energy revenue requirement includes: (1) 100 percent of energy purchase costs; (2) 50 percent of the investment repayment; (3) 50 percent of the interest expense; and (4) 50 percent of the O&M expense allocated to power. Projected surplus power revenue and 50 percent of the projected CVP project use revenue reduce the annual costs that make up the energy revenue requirement. Additionally, under both sets of CVP firm power rates, Western will also pass through to each appropriate customer any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by FERC under which Western takes service.

Rate Schedule CV–F9 and Rate Schedule CV–F10 include adjustment clauses for power factors, low voltage losses, and revenue.

*Power Factor Adjustment*

The power factor adjustment is a low power factor (LPF) charge that applies when the customer does not maintain a calculated 95 percent or greater power factor.

*Low Voltage Loss Adjustment*

The low voltage loss adjustment applies to the billed amounts for low voltage CVP firm power deliveries on the Pacific Gas and Electric Company (PG&E) system.

*Revenue Adjustment*

The RAC provides for a comparison between the projected net revenues in the rate adjustment power repayment study (PRS) to the actual net revenues. If the actual net revenue is more than the projected net revenue, CVP firm power customers receive a credit. If actual net revenue is less than the projected net revenue, CVP firm power customers may pay a surcharge, if needed, to make a minimum investment payment. The limit for the RAC credit or surcharge is $20 million, $10 million for the October to December 2004 period, plus any purchase or exchange power contract adjustments during the fiscal year (FY) for which the RAC is being calculated. The RAC is calculated annually and the associated distribution of the RAC credit or surcharge occurs during a 9-month period on power bills issued January through September. For customers whose RAC credits cannot be fully credited through nine equal monthly amounts, Western has the option to increase the RAC credit during August and September. The first RAC calculation under the provisional rates will be based on the net revenue for FY 2001, including revenues and expenses for October 2000 to March 2001, which is outside of the rate adjustment period. A RAC will be calculated for October through December 2004. The RAC credit or surcharge for October through

December 2004 is applied to the April to September 2005 bills.

### Provisional Formula Rates for CVP Transmission Services

A revenue requirement that recovers: (1) the costs for facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines); (2) the nonfacilities costs allocated to transmission; and (3) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry is the basis for the provisional formula rates in Rate Schedules CV–FT4 and CV–NFT4 for CVP firm and nonfirm transmission services. Western will revise as of April 30 of each year the rates from the provisional formula rates based on updated data. In addition to the annual update on April 30 of each year, Western will also revise the rates if there is a change in the numerator or denominator that results in a firm transmission rate change of at least $.05/kWmonth. The provisional formula rates include Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service. The provisional formula rates apply to existing CVP firm transmission service and future point-to-point transmission service. If the rates from the provisional formula rates are higher than other transmission rates in California, firm or nonfirm transmission service for 1 year or less may be sold at lower rates.

### Provisional Rate for Transmission of CVP Power by Others

Western will pass on to the appropriate customer any transmission service costs it incurs for delivering CVP power over a third party's transmission system. The provisional rate in Rate Schedule CV–TPT5 will be adjusted automatically as third party transmission costs are adjusted.

### Provisional Formula Rate for Network Integration Transmission Service

If Western offers network integration transmission service, it will be consistent with FERC Order No. 888. The provisional formula rate for network integration transmission service is the product of the network customer's load ratio share times 1⁄12 of the annual network transmission revenue requirement. The load ratio share is the network customer's hourly load coincident with Western's monthly CVP transmission system peak, minus the coincident peak for all firm CVP point-to-point transmission service, plus the reserved capacity of all firm point-to-point transmission service customers. A revenue requirement that recovers: (1) the costs for facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines); (2) the nonfacilities costs allocated to transmission; and (3) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry is the basis for the provisional formula rate for network integration transmission service. The provisional formula rate includes Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service.

### Provisional Rates for Ancillary Services

Western will offer six ancillary services consistent with FERC Order No. 888. Two of the ancillary services—scheduling, system control and dispatch service and reactive supply and voltage control service—are included with the sale of CVP and/or COTP transmission services. The appropriate transmission services rates include the costs for these two ancillary services. Subject to availability, Western will offer regulation and frequency response, energy imbalance, spinning reserve, and supplemental reserve services. Except for the two ancillary services provided with the sale of CVP and/or COTP transmission services, the basis for availability and type of ancillary services is excess resources at the time the service is requested.

### Provisional Rate for Power Scheduling Service

The power scheduling service schedules resources to meet load and reserve requirements. The provisional rate for power scheduling service is designed to recover only the cost to supply the service.

### Provisional Rate for Scheduling Coordinator Service

Scheduling coordinator service is a new service. It includes scheduling, real-time dispatching, and financial settlements with the CAISO and/or power exchanges. The provisional rate for scheduling coordinator service is designed to recover only the cost to supply the service.

### Provisional Formula Rates for COTP Transmission Services

A revenue requirement that recovers: (1) Western's share of costs for facilities that support the transfer capability of the COTP; (2) Western's share of the nonfacilities costs allocated to transmission; and (3) any transmission-related costs that Western incurs due to electric industry restructuring or other changes in the industry is the basis for the provisional formula rates in Rate Schedules COTP–FT2 and COTP–NFT2 for COTP firm and nonfirm transmission services. The rates from the provisional formula rate will be updated each season to coincide with the changes in the California-Oregon Intertie transfer capability. The provisional formula rates include Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control needed to support the transmission service. The provisional formula rates apply to existing COTP firm and nonfirm transmission service and future point-to-point transmission service. If the rates from the provisional formula rate are higher than other transmission rates in California, firm or nonfirm transmission service for 1 year or less may be sold at lower rates.

### Procedural Requirements

The provisional rates for CVP firm power and transmission services, ancillary services, power scheduling service, scheduling coordinator service, and COTP transmission services are developed under the Department of Energy Organization Act (42 U.S.C. 7101–7352.), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts that specifically apply 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 Western's Administrator; and (2) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to FERC. In Delegation Order No. 0204–172, effective November 24, 1999, the Secretary of Energy delegated the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary. On April 10, 2001, by Amendment No. 4 to Delegation Order No. 0204–108, the Secretary of Energy delegated to Western's Administrator the authority to confirm, approve, and place into effect on an interim basis the rates in the Central Valley Project and California-Oregon Transmission Project-Rate Order No. WAPA–95.

Western followed the DOE procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions (10 CFR part 903) to develop these provisional rates.

Rate Order No. WAPA–95, confirming, approving, and placing the proposed CVP firm power and transmission services, ancillary services, power scheduling service, and scheduling coordinator service rates, and the COTP transmission services rates into effect on an interim basis, is issued. New Rate Schedules CV–F10, CV–FT4, CV–NFT4, CV–TPT5, CV–NWT2, CV–RFS2, CV–EID2, CV–SPR2, CV–SUR2, CV–PSS2, CV–SCS1, COTP–FT2, and COTP–NFT2 will be submitted promptly to FERC for confirmation and approval on a final basis.

Dated: April 13, 2001.

**Michael S. Hacskaylo,**

*Administrator.*

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

These rates are developed under the Department of Energy Organization Act (42 U.S.C. 7101–7352), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts that specifically apply to the project involved, were transferred to and vested in the Secretary of Energy (Secretary).

By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to Western's Administrator; and (2) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the FERC. In Delegation Order No. 0204–172, effective November 24, 1999, the Secretary delegated the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary. On April 10, 2001, by Amendment No. 4 to Delegation Order No. 0204–108, the Secretary of Energy delegated to Western's Administrator the authority to confirm, approve, and place into effect on an interim basis the rates in the Central Valley Project and California-Oregon Transmission Project-Rate Order No. WAPA–95. Existing DOE procedures for public participation in power and transmission rate adjustments are found in 10 CFR part 903. Procedures for approval of Power Marketing Administration rates are found in 18 CFR part 300.

**Acronyms and Definitions**

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

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| Administrator | The Administrator of the Western Area Power Administration. |
| Ancillary Services | Those services necessary to support the transfer of electricity while maintaining reliable operation of the transmission system following good utility practice. Federal Energy Regulatory Commission Order No. 888, Docket Nos. RM95–8–000 and RM94–7–001, issued April 24, 1996, generally describe ancillary services. |
| CAISO | The California Independent System Operator Corporation. A state chartered, nonprofit corporation that controls the transmission facilities of all participating transmission owners and dispatches certain generating units and loads. |
| COI | The California-Oregon Intertie. It is three 500-kilovolt lines linking California and Oregon making up the California-Oregon Transmission Project and Pacific Alternating Current Intertie transmission lines. The Western Systems Coordinating Council establishes the seasonal transfer capability for the California-Oregon Intertie. |
| COTP | The California-Oregon Transmission Project. A 500-kilovolt transmission project in which Western has part ownership. |
| CRD | Contract rate of delivery. The maximum amount of capacity made available to a preference customer for a period specified under a contract. |
| CVP | The Central Valley Project. 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. |
| Capacity | The electric capability of a generator, transformer, transmission circuit or other equipment. It is expressed in kilowatts. |
| Capacity Rate | The rate that states the charge for capacity. It is expressed in dollars per kilowatt and applied to each kilowatt delivered to each customer. |
| Composite Rate | The rate for firm power. The annual revenue requirement for firm power divided by the total annual energy sales. It is expressed in mills per kilowatthour and used for comparison purposes. |
| Contract 2947A | Contract No. 14–06–200–2947A, as amended. The Western Area Power Administration's contract with the Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric companies for extra high voltage transmission and exchange service. |
| Contract 2948A | Contract No. 14–06–200–2948A, as amended. The Pacific Gas and Electric Company's contract with the Western Area Power Administration for the sale, interchange, and transmission of power. |
| Corps | United States Army Corp of Engineers. |
| Customer | An entity with a contract and receiving service from the Western Area Power Administration's Sierra Nevada Customer Service Region. |
| DLL | Designated load level. The simultaneous load level at which the Western Area Power Administration buys capacity from the Pacific Gas and Electric Company at the lower of two capacity rates under Contract No. 14–06–200–2948A. |
| DOE Order RA6120.2 | An order dealing with power marketing administration financial reporting and repayment criteria. |
| EA2 | Energy Bank Account No. 2 between the Western Area Power Administration and the Pacific Gas and Electric Company under Contract No. 14–06–200–2948A. |

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| Energy | Measured in terms of the work it is capable of doing over a period of time. It is expressed in kilowatthours. |
| Energy Rate | The rate that states the charge for energy. It is expressed in mills per kilowatthour and applied to each kilowatthour delivered to each customer. |
| FY | Fiscal year. October 1 to September 30. |
| Firm | A type of product and/or service 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). |
| kV | Kilovolt. The electrical unit of measure of electric potential that equals 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 equals one thousand watts. |
| kWh | Kilowatthour. The electrical unit of energy that equals one thousand watts in one hour. |
| kWmonth | Kilowattmonth. The electrical unit of the monthly amount of capacity. |
| Load Factor | The ratio of average load in kilowatts supplied during a specified period to the peak or maximum load in kilowatts occurring in that period. |
| MW | Megawatt. The electrical unit of capacity that equals one million watts or one thousand kilowatts. |
| Mill | A monetary denomination of the United States that equals one tenth of a cent or one thousandth of a dollar. |
| Mills/kWh | Mills per kilowatthour. The unit of charge for energy. |
| NEPA | National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*). |
| Net Revenue | Revenue remaining after paying all annual expenses. |
| Nonfirm | A type of product and/or service that may not be available at the time requested by the customer. |
| Northwest | Northwest United States, including Oregon and Washington. |
| PDC | Project Dependable Capacity. A negotiated amount of capacity and associated energy available from the CVP under contract 2948A. |
| Power | Capacity and energy. |
| Power Factor | The ratio of real to apparent power at any given point and time in an electrical circuit. Generally it is expressed as a percentage ratio. |
| Preference | The requirements of Reclamation law which state that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936 (Reclamation Project Act of 1939, section 9(c), 43 U.S.C. 485h(c)). |
| Project Use | Power used to operate Central Valley Project facilities, pursuant to Reclamation law. |
| Provisional Rates | Rates the Deputy Secretary of Energy has confirmed, approved, and placed in effect on an interim basis. |
| Rate Brochure | A November 17, 2000, document prepared for public distribution that explains the rationale and development of the rates in this rate order. |
| 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. |
| Secretary | Secretary of the United States Department of Energy. |
| Sierra Nevada Region | The Sierra Nevada Customer Service Region of the Western Area Power Administration. |
| Western | United States Department of Energy, Western Area Power Administration. |
| Withdrawable | Power that may be withdrawn under certain conditions. |

**Effective Date**

The provisional rates will take effect on the first day of the first full billing period beginning on or after April 1, 2001, and will be in effect pending FERC's approval of them or substitute final rates. The approved rates will stay in effect through December 31, 2004, or until superseded.

**Public Notice and Comment**

Western followed 10 CFR part 903, Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, in developing these rates. The steps Western took to involve interested parties in the rate development process are:

1. The proposed rate adjustment started on August 25, 2000, with a letter to all CVP preference customers and interested parties announcing an informal rate workshop on August 31, 2000. Two additional informal rate meetings were held on September 20, 2000, and October 5, 2000, in Folsom, California, to discuss Western's proposed rates. Western explained the rationale for the rate adjustment, presented rate designs and methodologies, and answered questions.

2. A **Federal Register** notice published on November 8, 2000 (65 FR 66989), officially announced the proposed rates for the CVP and COTP, started the public consultation and comment period, and announced the public information and public comment forums.

3. On November 13, 2000, Western's Sierra Nevada Customer Service Region sent a letter to all CVP preference customers and interested parties announcing the times and locations for two public forums.

4. On November 17, 2000, 1 p.m., Western held a public information forum in Folsom, California. Western gave detailed explanations of the proposed rates for the CVP and COTP, supplied a list of issues that could change the proposed rates, answered questions, and gave notice that it would supply additional information at the public comment forum. A rate brochure and handout were made available.

5. On December 13, 2000, 1 p.m., Western held a public comment forum in Folsom, California. Western presented updated proposed rates for CVP firm power, gave a detailed explanation of the updates to the proposed rates, answered questions, and distributed information about the updated rates. Western then gave the public an opportunity to comment for the record. Two representatives made oral comments.

6. Western received four comment letters during the consultation and comment period, which ended December 29, 2000. Western considered all comments received during the comment period.

**Project Description**

Initially authorized by Congress in 1935, CVP is a large water and power system that covers about one-third of the state of California. Legislation set the purposes of CVP in priority as: (1) Improvement of navigation; (2) river regulation; (3) flood control; (4) irrigation; and (5) power. The CVP Improvement Act of 1992 added fish and wildlife as a priority between irrigation and power.

The CVP is within the Central Valley and Trinity River basins of California. It 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, 10 powerplants with a maximum operating capability of about 2,021 MW, about 946 circuit-miles of high voltage transmission lines, 15 substations, and 16 communication sites. Reclamation operates the water control and delivery system and all of the powerplants except the San Luis Unit, which the State of California operates for Reclamation.

The Emergency Relief Appropriations Act of 1935 authorized Reclamation to build the CVP, including Shasta and Keswick Dams on the Sacramento River. The initial authorization included powerplants at Shasta and Keswick Dams along with high voltage transmission lines to transmit power from Shasta and Keswick Powerplants to the Tracy Pumping Plant and to integrate Federal hydropower into other electric systems.

Additional CVP facilities were authorized by Congress through a series of laws. The American River Division was authorized in 1944 and includes the Folsom Dam and Powerplant and the Nimbus Dam and Powerplant on the American River. The Trinity Dam and Powerplant, Judge Francis Carr Powerplant, and Spring Creek Powerplant were authorized as part of the Trinity River Divison in 1955. The San Luis Unit was authorized in 1960 and includes the B. F. Sisk San Luis Dam and San Luis Reservoir, O'Neill and Dos Amigos Pumping Plants, and William R. Gianelli Pump-Generator. In 1962, Congress authorized for integration into CVP New Melones, which is a Corps project.

In 1964, Congress authorized the 500-kV Intertie. Western has a 400 MW entitlement of transmission capacity on the Intertie. On July 31, 1967, Reclamation (Western's predecessor), PG&E, the Southern California Edison Company, and the San Diego Gas & Electric Company entered into Contract 2947A to coordinate the operation of the Intertie to transmit electric power between the Northwest and the Pacific Southwest.

In marketing Federal hydroelectric power generated from the CVP, Western currently has 80 preference and 34 project use customers serving an estimated 2 million people.

In 1967, PG&E and Reclamation (Western's predecessor) executed Contract 2948A, allowing for the sale, interchange, and transmission of electric capacity and energy between Western and PG&E. Contract 2948A also includes provisions for integrating power generated from the CVP with Western's 400 MW of entitlement on the Intertie. The contract also states PG&E will support a maximum simultaneous demand of 1,152 MW for preference customers through 2004. If CVP power cannot meet obligations to preference customers, Contract 2948A gives Western the right to purchase capacity and energy from PG&E to meet those requirements. Any energy in excess of project use loads and Western's obligations to preference customers can be sold to PG&E through an energy 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. Types of preference customers include: (1) Irrigation and water districts; (2) public utility districts; (3) municipalities; (4) Federal agencies; (5) State agencies; and (6) rural electric cooperatives.

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

Western's preference customer maximum simultaneous demand of 1,152 MW excludes project use loads. 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. Despite the simultaneous demand limit, Western has contractual obligations to serve about 1,502 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-mile, 500-kV transmission project that electrically interconnects the Northwest to California with the third alternating current intertie. Operational since March 1993, COTP interconnects with the transmission systems of the Northwest at Captain Jack Substation and with the Pacific Southwest by its connection near the Tesla Substation to the existing Intertie. Project owners include Western and several non-Federal participants.

**Power Repayment Study**

Western prepares a power repayment study (PRS) each FY to decide if 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 including DOE Order RA6120.2, and authorizing legislation. The CVP rate adjustment PRS reflects an increase in customer load, purchase power costs, Reclamation O&M costs, and CVP and COTP transmission and CVP project use revenues. It also reflects the suspension in Western's Northwest purchase power contracts. The PRS shows enough revenue to pay all annual costs, including interest expense, and repays investment in the allowable period.

**Transmission Cost-of-Service Study**

The CVP and COTP firm and nonfirm transmission provisional formula rates consist of two components. Component 1 recovers the cost of the CVP transmission system and COTP. Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes. A cost-of-service study determines component 1. The CVP transmission system and COTP have separate cost-of-service studies that are used for the firm and nonfirm provisional formula rates. The studies identify the costs associated with facilities that support the transfer capability of the CVP transmission system and COTP, excluding generation facilities and radial lines.

There are two primary reasons for the increase in transmission costs in the CVP cost-of-service study. One reason is facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines) are included as transmission. The second reason is the increase in transmission O&M expenses. O&M not directly charged to a facility is charged to transmission based on a ratio of transmission plant to total plant.

The transmission costs from the COTP cost-of-service study have not changed significantly. However, the termination of a contractual obligation to provide standby transmission service increased the amount of capacity available for sale. The amount of COTP capacity used in component 1 of the formula rate will change with the seasonal transfer capability of the COI.

## Existing and Provisional Rates

*CVP Firm Power*

The provisional rates for CVP firm power are designed to recover an annual revenue requirement that includes the investment repayment, interest, purchase power costs, O&M expenses, and any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule approved or accepted by FERC under which Western takes service.

Western also developed provisional rates for CVP firm power with the transmission revenue requirement removed. These rates would apply if Western joins the CAISO or an RTO and if the CAISO or RTO uses the transmission revenue requirement to develop a regional transmission rate. Western has not made a decision on joining the CAISO or RTO. The decision to join the CAISO or an RTO is not part of this rate adjustment process. These rates are also designed to recover an annual revenue requirement that includes investment repayment, interest, purchase power, O&M expense, and any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by FERC.

A comparison of the existing rates and both sets of provisional rates for CVP firm power are in the next two tables.

COMPARISON OF EXISTING AND PROVISIONAL RATES, CVP FIRN POWER WITH THE TRANSMISSION REVENUE REQUIREMENT INCLUDED

| Rate Period | Existing Rates (Effective 04/01/01 to 09/30/01) | Provisional Rates | Percent Change |
|---|---|---|---|
| Composite Rate (mills/kWh): | | | |
| 04/01/01 to 09/30/01 | 18.56 | 20.08 | 8 |
| 10/01/01 to 09/30/02 | | 23.83 | 28 |
| 10/01/02 to 09/30/03 | | 24.63 | 33 |
| 10/01/03 to 09/30/04 | | 24.73 | 33 |
| 10/01/04 to 12/31/04 | | 30.83 | 66 |
| Capacity Rate ($/kWmonth): | | | |
| 04/01/01 to 09/30/01 | 3.81 | 3.44 | (10) |
| 10/01/01 to 09/30/02 | | 3.73 | (2) |
| 10/01/02 to 09/30/03 | | 3.89 | 2 |
| 10/01/03 to 09/30/04 | | 3.86 | 1 |
| 10/01/04 to 12/31/04 | | 3.80 | |
| Energy Rate (mills/kWh): | | | |
| 04/01/01 to 09/30/01 | 10.51 | 14.01 | 33 |
| 10/01/01 to 09/30/02 | | 17.68 | 68 |
| 10/01/02 to 09/30/03 | | 18.22 | 73 |
| 10/01/03 to 09/30/04 | | 18.38 | 75 |
| 10/01/04 to 12/31/04 | | 24.97 | 138 |

Note: In addition to the provisional firm power rates above, any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted by FERC will be passed through to the appropriate customer(s).

COMPARISON OF EXISTING AND PROVISIONAL RATES, CVP FIRM POWER WITH THE TRANSMISSION REVENUE REQUIREMENT REMOVED

| Rate Period | Existing Rates (Effective 04/01/01 to 09/30/01) | Provisional Rates | Percent Change |
|---|---|---|---|
| Composite Rate (mills/kWh): | | | |
| 04/01/01 to 09/30/01 | 18.56 | 18.51 | |
| 10/01/01 to 09/30/02 | | 22.48 | 21 |
| 10/01/02 to 09/30/03 | | 23.26 | 25 |
| 10/01/03 to 09/30/04 | | 23.41 | 26 |
| 10/01/04 to 12/31/04 | | 29.47 | 59 |
| Capacity Rate ($/kWmonth): | | | |
| 04/01/01 to 09/30/01 | 3.81 | 2.55 | (33) |
| 10/01/01 to 09/30/02 | | 2.91 | (24) |
| 10/01/02 to 09/30/03 | | 3.08 | (19) |
| 10/01/03 to 09/30/04 | | 3.05 | (20) |
| 10/01/04 to 12/31/04 | | 2.92 | (23) |
| Energy Rate (mills/kWh): | | | |
| 04/01/01 to 09/30/01 | 10.51 | 14.01 | 33 |
| 10/01/01 to 09/30/02 | | 17.68 | 68 |
| 10/01/02 to 09/30/03 | | 18.18 | 73 |
| 10/01/03 to 09/30/04 | | 18.38 | 75 |
| 10/01/04 to 12/31/04 | | 24.97 | 138 |

Note: Customers are required to buy transmission at an additional cost under these rates. In addition to the provisional firm power rates above, any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted by FERC will be passed through to the appropriate customer(s).

*CVP Transmission Services and Transmission of CVP Power by Others*

The provisional formula rate for CVP firm transmission includes two components.

$$\text{Component 1} = \frac{\text{transmission revenue requirement}}{\text{CVP capacity} + \text{total transmission capacity under long-term contracts}}$$

Component 1 =transmission revenue requirement CVP capacity + total transmission capacity under long-term contracts
Component 1 is the ratio of Western's transmission revenue requirement (less revenue credits) to the sum of the maximum operating capacity under normal operating conditions of the northern CVP powerplants (CVP capacity) and the total transmission capacity under long-term contract between Western and other parties. The Northern CVP powerplants are Judge Francis Carr, Folsom, Keswick, Nimbus, Shasta, Spring Creek, and Trinity. Western will revise the rate from component 1 of the provisional formula rate based on updated data as of April 30 of each year. Western will also revise the rate from component 1 if there is a change in the numerator or denominator that results in a rate change of at least $.05/kWmonth.

Component 2 is for any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes. The costs in component 2, as well as any changes to these costs, will be passed on to each appropriate transmission customer.

The provisional formula rates for CVP transmission services are based on a revenue requirement that recovers: (1) The costs of facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines); (2) the nonfacilities costs allocated to transmission; and (3) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The provisional formula rate includes Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service. The provisional formula rates apply to existing CVP firm and nonfirm transmission services and future point-to-point transmission services. If the rates from the provisional formula rates are higher than other transmission rates in California, then firm or nonfirm transmission service for 1 year or less may be sold at lower rates. The provisional rate for transmission of CVP power by others is a pass through cost, which is the same as the existing rate. This table compares the existing and the estimated rates from the provisional formula rates for CVP transmission services and for transmission of CVP power by others.

COMPARISON OF EXISTING AND PROVISIONAL FORMULA RATES CVP FIRM AND NONFIRM TRANSMISSION RATE SCHEDULES

| Rate period | Existing rates (effective 04/01/01 to 09/30/01) | Estimated rates from the provisional formula rates | Percent rates change |
|---|---|---|---|
| Firm ($/kWmonth): | | | |
| 04/01/01 to 09/30/01 | 0.51 | 0.70 | 37 |
| 10/01/01 to 04/30/02 | | 0.56 | 10 |
| Nonfirm (mills/kWh): | | | |
| 04/01/01 to 04/30/02 | 1.00 | 1.00 | |

COMPARISON OF EXISTING AND PROVISIONAL FORMULA RATES TRANSMISSION OF CVP POWER BY OTHERS RATE SCHEDULE

| Rate period | Existing rate (effective 04/01/01 to 09/30/01) | Provisional rate | Percent change |
|---|---|---|---|
| 04/01/01 to 12/31/04 | Pass through Cost | Pass through Cost | Not Applicable. |

*Network Integration Transmission Service*

If Western offers network integration transmission service, it will be made available consistent with FERC Order No. 888. The provisional formula rate for network integration transmission service includes two components. Component 1 is the product of the network customer's load ratio share, times 1⁄12 of the annual network transmission revenue requirement. The load ratio share is the network customer's hourly load coincident with Western's monthly CVP transmission system peak, minus the coincident peak for all firm CVP point-to-point transmission service, plus the reserved capacity of all firm point-to-point transmission service customers. Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes. The costs in component 2, as well as any changes to these costs, will be passed through to each appropriate transmission customer as part of the network integration transmission revenue requirement. The provisional formula rate for network integration transmission service is based on a revenue requirement that recovers: (1) the cost for facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines); (2) the nonfacilities costs allocated to transmission; and (3) any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes. The provisional formula rate includes Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service.

*Ancillary Services*

Western will offer six ancillary services consistent with FERC Order No. 888. Two of the ancillary services will be supplied with the sale of CVP and/or COTP transmission services. These are scheduling, system control and dispatch, and reactive supply and voltage control services. The remaining four ancillary services are regulation and frequency response, energy imbalance, spinning reserve, and supplemental reserve. Availability and type of ancillary service will be based on excess resources at the time the service is requested, except for the two ancillary services supplied in conjunction with the sale of CVP and/or COTP transmission services. The appropriate transmission services rates include costs for scheduling, system control and dispatch service and reactive supply and voltage control service. The major factor for the increase in the spinning reserve, supplemental reserve, and regulation and frequency response services rates is the increase in Reclamation power O&M expenses. This table compares the existing and the provisional rates.

COMPARISON OF EXISTING AND PROVISIONAL ANCILLARY SERVICES RATES CVP ANCILLARY SERVICE RATE SCHEDULES

| Ancillary service type | Existing rates | Provisional rates | Percent change |
|---|---|---|---|
| Scheduling, System Control and Dispatch Service. | Appropriate transmission rates include Western's cost. | Appropriate transmission rates include Western's cost. | NA |
| Reactive Supply and Voltage Control Service. | Appropriate transmission rates include Western's cost. | Appropriate transmission rates include Western's cost. | NA |
| Regulation and Frequency Response Service. | Monthly: $1.48/kWmonth | Monthly: $2.496/kWmonth | 69 |
| | Weekly: $.336/kWweek | Weekly: $0.574/kWweek | 71 |
| | Daily: $.048/kWday | Daily: $0.082/kWday | 71 |
| Energy Imbalance Service | *Within Limits of Deviation Band:* Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are are to 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 then in effect for CVP firm power. | *Within Limits of Deviation Band:* Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are are to 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 then in effect for CVP firm power. | NA |
| | *Outside Limits of Deviation Band:* Positive Deviations—The greater of no charge, or any additional cost incurred. Negative Deviations—during on-peak hours is the greater of 3 times the composite rate then in effect for CVP firm power or any additional cost incurred. During off-peak hours is the greater of the composite rate then in effect for CVP firm power or any additional cost incurred. | *Outside Limits of Deviation Band:* Positive Deviations—The greater of no charge, or any additional cost incurred. Negative Deviations—during on-peak hours is the greater of 3 times the composite rate then in effect for CVP firm power or any additional cost incurred. During off-peak hours is the greater of the composite rate then in effect for CVP firm power or any additional cost incurred. | |
| Spinning Reserve Service | Monthly: $1.35/kWmonth | Monthly: $2.946/kWmonth | 118 |
| | Weekly: $.3024/kWweek | Weekly: $0.672/kWweek | 121 |
| | Daily: $.0432/kWdayHourly: $.0018/kWh | Daily: $0.096/kWday | 122 |
| | | Hourly: $0.0040/kWh | 122 |
| Supplemental Reserve Service | Monthly: $1.27/kWmonth | Monthly: $2.491/kWmonth | 96 |
| | Weekly: $.2856/kWweek | Weekly: $0.574/kWweek | 100 |
| | Daily: $.0408/kWday | Daily: $0.082/kWday | 100 |
| | Hourly: $.0017/kWh | Hourly: $0.0034/kWh | 100 |

*Power Scheduling Service*

Western supplies power scheduling service for the scheduling of resources to meet load and reserve requirements. The provisional rate of $76.65 per hour will apply to the estimated time for each customer's service. The rate is designed to recover only the cost incurred for supplying the service.

*Scheduling Coordinator Service*

Scheduling coordinator service is a new service for scheduling, real-time dispatching, and financial settlements with the CAISO and/or power exchanges. The provisional rate of $76.65 per hour will apply to the estimated time for each customer's service. The rate is designed to recover only the cost incurred for supplying the service.

*Provisional Formula Rates for COTP Transmission Services*

The provisional formula rate for COTP transmission includes two components.

$$\text{Component 1} = \frac{\text{transmission revenue requirement}}{\text{Western's share of COTP seasonal capacity}}$$

Component 1 is the ratio of the transmission revenue requirement (less revenue credits) to Western's share of COTP seasonal capacity. Western will update the rate from component 1 at least 15 days before the start of each season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes. The costs in component 2, as well as any changes to these costs, will be passed on to each appropriate transmission customer.

The provisional rates for COTP transmission service are based on a revenue requirement that recovers: (1) Western's share of costs for facilities that support the transfer capability of the COTP; (2) Western's share of the nonfacilities costs allocated to transmission; and (3) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The provisional formula rates include Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service. The provisional formula rates apply to existing COTP firm and nonfirm transmission services and future point-to-point transmission services. If the estimated rates from the provisional formula rates are higher than other transmission rates in California, firm or nonfirm transmission service for 1 year or less may be sold at lower rates. No generation resources or loads are directly connected to the COTP, so network integration transmission service is not offered for the COTP.

This table compares the existing and estimated rates from the provisional formula rates for transmission services for Western's share of the COTP.

COMPARISON OF EXISTING AND PROVISIONAL FORMULA RATES, COTP TRANSMISSION RATE SCHEDULES

| Rate Period | Existing Rates | Estimated Rates from Provisional Formula Rates | Percent change |
|---|---|---|---|
| Firm Transmission Rate ($/kWmonth): | | | |
| 04/01/01 to 03/31/02 | 1.34 | Summer—.94 | (30) |
| | | Winter—1.12 | (16) |
| | | Spring—1.00 | (25) |
| Nonfirm Transmission Rate (mills/kWh): | | | |
| 04/01/01 to 03/31/02 | 1.45 | Summer—1.29 | (11) |
| | | Winter—1.54 | 6 |
| | | Spring—1.37 | (6) |

**Certification of Rates**

Western's Administrator certified that the provisional rates for CVP firm power, CVP transmission services, transmission of CVP power by others, network integration transmission service, ancillary services, power scheduling service, scheduling coordinator service, and COTP transmission services are the lowest possible rates consistent with sound business principles. The provisional rates were developed under administrative policies and applicable laws.

**Discussion**

*CVP Firm Power*

According to Reclamation law, Western must establish power rates sufficient to recover operation, maintenance, and purchase power expenses, and repay the Federal Government's investment. Rates must also recover interest expenses on the unpaid balance of facilities' investments, replacements and additions, and certain nonpower costs in excess of the irrigation users' ability to repay.

A FERC order issued January 8, 1998, confirmed and approved the existing CVP commercial firm power rates for October 1, 1997, through September 30, 2002. Under Rate Schedule CV–F9 for FY 2001, the composite rate is 18.56 mills/kWh, the base energy rate is 10.51 mills/kWh, and the capacity rate is $3.81/kWmonth. The provisional rates for CVP firm power result in an overall composite rate increase of about 8 percent on April 1, 2001. On a composite rate basis, the provisional rates increase during the rate case period compared to the existing rates due primarily to increased purchased power costs. To use CVP power resources to their maximum benefit, Western supports CVP generation with capacity and energy purchases mainly from PG&E. The provisional rates increase after April to September 2001 due to the depletion of EA2 in September 2001. The increases in FY 2002 and FY 2003 are due to increases in prices for short-term purchases and power from PG&E. In FY 2004, these increases are offset by decreases in O&M and other expenses. The significant increase in rates during October through December 2004 recovers short-term power purchase costs for PDC support due to lower CVP generation during those months. Western will also pass through to each appropriate customer any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by FERC.

The provisional rates for CVP firm power with the transmission revenue requirement removed in Rate Schedule CV–F10 will result in an overall composite rate of 18.51 mills/kWh on April 1, 2001. This results in a change of less than 1 percent when compared with the existing rates under Rate Schedule CV–F9.

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 is used to recover the CVP power generation cost, which reflects its actual costs associated with providing power to all CVP customers.

The existing rates under Rate Schedule CV–F9 reflect a 5-year average split of 46 percent to capacity and 54 percent to energy. Both sets of provisional rates are based on allocating the total annual CVP revenue requirement split between capacity and energy in this way:

1. For the rates that include the transmission revenue requirement, the capacity revenue requirement includes 100 percent of capacity purchase costs, 100 percent of CVP and COTP

transmission expense, and 50 percent of the annual CVP investment repayment, interest expense, and power O&M expense allocated to power. Projected CVP and COTP transmission revenue and 50 percent of projected CVP project use revenue reduce the annual costs that make up the capacity revenue requirement. The capacity revenue requirement for the rates that have the transmission revenue requirement removed is the same, except the CVP and COTP transmission expense and revenue are excluded from the calculation.

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 power. Projected surplus power revenue and 50 percent of projected CVP project use revenue reduce annual costs that make up the energy revenue requirement.

3. Western will pass through to each appropriate customer any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by FERC under which Western takes service.

The resulting percentage splits for the provisional rates with the transmission revenue requirement included vary from 19 percent allocated to capacity during October 1, 2004, through December 31, 2004, to 30 percent allocated to capacity in FY 2001, primarily due to changes in purchase power costs each year. The average split for the rate period is 25 percent to capacity and 75 percent to energy. This table is the annual percentage splits between the capacity and energy revenue requirements.

ENERGY/CAPACITY SPLITS WITH THE TRANSMISSION REVENUE REQUIREMENT INCLUDED

| Effective period | Capacity (percent) | Energy (percent) |
|---|---|---|
| 04/01/01–9/30/01 | 30 | 70 |
| 10/01/01–9/30/02 | 26 | 74 |
| 10/01/02–9/30/03 | 26 | 74 |
| 10/01/03–9/30/04 | 26 | 74 |
| 10/01/04–12/31/04 | 19 | 81 |
| Average for the 5 periods | 25 | 75 |

The resulting percentage splits for the provisional rates with the transmission revenue requirement removed vary from 15 percent allocated to capacity during October 1, 2004, through December 31, 2004, to 24 percent allocated to capacity in FY 2001, primarily due to changes in purchase power costs each year. The average split for the rate period is 21 percent to capacity and 79 percent to energy. This table is the annual percentage splits between the capacity and energy revenue requirements.

ENERGY/CAPACITY SPLITS WITH THE TRANSMISSION REVENUE REQUIREMENT REMOVED

| Effective period | Capacity (percent) | Energy (percent) |
|---|---|---|
| 04/01/01–9/30/01 | 24 | 76 |
| 10/01/01–9/30/02 | 21 | 79 |
| 10/01/02–9/30/03 | 22 | 78 |
| 10/01/03–9/30/04 | 21 | 79 |
| 10/1/04–12/31/04 | 15 | 85 |
| Average for the 5 periods | 21 | 79 |

*Power Factor Adjustment*

The power factor adjustment under existing Rate Schedule CV–F9 will continue and is included in the provisional rates for CVP firm power. The low power factor charge (LPF charge) will continue to encourage preference customers to monitor and maintain power factors at 95 percent or greater. Western will continue the existing LPF charge under Rate Schedule CV–F10, which includes a rate of $2.50/kvar for additional kvar required to raise the customer's power factor to 95 percent. The $2.50/kvar rate is 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 computed power factor used to decide 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. As recorded at the customer's point of delivery, the measured on-peak power factor is equal to the power factor measured during a customer's maximum peak demand for each month. If multiple occurrences of the same peak demand occur, 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–F9 will continue and is included in the provisional rates for CVP firm power. A loss adjustment factor of 1.035 will be applied to the billed amounts for low voltage CVP power deliveries on PG&E's system under Contract 2948A.

*Revenue Adjustment Clause*

The RAC provides for a comparison between the projected net revenues in the rate adjustment PRS to the actual net revenues. If the actual net revenue is more than the projected net revenue, CVP preference customers receive a credit. If actual net revenue is less than the projected net revenue, CVP preference customers may pay a surcharge, if needed, to make a minimum investment payment. The limit for the annual RAC credit or surcharge is $20 million, plus any purchase or exchange power contract adjustments during the FY for which the RAC is being calculated. The RAC is calculated annually and the associated distribution of the RAC credit or surcharge occurs during a 9-month period on power bills issued January through September. For customers whose RAC credits cannot be fully credited through nine equal monthly amounts, Western has the option to increase the RAC credit during August and September. The FY 2001 RAC calculation will be based on the net revenue for FY 2001, including revenues and expenses for October 2000 to March 2001, which is outside of the rate adjustment period. A RAC will be calculated for October through December 2004. The maximum RAC credit or surcharge for October through December 2004 is $10 million plus any purchase or exchange power contract adjustments applied to the April to September 2005 bills.

*CVP Transmission Services and Transmission of CVP Power by Others*

Provisional formula rates developed for CVP firm and nonfirm transmission services are consistent with FERC Order No. 888. The estimated rate from the provisional formula rate for firm CVP transmission service on April 1, 2001, is $0.70/kWmonth, a 37-percent increase from the existing rate of $0.51/kWmonth under Rate Schedule CV–FT3. Based on an Open Access Transmission Tariff service agreement to supply CVP transmission service in the future, on October 1, 2001, the estimated rate from the provisional formula rate in Rate Schedule CV–FT4 will be $.56/kWmonth. The estimated rate resulting from the formula rate for CVP nonfirm transmission service will be 1.00 mills/kWh, which is the same as the existing rate under Rate Schedule CV–NFT3. There are two primary reasons for the increase in CVP firm transmission rates. The first reason is including in the transmission revenue requirement the costs associated with facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines). The second reason is the increase in transmission O&M expenses. O&M not directly charged to a facility is charged to transmission based on a ratio of transmission plant to total plant.

Western will pass on to the CVP customer transmission service costs Western incurs in the delivery of CVP power over a third party's transmission system. Annual transmission pass through 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 service to preference customers.

*Network Integration Transmission Service*

If Western offers network integration transmission service, it will be consistent with FERC Order No. 888. Due to existing contractual arrangements, Western may not be able to supply network integration transmission service; however, a formula rate is included in case Western offers the service.

*Ancillary Services*

Western allocates most of its power resources to preference entities under long-term commitments; therefore, availability and type of ancillary service will be based on excess resources at the time the service is requested, except for the two ancillary services supplied with the sale of CVP and/or COTP transmission services. The appropriate transmission services rates include costs for scheduling, system control and dispatch and reactive supply and voltage control services.

The provisional rates for ancillary services are designed to recover the costs for these services. The primary reason for the 69-percent increase in the monthly regulation and frequency response service rate, 118-percent increase in the monthly spinning reserve rate, and 96-percent increase in the monthly supplemental reserve service rate is the increase in the Reclamation O&M expenses. Standards and practices used in the electric utility industry are the basis for the provisional rate for energy imbalance service. Western used a detailed cost-of-service study for developing the provisional rates for regulation and frequency response, spinning reserve, and supplemental reserve services. These rates are based on the costs of CVP facilities used in supplying the service. The CVP facilities used to supply 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 Powerplant and the W. R. Gianelli pump-generator, which makes them unavailable for supplying the services.

*Power Scheduling Service*

Western supplies power scheduling service for scheduling resources to meet load and reserve requirements. The provisional rate for power scheduling service is designed to recover only the cost incurred by Western for supplying the service. This results in a 1-percent increase compared to the existing rate in Rate Schedule CV–PSS1 of $75.80 per hour on April 1, 2001. The provisional rate includes two cost components. The first is the FY 2000 hourly cost for dispatcher and/or scheduler resources, escalated for the rate adjustment period to calculate an average hourly cost. The second is an hourly cost for equipment necessary to supply the service.

*Scheduling Coordinator Service*

Scheduling coordinator service is a new service offered by Western that allows for scheduling, real-time dispatching, and financial settlements with the CAISO and/or power exchanges. The rate is designed to recover only the cost incurred for supplying the service. The provisional rate includes two cost components. The first is the FY 2000 hourly cost for scheduling, dispatching, settlements, supervisory control and data acquisition, and other resources, escalated for the rate adjustment period to calculate an average hourly cost. The second is an hourly cost for equipment necessary to supply the service.

*COTP Transmission Services*

Provisional formula rates developed for COTP firm and nonfirm transmission services are consistent with FERC Order No. 888. The estimated rates from the provisional formula rate for firm transmission service for Western's share of the COTP will result in a 30-percent decrease in the summer, a 16-percent decrease in the winter, and a 25-percent decrease in the spring compared to the existing rate of $1.34/kWmonth on April 1, 2001. The estimated rates from the provisional formula rate for COTP firm transmission service for April 1, 2001, through March 31, 2002, are: summer—$.94/kWmonth, winter—$1.12/kWmonth, and spring—$1.00/kWmonth. The estimated rates from the provisional formula rate for nonfirm COTP transmission service will result in an 11-percent decrease in the summer, a 6-percent increase in the winter, and a 6-percent decrease in the spring compared to the existing rate of 1.45 mills/kWh on April 1, 2001. The estimated rates from the provisional formula rates for COTP nonfirm transmission service for April 1, 2001, through March 31, 2002, are: summer—1.29 mills/kWh, winter—1.54 mills/kWh, and spring—1.37 mills/kWh. In the previous rate case, Western developed COTP rates based on the entire transfer capability of the COI, which is 4,800 MW. However, due to the variability of the COI transfer capability, which impacts Western's share of the COTP capacity available for sale, Western developed formula rates for COTP transmission services. The primary factor for the decrease in the firm and nonfirm COTP rates is the termination of a contractual obligation to provide standby transmission service which increases the capacity available for sale.

**Statement of Revenue and Related Expenses**

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

CVP COST EVALUATION RATE PERIOD

[Revenues and Expenses, in thousands of dollars]

| | Existing rates FY 1998–FY 2002 | Provisional rates April 1, 2001—December 2004 | Difference |
|---|---|---|---|
| Total revenues | 824,651 | 928,925 | 104,274 |
| Revenue distribution: | | | |
| O&M | 216,776 | 187,600 | (29,176) |
| Purchase power | 390,689 | 609,623 | 218,934 |
| Transmission | 80,335 | 57,229 | (23,106) |
| Interest | 54,536 | 21,486 | (33,050) |
| Other | 9,073 | 13,568 | 4,495 |
| Investment repayment | 73,242 | 39,419 | (33,823) |

Note: The revenues and expenses for the existing rates are for 5 years. Those for the provisional rates are for 3 years and 9 months.

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

CVP COMPARISON OF COST EVALUATION RATE PERIOD

[Average Annual Revenues and Expenses, in thousands of dollars]

| | Existing rates average annual | Provisional rates average annual | Difference |
|---|---|---|---|
| Total Revenues | 164,930 | 247,713 | 82,783 |
| Revenue distribution: | | | |
| O&M | 43,355 | 50,027 | 6,672 |
| Purchase power | 78,138 | 162,566 | 84,428 |
| Transmission | 16,067 | 15,261 | (806) |
| Interest | 10,907 | 5,730 | (5,177) |
| Other | 1,815 | 3,618 | 1,803 |
| Investment repayment | 14,648 | 10,512 | (4,136) |

**Basis for Rate Development**

The existing rates for CVP commercial firm power, CVP transmission services, transmission of CVP power by others, network transmission service, ancillary services, and power scheduling service in Rate Schedules CV–F9, CV–FT3, CV–NFT3, CV–TPT4, CV–NWT1, CV–RFS1, CV–EID1, CV–SPR1, CV–SUR1, and CV–PSS1, expire September 30, 2002. Scheduling coordinator service is a new service offered by Western. The rate adjustment contains rates that replace the existing rates and adds a rate for the new service. The adjusted rates reflect increases in customers' CVP power purchases, purchase power costs, and Reclamation O&M costs. The adjusted rates also reflect the pass through of FERC-accepted or -approved costs or credits, and changes in transmission rate methodology. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense and FERC-accepted or -approved costs or credits, and repayment of required investment in the allowable period. The provisional rates are scheduled to go in effect on April 1, 2001, and remain in effect through December 31, 2004.

The provisions for power factor adjustment, low voltage loss adjustment, and revenue adjustment are part of the provisional rates for CVP firm power. The provisions and methodologies for power factor adjustment and low voltage loss adjustment are not being modified and will remain as specified in Rate Schedule CV–F9. The methodology for revenue adjustment has been modified to reflect the expanded limit for the RAC credit or surcharge of $20 million, $10 million for October to December 2004, plus any purchase power or exchange contract adjustments during the FY for which the RAC is being calculated.

**Update to the Proposed Rates**

During the public process, changes were made to the proposed rates for CVP firm power. On November 17, 2000, during the public information forum, Western told all interested parties of its intent to update the proposed CVP firm power rates. Western presented these updates to the proposed rates at the December 13, 2000, public comment forum. The updates are detailed below.

*Firm Power*

1. Western added purchase power costs required to support PDC. Western expects PDC support purchases to occur in the rate case period due to recent purchases made for that purpose.

2. Western has suspended its Northwest purchase power contracts. As a result, Western will be buying more capacity from PG&E at the DLL and will also be buying more energy from PG&E. The contract suspensions also cause EA2 to be depleted in September 2001.

3. Western will also pass any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by FERC.

4. Western updated PG&E rates for capacity and energy based on current agreements. Western also increased the capacity purchased under the DLL.

5. Western also made adjustments to data in the firm power rate design model to reconcile that data to the data in the PRS and CVP transmission rate cost-of-service study.

6. In the RAC limit, Western included exchange energy contract language.

After the public process was complete it was necessary to change the CVP power repayment study as was contemplated during the December 13, 2000, public comment forum. This change is due to purchase power costs for PDC support for October 2000 through March 2001. As a result of this change, there is less net revenue and slightly higher interest expense for the rate adjustment period, but all costs are recovered and repayment criteria met within the allowable timer limits. No changes were made to composite power rates. The energy and capacity rates changed slightly due to the change in net revenue and interest expense.

**Comments**

During the public consultation and comment period, Western received 5 written comments from 4 customers on the rate adjustment. In addition, two customer representatives commented during the December 13, 2000, public comment forum. All comments received by the end of the public consultation and comment period, December 29, 2000, were reviewed and considered in this rate order.

Written comments were received from the following sources: City of Redding (California), Trinity County Public Utility District (California), City of Roseville (California), Sacramento Municipal Utility District (California)

Comments received addressed the CVP energy rates, forecasted market rates, RAC limits, simplification of CVP firm power rate structure, pass through of FERC-approved charges or credits, power rates with the transmission revenue requirement removed, CAISO pass through costs, and CVP transmission rates. The following summarizes comments received and Western's responses to those comments. Specific comments are used for clarification where necessary.

*CVP Power Rates*

*Comment:* Allowing adjustment without limitation to CVP energy rates leaves the customer with no ability to predict its Western costs. The rates should be developed using contractual conditions as they exist today. Under that premise, Western's major wholesale power costs are predictable enough that unlimited changes to the energy rate are unnecessary. If at some point in the future a significant change occurs to Western's cost structure, Western should implement another rate case.

*Response:* The comment addresses a rate proposal that was discussed during the informal process and was not part of the proposed or updated proposed rates for CVP firm power.

*Comment:* The forecasted market rates for Western's long-term Northwest contracts are too high.

*Response:* The suspension of the Northwest contracts for the rate adjustment period was included in the updates to the proposed rates. This comment is not relevant to the updated proposed rates.

*Comment:* The annual RAC limit of $20 million ($10 million for October through December 2004) plus any adjustment to Western's purchased power contract expenses is not appropriate. This RAC limit provides no assurance of maximum cost to customers and no guidance to Western on a reasonable range of operating cost variance. Western should develop a hedging strategy for PDC support purchases to keep Western within a RAC limit of $20 million.

*Response:* Western is willing to work with the customers on developing a hedging strategy for PDC support purchases. As part of the updates to the proposed rates, Western added language to the RAC limit to allow for exchanges of power in addition to purchases of power, which should aid in limiting Western's exposure to market prices for PDC support. Due to the many factors outside of Western's control that can contribute to the need for PDC support purchases, Western feels it is prudent to retain the updated proposed RAC limit. These factors include changes in project water deliveries due to environmental requirements, project use pumping, and unscheduled maintenance outages. Maintaining the updated proposed RAC limit ensures timely repayment of project expenses and capital investment.

*Comment:* A rate schedule without tiered capacity or energy rates or the Annual Energy Rate Alignment (AERA) is appreciated. There is no legitimate purpose for Western to apply an AERA once EA2 is depleted.

*Response:* Western simplified the rate structure because the benefit of using the tiered rates and AERA is negligible, given the condition of the electric power industry.

*Pass Through of FERC-Approved Charges and Credits*

*Comment:* The pass through of FERC-approved charges or credits is unacceptable. The pass through results in an unlimited right to change CVP power rates and makes it impossible to predict Western power costs. If there is a material change in the expected overall purchase power costs to Western, Western should initiate another rate case. If the cumulative effect of all FERC pass through costs increases Western's composite rates by more than 10 percent, Western should complete a new rate case within 6 months.

*Response:* Western feels it is necessary to include the pass through of FERC-approved charges or credits in the updated proposed rates because of Western's exposure to changes in FERC-approved charges or credits under its existing contracts that support Western's power marketing program. In the recent past, there has been an increase in Western costs that were approved by FERC subject to refund. Western needs to recover FERC-approved charges or refund credits from its customers in a timely manner to ensure appropriate repayment of project expenses and capital investment. Additionally, adopting this comment could impact our ability to finance our purchase power program. Western understands customers' concerns about the inability to predict Western's costs and will make every effort to notify the customers of pending changes to Western's costs due to FERC actions. FERC-approved charges or credits can go into effect within 60 days. Western cannot complete a rate case in that time. When FERC makes a final determination on costs paid by Western under its existing contracts, Western will evaluate the need for another rate case.

*CAISO/Electric Utility Restructuring*

*Comment:* It is premature for Western to set rate policy that speculates on Western's joining the CAISO or an RTO, or the pass through of costs that may exist after Western joins an CAISO or an RTO.

*Response:* Western's decision to join the CAISO or an RTO is not part of this rate process. However, Western believes it is prudent to develop rates that would accommodate Western's joining the CAISO or an RTO, particularly in light of FERC Order No. 2000. The pass through of CAISO- or RTO-related costs can occur independent of Western's decision to join or not to join the CAISO or an RTO. For example, in June 2000 FERC approved, subject to refund, payment of Reliability Service costs that are CAISO-related costs, by Western customers.

*CVP Transmission Service Rates*

*Comment:* The rate increase up to $.70/kW-month and then down to $.56/kW-month is not appropriate and creates rate shock for the transmission customers. There has been no real change in the transmission service or addition to transmission facilities to justify the rate increase. The rate increase results from the reclassification of a significant portion of existing CVP facilities from the generation category to the transmission category. Western should limit the increase to 10 percent, which is supported by FERC precedent. Western should levelize the rate impact.

*Response:* Western reviewed the function of CVP facilities as part of the development of the transmission rate. Facilities that support the transfer capability of the transmission system were included in the transmission revenue requirement. Facilities that did not, such as generation tie lines and radial lines, were not included in the transmission revenue requirement. As a result of this review, there were only a few substations for which transmission costs were adjusted. The annual cost component for capital investment changed by less than $500,000 from the current transmission rates to the proposed transmission rates. The main reason for the increase in the CVP transmission rates is the increase in transmission O&M expenses. The transmission O&M expenses consist of O&M expenses directly charged to transmission facilities and non-direct charged O&M expenses. The non-direct charged O&M is allocated based on a ratio of transmission plant to total plant. This treatment of O&M expenses is consistent with utility industry standards and accepted by FERC. Increasing the rate by 10 percent or levelizing the rate is not consistent with a formula rate and would not meet the comparability standard set by FERC. A levelized rate would result in Western charging transmission customers less than what it charges itself for transmission service. Western believes the CVP transmission rate design meets the spirit and intent of FERC Order No. 888.

## Environmental Compliance

In compliance with the NEPA of 1969, 42 U.S.C. 4321, *et seq.*; Council on Environmental Quality Regulations, 40 CFR parts 1500–1508; and DOE NEPA Regulations, 10 CFR part 1021, Western determined this action is categorically excluded from the preparation of an environmental assessment or an environmental impact statement.

## Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866. This notice is not required to be cleared by the Office of Management and Budget.

## Regulatory Flexibility Analysis

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

## Small Business Regulatory Enforcement Fairness Act

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

## Availability of Information

Information about this rate adjustment, including PRS, comments, letters, memorandums, and other supporting material made or kept by Western used to develop the provisional rates, is available for public review. This information is in the Power Marketing Manager's office, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, California.

## Submission to the Federal Energy Regulatory Commission

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

## Order

In view of the foregoing and under the authority delegated to me by the Secretary of Energy, I confirm and approve on an interim basis, effective April 1, 2001, Rate Schedules CV–F10, CV–FT4, CV–NFT4, CV–TPT5, CV–NWT2, CV–RFS2, CV–EID2, CV–SPR2, CV–SUR2, CV–PSS2, CV–SCS1, COTP–FT2, and COTP–NFT2 for the Central Valley Project and for the California-Oregon Transmission Project, for the Western Area Power Administration. On April 10, 2001, by Amendment No. 4 to Delegation Order No. 0204–108, the Secretary of Energy delegated to Western's Administrator the authority to confirm, approve, and place into effect on an interim basis the rates in the Central Valley Project and California-Oregon Transmission Project-Rate Order No. WAPA–95. The rate schedules will remain in effect on an interim basis, pending FERC confirmation and approval of them or substitute rates on a final basis through December 31, 2004.

Dated: April 13, 2001.

Michael S. Hacskaylo,
*Administrator.*

## Rate Schedule CV–F10

*(Supersedes Schedule CV–F9)*

## Central Valley Project

## Schedule of Rates for Firm Power

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To the firm power customers for general power service.

*Character and Conditions of Service*

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

*Monthly Rates With Transmission Revenue Requirement Included*

| Period | Capacity | Energy |
|---|---|---|
| 04/01/01–09/30/01 | $3.44/kWmonth | 14.01 mills/kWh. |
| 10/01/01–09/30/02 | $3.73/kWmonth | 17.68 mills/kWh. |
| 10/01/02–09/30/03 | $3.89/kWmonth | 18.22 mills/kWh. |
| 10/01/03–09/30/04 | $3.86/kWmonth | 18.38 mills/kWh. |
| 10/01/04–12/31/04 | $3.80/kWmonth | 24.97 mills/kWh. |

The table below contains rates with the transmission revenue requirement removed from the firm power revenue requirement. These rates would apply if Western joins the California Independent System Operator (CAISO) or Regional Transmission Organization (RTO) and if the CAISO or RTO uses the transmission revenue requirement to develop a regional transmission rate.

*Monthly Rates With Transmission Revenue Requirement Removed*

| Period | Capacity | Energy |
|---|---|---|
| 04/01/01–09/30/01 | $2.55/kWmonth | 14.01 mills/kWh. |
| 10/01/01–09/30/02 | $2.91/kWmonth | 17.68 mills/kWh. |
| 10/01/02–09/30/03 | $3.08/kWmonth | 18.18 mills/kWh. |
| 10/01/03–09/30/04 | $3.05/kWmonth | 18.38 mills/kWh. |
| 10/01/04–12/31/04 | $2.92/kWmonth | 24.97 mills/kWh. |

*Pass Through of FERC–Accepted or –Approved Charges or Credits*

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by FERC, under which Western takes service, will be passed on to each appropriate customer. These FERC-accepted or -approved charges or credits are applicable to both sets of capacity and energy rates described above.

When possible, Western will pass through directly to the appropriate customer the FERC-accepted or -approved charges or credits in the same manner Western is charged or credited. If the FERC-accepted or -approved charges or credits cannot be passed through directly to the appropriate power customer, the charges or credits will be passed through using the CVP firm power rate design methodology. The rate design consists of the following allocation of costs. The capacity revenue requirement includes 100 percent of capacity purchase costs, 100 percent of CVP and COTP transmission expense, and 50 percent of the annual investment repayment, interest expense, and O&M expense allocated to power. These annual costs are reduced by the projected CVP and COTP transmission revenues and 50 percent of the projected CVP project use revenue to determine the capacity revenue requirement. The capacity revenue requirement for the rates that have the transmission revenue requirement removed is the same, except the CVP and COTP transmission expense and revenue are excluded from the calculation. The energy revenue requirement for both sets of proposed rates includes 100 percent of energy purchase costs and 50 percent of the annual investment repayment, interest expense, and O&M expense allocated to power. These annual costs are reduced by 50 percent of the projected project use revenues and the projected revenue from surplus power sales to determine the energy revenue requirement.

*Billing*

Demand: The rates listed above for capacity will be the charge per kilowatt (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.

*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, the overrun will be billed at 10 times the applicable rates above.

For Revenue Adjustment

The following method 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:

If ANR > PNR then 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:

If ANR < PNR and < 0 then 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:

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

Where:

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

If the actual net revenue is greater than the minimum investment payment, there is no surcharge.

3. The maximum RAC credit or surcharge is $20 million, $10 million for October through December 2004, plus the amount of purchase or exchange power contract adjustments used in recording associated expense.

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

5. For purposes of the RAC computation, the following terms are defined:

5.1 Actual Net Revenue—The recorded net revenue.

5.2 Annual Deficit—The amount of recorded annual expenses, including interest, exceeding recorded annual revenues.

5.3 Minimum Investment Payment—The lesser of 1 percent of the recorded unpaid investment balance at the end of the FY prior to the RAC calculation period, or the projected net revenue.

5.4 Projected Net Revenue—The annual net revenue available for investment repayment projected in the rate adjustment power repayment study (PRS) during the FY that RAC is being calculated (see Table 1).

5.5 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. For customers whose RAC credits cannot be fully credited through nine equal monthly amounts, Western may increase the RAC credit on the August and September power bills. For October 1 through December 31, 2004, see item 6 below.

5.6 RAC Calculation Period—The last recorded FY (October 1 through September 30). For October 1 through December 31, 2004, see item 6 below.

5.7 Recorded Net Revenue—The annual net revenue available for repayment recorded in the PRS for the FY the RAC is being calculated.

5.8 RAC will be calculated for FY 2001, even though the October 2000 to March 2001 portion of the FY is outside the rate case period. The revenues and expenses for FY 2001 will be used to determine the RAC for FY 2001.

6. A RAC will be calculated for October through December 2004. It will be allocated to each CVP firm power customer consistent with the procedure in item 4 above. The resulting RAC credit or surcharge will be applied to power bills issued from April to September 2005, if the customer has a power contract with Western during 2005. If the customer does not, Western will issue a bill or check for the October to December 2004 RAC surcharge or credit in April 2005.

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

| Period | Projected net revenue |
|---|---|
| October 1, 2000–September 30, 2001 | $4,923,466 |
| October 1, 2001–September 30, 2002 | 11,887,939 |
| October 1, 2002–September 30, 2003 | 10,426,583 |
| October 1, 2003–September 30, 2004 | 12,905,190 |
| October 1, 2004–December 31, 2004 | 1,737,596 |

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 stated in the contract.

For Power Factor Adjustment

The customer must maintain a power factor at all points of measurement between 95 percent lagging and 95 percent leading. The low power factor (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 in 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 ($/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 and below | 1.38 |

The rules and limitations of the LPF charge are as follows:

1. 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.

2. The measured on-peak power factor equals the power factor measured during the customer's maximum peak demand for each month, as recorded at the customer's point of delivery. If there are 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 the total information from the points of delivery. The monthly average and on-peak power factors are those recorded for CVP power only.

3. The upper limit for both the monthly average and measured on-peak power factors is 95 percent. Customers will receive no credit for operating between 100 percent and 95 percent power factors.

4. The LPF charge will apply to calculated power factors less than 95 percent, lagging or leading.

5. Customers with a monthly maximum peak demand less than or equal to 50 kW will not be subject to the LPF charge.

6. Western may waive the LPF charge for good cause in whole or in part.

**Rate Schedule CV–FT4**

*(Supersedes Schedule CV–FT3)*

**Schedule of Rate for Firm Transmission Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*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 receipt 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. It includes scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service.

*Formula Rate*

The formula rate for firm CVP transmission has two components.

Component 1 is the following formula:

$$\frac{TRR}{CVPc + TTc}$$

Where:

TRR = Transmission Revenue Requirement—the costs associated with facilities that support the transfer capability of the CVP transmission system, excluding generation facilities and radial lines. These costs include investment cost, interest expense, and operation and maintenance (O&M) expense, less revenue credits.

CVPc = CVP Capacity—the sum of the maximum operating capacity of the Northern CVP powerplants under normal operating conditions. Northern CVP powerplants are Judge Francis Carr, Folsom, Keswick, Nimbus, Shasta, Spring Creek, and Trinity.

TTc = Total Transmission Capacity—the total transmission capacity under long-term contract between Western and other parties.

Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CVP transmission service. The costs in component 2, and any changes to these costs, will be passed through to each appropriate transmission customer.

Western will revise the rate from component 1, as of April 30 of each year, based on previous year's annual financial data available. In addition to the annual update on April 30 of each year, Western will also revise the rate from component 1 if there is a change in the numerator or denominator that results in a rate change of at least $.05 per kilowattmonth. Customers will be notified of the rate change 30 days before the first bill is issued using the changed rates.

If the rates from the formula rate are higher than other transmission rates in California, transmission service for 1 year or less may be sold at a lower rate.

*Billing*

The rate from the formula rate listed above will be applied monthly to the maximum amount of capacity reserved, payable whether used or not.

*Adjustments*

For Losses

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

**Rate Schedule CV–NFT4**

*(Supersedes Schedule CV–NFT3)*

**Schedule of Rate for Nonfirm Transmission Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To nonfirm 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 three-phase alternating current at 60 hertz, delivered and metered at the voltages and points of delivery. It includes scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service.

*Formula Rate*

The formula rate for nonfirm CVP transmission has two components. Component 1 is the following formula:

$$\frac{TRR}{CVPe + TTe}$$

Where:

TRR = Transmission Revenue Requirement—the costs associated with facilities that support the transfer capability of the CVP transmission system, excluding generation facilities and radial lines. These costs include investment cost, interest expense, and operation and maintenance (O&M) expense, less revenue credits.

CVPe = CVP energy—the energy associated with the maximum operating capacity of the Northern CVP powerplants under normal operating conditions. Northern CVP powerplants are Judge Francis Carr, Folsom, Keswick, Nimbus, Shasta, Spring Creek, and Trinity.

TTe = Total Transmission energy—the energy associated with the total transmission capacity under long-term contract between Western and other parties.

Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CVP transmission service. The costs in component 2, as well as any changes to these costs, will be passed through to each appropriate transmission customer.

Western will revise the rate from component 1, as of April 30 of each year, based on previous year's annual financial data available. Western will also revise the rate from component 1 if there is a change in component 1 of the CVP firm transmission rate of at least $.05 per kilowattmonth. Customers will be notified of the rate change 30 days before the first bill is issued using the changed rates.

If the rates from the formula rate are higher than other transmission rates in

California, transmission service for 1 year or less may be sold at a lower rate.

*Billing*

The rate resulting from the formula rate listed above will be applied to each kWh delivered at the point of delivery, as specified in the service contract.

*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–TPT5**

*(Supersedes Schedule CV–TPT4)*

**Schedule of Rate for Transmission of CVP Power by Others**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*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.

*Formula Rate*

When Western incurs costs for using transmission facilities, other than its own, in supplying service under a customer's power sales contract, the customer will pay all costs, including transmission losses, incurred in the delivery of power. For billing purposes, transmission losses will be added to the meter readings of the capacity and energy delivered to the customer under the customer's power sales agreement with Western. For power deliveries under Contract No. 14–06–200–2948A (Contract 2948A) on the Pacific Gas and Electric Company's system, the transmission losses charged to the customer will be those losses that are in excess of the ''at or above 44-kilovolt'' transmission losses specified by Contract 2948A.

**Rate Schedule CV–NWT2**

*(Supersedes Schedule CV–NWT1)*

**Schedule of Rate for Network Integration Transmission Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers who receive network integration 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. It includes scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service.

*Formula Rate*

The formula rate for network transmission service consists of two components.

Component 1 is the product of the network customer's load ratio share times 1/12 of the annual network transmission revenue requirement. The load ratio share is the network customer's hourly load coincident with Western's monthly CVP transmission system peak, minus the coincident peak for all firm CVP (including reserved capacity) point-to-point transmission service, plus the reserved capacity of all firm point-to-point transmission service customers. The network transmission revenue requirement is the cost associated with facilities that support the transfer capability of the CVP transmission system, excluding generation facilities and radial lines.

Component 2 is for any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing network integration transmission service. The costs in component 2, as well as any changes to these costs, will be passed through to each appropriate transmission customer as part of the network integration transmission revenue requirement.

*Billing*

Billing determinants for the formula rate 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 as stated in the service agreement.

**Rate Schedule CV–RFS2**

*(Supersedes Schedule CV–RFS1)*

**Schedule of Rates for Regulation and Frequency Response Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers receiving regulation and frequency response service.

*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: $2.496 per kilowattmonth.
Weekly: $0.574 per kilowattweek.
Daily: $0.082 per kilowattday.

*Billing*

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

**Rate Schedule CV–EID2**

*(Supersedes Schedule CV–EID1)*

**Schedule of Rate for Energy Imbalance Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers receiving energy imbalance service.

*Character and Conditions of Service*

Energy imbalance service supplies 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.

*Formula Rate*

Within Limits of Deviation Band

Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations 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 firm power then in effect.

Outside Limits of Deviation Band

1. Positive Deviations—the greater of no charge, or any additional cost incurred.
2. Negative Deviations—during on-peak hours, the greater of three times the rate for CVP firm power or any additional cost incurred. During off-peak hours, the greater of the rate for CVP firm power or any additional cost incurred.

*Billing*

The billing determinants for the above formula rate will be specified in the service agreement.

**Rate Schedule CV–SPR2**

*(Supersedes Schedule CV–SPR1)*

**Schedule of Rates for Spinning Reserve Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers receiving spinning reserve service.

*Character and Conditions of Service*

Spinning reserve service supplies capacity that is available the first 10 minutes to take load and is synchronized with the power system.

*Rates*

Spinning Reserve Service Charge:
Monthly: $2.946 per kilowattmonth.
Weekly: $0.672 per kilowattweek.
Daily: $0.096 per kilowattday.
Hourly: $0.0040 per kilowatthour.

*Billing*

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

**Rate Schedule CV–SUR2**

*(Supersedes Schedule CV–SUR1)*

**Schedule of Rates for Supplemental Reserve Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers receiving supplemental reserve service.

*Character and Conditions of Service:*

Supplemental reserve service supplies capacity that is not synchronized with the power system but can be available to serve load within 10 minutes.

*Rates*

Supplemental Reserve Service Charge:
Monthly: $2.491 per kilowattmonth.
Weekly: $0.574 per kilowattweek.
Daily: $0.082 per kilowattday.
Hourly: $0.0034 per kilowatthour.

*Billing:*

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

**Rate Schedule CV–PSS2**

*(Supersedes Schedule CV–PSS1)*

**Schedule of Rate for Power Scheduling Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers receiving power scheduling service.

*Character and Conditions of Service*

Power scheduling service provides for the scheduling of resources to meet loads and reserve requirements.

*Rate*

$76.65 per hour.

*Billing*

The rate listed above will be applied as stated in the service agreement.

**Rate Schedule CV–SCS1**

**Schedule of Rate for Scheduling Coordinator Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To customers receiving scheduling coordinator service.

*Character and Conditions of Service*

Scheduling Coordinator service provides for the scheduling, real-time dispatching, and financial settlements with the California Independent System Operator and/or power exchanges.

*Rate*

$76.65 per hour.

*Billing*

The rate listed above will be applied as stated in the service agreement.

**Rate Schedule COTP–FT2**

*(Supersedes Schedule COTP–FT1)*

**Schedule of Rate for Firm Transmission Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*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 California-Oregon Transmission Project (COTP) at points of receipt with other systems and transmitted and delivered to points of delivery on the COTP 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. It includes scheduling, system control and dispatch service and reactive supply and voltage control service needed to support the transmission service.

*Formula Rate*

The formula rate for COTP firm transmission includes two components.

Component 1 is the following formula:

$$\frac{TRR}{COTPsc}$$

Where:

TRR = Transmission Revenue Requirement—Western's share of the costs associated with facilities that support the transfer capability of the COTP. These costs include investment cost, interest expense, operation and maintenance (O&M) expense, less revenue credits.

COTPsc = COTP seasonal capacity—Western's share of capacity under the then current California-Oregon Intertie transfer capability for the season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Western will update component 1 at least 15 days before the start of each season. Notification of rate changes will occur through the posting of the rate on the open access same time information system.

Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing COTP transmission service. The costs in component 2, as well as any changes to these costs, will be passed through to each appropriate transmission customer.

If the rates from the formula rate are higher than other transmission rates in California, transmission service for 1 year or less may be sold at a lower rate.

*Billing*

The rates listed above will be applied monthly to the maximum amount of capacity reserved, payable whether used 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–NFT2**

*(Supersedes Schedule COTP–NFT1)*

**Schedule of Rate for Nonfirm Transmission Service**

*Effective*

The first day of the first full billing period beginning on or after April 1, 2001, through December 31, 2004.

*Available*

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

*Applicable*

To nonfirm transmission service customers where power is received into the California-Oregon Transmission Project (COTP) 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 as agreed to by the parties.

*Character and Conditions of Service*

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

*Rate*

The formula rate for COTP nonfirm transmission includes two components.

Component 1 is the following formula:

$$\frac{TRR}{COTPe}$$

Where:

TRR = Transmission Revenue Requirement—Western's share of the costs associated with facilities that support the transfer capability of the COTP. These costs include investment cost, interest expense, operation and maintenance expense, less revenue credits.

COTPe = Energy associated with COTP Seasonal Capacity—the energy associated with Western's share of capacity under the then current California-Oregon Intertie (COI) transfer capability for the season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Western will update component 1 at least 15 days before the start of each season. Notification of rate changes will occur through the posting of the rate on the open access same time information system.

Component 2 is any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing COTP transmission service. The costs in component 2, as well as any changes to these costs, will be passed through to each appropriate transmission customer.

If the rates resulting from the formula rate are higher than other transmission rates in California, transmission service for 1 year or less may be sold at a lower rate.

*Billing*

The rates listed above will be applied to each kilowatthour delivered at the point of delivery, as specified in the service contract.

*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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