1998 Proposed Power, Transmission, and Ancillary Services Rates for Central Valley Project & California Oregon Transmission Project

Sierra Nevada Region

Western Area Power Administration

March 25, 1997

WESTERN AREA POWER ADMINISTRATION

Sierra Nevada Region

1998 Proposed Rate Adjustment Brochure

for

Proposed Rates for the Central Valley Project and the California-Oregon Transmission Project

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1. "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions", 10 CFR Part 903.

2. "CVP Contract Rates of Delivery", March 1, 1997.

3. Department of Energy Order RA6120.2, "Power Marketing Administration Financial Reporting".

SECTION I

Summary

This brochure provides information on the Western Area Power Administration (Western) proposed adjustment of the commercial firm power, power scheduling, transmission, and ancillary services rates for the Central Valley Project (CVP) and transmission service rates for the California-Oregon Transmission Project (COTP) effective October 1, 1997 through September 30, 2002.

A) *Proposed Rates for CVP Commercial Firm Power*

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

The present CVP commercial firm power rates were confirmed and approved by the Federal Energy Regulatory Commission (FERC) for the period October 1, 1995 through April 30, 1998, in a FERC Order issued March 14, 1996. Under Rate Schedule CV-F8 for the fiscal year (FY) 1998, the composite rate on October 1, 1997, is 26.50 mills per kilowatt-hour (mills/kWh), the base energy rate is 16.93 mills/kWh, the tier energy rate is 26.48 mills/kWh, and the capacity rate is $4.58 per kilowatt-month (kW-month).

The proposed rates for CVP commercial firm capacity and energy for the period October 1, 1997 through September 30, 2002 are shown in TABLE I-1.

TABLE I-1

Proposed CVP Commercial Firm Power Rates

Effective Period	Total Composite (mills/kWh)	Capacity ($/kW-month)	Energy (mills/kWh)	AERA (mills/kWh)
10/01/97 to 09/30/98	20.64	5.00	10.11	3.06
10/01/98 to 09/30/99	19.59	4.57	9.98	3.65
10/01/99 to 09/30/00	19.59	4.51	10.10	4.01
10/01/00 to 09/30/01	18.59	3.95	10.30	4.30
10/01/01 to 09/30/02	20.09	4.15	11.35	3.76

The proposed rates for CVP commercial firm power will result in an overall composite rate decrease of approximately 22 percent (%) on October 1, 1997, when compared to the FY 1998 commercial firm power rates under Rate Schedule CV-F8.

The proposed rates also include an Annual Energy Rate Alignment (AERA). The AERA will be an additional cost for firm energy purchases from Western at or above an average annual load factor of 80%. The AERA is the difference between the estimated market purchase rate in the rate adjustment for CVP commercial firm power and the proposed CVP energy rate. The AERA will be applied after the end of each fiscal year based on the customer's average annual load factor during the past fiscal year, and is in addition to the proposed CVP energy rates applied on a monthly basis.

The proposed rates listed above are based on the total CVP revenue requirement being allocated between capacity and energy in the following manner:

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

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

The resulting percentage splits of the capacity and energy revenue requirements for the proposed rates are as follow:.

Effective Period	Capacity %	Energy %
10/1/97 - 9/30/98	51	49
10/1/98 - 9/30/99	49	51
10/1/99 - 9/30/00	49	51
10/1/00 - 9/30/01	45	55
10/1/01 - 9/30/02	44	56

Power Factor Adjustment - The Low Power Factor Charge (LPF Charge) will be continued to encourage preference customers to monitor their power factors. Western proposes to continue the surcharge of $2.50 per reactive kilovolt-ampere (kVar) for any kVar produced because of a power factor less than 95%. The LPF Charge will be assessed on the average of the power factor measured at the time of the customer's peak demand and the customer's monthly average power factor. Both power factors will be for CVP power deliveries.

Low-voltage Adjustment - A 1.035 loss adjustment factor will be applied to the billed amounts for low-voltage CVP power deliveries on the Pacific Gas and Electric (PG&E) system.

Revenue Adjustment - The Revenue Adjustment Clause (RAC) tracks variances in future revenues and expenses, and lessens the probability of significant revenue surplus or deficit to the CVP repayment. The methodology for computing the RAC is a comparison of estimated total revenues less estimated total expenses to actual total revenues less actual total expenses. If the actual net revenue is more than the estimated net revenue, CVP preference customers receive a credit. If actual net revenue is less than the estimated net revenue, CVP preference customers may have a surcharge, if needed to make a minimum investment payment. The limit for surcharges is $20 million. The limit for credits is $20 million plus the amount of Energy Account No. 2 (EA2) credit or other purchase power contract adjustments used during the fiscal year for which the RAC is being calculated.

B) Proposed Rate for Power Scheduling Service

Power scheduling service provides for the scheduling of resources to meet load and reserve requirements. The proposed rate for power scheduling service is $73.80 per hour and is based on an estimated time to provide the service.

C) Proposed Rates for CVP Transmission

The proposed rate for firm CVP transmission service is $0.48 per kW-month, an 11.6% increase from the existing rate of $0.43 per kW-month currently under Rate Schedule CV-FT2. The proposed rate for non-firm CVP transmission service is 1.00 mill/kWh, an 18.7% reduction in the existing 1.23 mills/kWh rate. Service of firm or non-firm transmission for one year or less may be at rates lower than the proposed rates.

The proposed rates for CVP transmission service are based on a revenue requirement that recovers: (i) the CVP transmission system costs for facilities associated with providing all transmission service; and (ii) the non-facilities costs allocated to transmission service. These proposed firm and non-firm CVP transmission service rates include the cost for scheduling, system control and dispatch service, and reactive supply and voltage control services associated with the transmission service. The proposed rates are applicable to existing firm and non-firm CVP transmission services and future point-to-point transmission services. If scheduling, system control and dispatch service, and reactive supply and voltage control services are not provided by Western, the customers will be given a credit for the cost associated with these services.

D) Proposed Rate for Transmission of CVP Power by Others

Transmission service costs incurred by Western in the delivery of CVP power over a third party's transmission system to a CVP customer, will be directly passed through to that CVP customer. Rates under this schedule are proposed to be automatically adjusted as third party transmission costs are adjusted.

E) Proposed Rate for Network Transmission

The proposed rate for network transmission service, if offered by Western, is the product of the network customer's load ratio share times one twelfth (1/12) of the annual network transmission revenue requirement. The load ratio share is based on the network customer's hourly load coincident with Western's monthly CVP transmission system peak minus coincident peak for all firm CVP (including reserved capacity) point-to-point transmission service. The proposed rate for network transmission service is based on a revenue requirement that recovers: (i) the CVP transmission system costs for facilities associated with providing all transmission service; and (ii) the non-facilities costs allocated to transmission service. The proposed network transmission service rate includes the cost for scheduling, system control and dispatch service, and reactive supply and voltage control services associated with the transmission service. If scheduling, system control and dispatch service, and reactive supply and voltage control services are not provided by Western, the customers will be given a credit for the cost associated with these services.

F) Proposed Rates for COTP Transmission

The proposed rates for firm transmission service for Western's share of the COTP are $1.66 per kW-month for FY 1998 and $1.12 per kW-month for FY 1999 through FY 2002. These proposed rates for firm COTP transmission service result in 18.2% (FY 1998) and 44.8% (FY 1999 through FY 2002) reductions in the existing rate of $2.03 per kW-month. The proposed rates for non-firm COTP transmission service are 2.28 mills/kWh for FY 1998 and 1.54 mills/kWh for FY 1999 through FY 2002. These proposed rates for non-firm COTP transmission service result in 18.0% (FY 1998) and 44.6% (FY 1999 through FY 2002) reductions in the existing rate of 2.78 mills/kWh. Service of firm or non-firm transmission for one year or less may be at rates lower than the proposed rates.

The proposed rates for COTP transmission service are based on a revenue requirement that recovers the costs associated with: (i) Western's participation in the COTP; (ii) the offering of this service; and (iii) scheduling, system control and dispatch service, and reactive supply and voltage control services needed to provide the transmission service. The proposed rates are applicable to existing firm and non-firm COTP transmission services and future point-to-point transmission services. If scheduling, system control and dispatch service, and reactive supply and voltage control services are not provided by Western, the customers will be given a credit for the cost associated with these services.

G) Proposed Rates for Ancillary Services

The proposed rates for ancillary services, subject to the availability of the service, are designed to recover only the costs incurred by Western for providing the service(s) and are shown in TABLE I-2.

TABLE I-2

Proposed CVP Ancillary Services Rates

Ancillary Service Type	Proposed Rate
Transmission Scheduling, System Control and Dispatch Service -- is required to schedule the movement of power through, out of, within, or into a control area.	Included in appropriate transmission rates.
Reactive Supply and Voltage Control -- is reactive power support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.	Included in appropriate transmission rates.
Regulation and Frequency Response Service -- providing generation to match resources and loads on a real-time continuous basis.	Monthly: \$1.39 per kW-month. Weekly: \$0.3192 per kW-week. Daily: \$0.0456 per kW-day.
Energy Imbalance Service -- is provided when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month. Hourly Deviation (MW) is the net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.	<u>Within Limits of Deviation Band:</u> Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP commercial firm power, then in effect. <u>Outside Limits of Deviation Band:</u> (i) Positive Deviations - no charge, lost to the system. (ii) Negative Deviations - during *on-peak hours*, the greater of 3 times the proposed rates for CVP commercial firm power or any additional cost incurred. During *off-peak hours*, the greater of the proposed rates for CVP commercial firm power or any additional cost incurred.
Spinning Reserve Service -- is providing capacity that is available the first ten minutes to take load and is synchronized with the power system.	Monthly: \$1.14 per kW-month plus adder. Weekly: \$0.2688 per kW-week plus adder. Daily: \$0.0384 per kW-day plus adder. Hourly: \$0.0016 per kWh plus adder. Adder for purchasing energy to motor unit will be at market purchase rate.
Supplemental Reserve Service -- is providing capacity that is not synchronized, but can be available to serve loads within ten minutes.	Monthly: \$1.14 per kW-month. Weekly: \$0.2688 per kW-week. Daily: \$0.0384 per kW-day. Hourly: \$0.0016 per kWh.

The availability of the ancillary service will be determined at the time the service is requested. Sales of ancillary services of one year or less may be at rates lower that the proposed rates above.

SECTION II

Rate Adjustment Procedures

A) Public Process

The " Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions" (Procedures), 10 CFR Part 903, apply to this rate adjustment. A copy of the Procedures are available upon request. The first step required by the Procedures is the publication of a Federal Register notice (FRN). Western published the FRN (62 FR 9763) announcing the proposed rates and public consultation and comment period on March 4, 1997, and published a FRN (62 FR 1263) with correction to the "DATES" caption. The public consultation and comment period began on March 4, 1997, and ends on June 2, 1997. A copy of the FRN (62 F[illegible] [illegible]763) is included as APPENDIX A. TABLE II - 1 is a schedule of the major steps for the pro[illegible]sed rate adjustment proceedings.

TABLE II - 1

Schedule of Major Steps
Central Valley and California-Oregon Transmission Projects
Proposed Rate Adjustment Proceedings

Advance Announcement of Rate Adjustment	May 1, 1996
Informal Workshops	May 13, 1996 August 21, 1996 October 25, 1996 December 17, 1996
Federal Register Notice of Proposed Rates	March 4, 1997
Public Information Forum	March 25, 1997
Public Comment Forum	April 24, 1997
End of Consultation and Comment Period	June 2, 1997
Proposed Effective Date	October 1, 1997

B) Public Forums

A public information forum will be held on Tuesday, March 25, 1997, beginning at 9:00 a.m. PST, at the Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA. At the public information forum, representatives from Western will explain the proposed rate adjustment and will be available to answer questions. Questions not answered at the public information forum will be answered in writing by Western at least 15 days before the end of the consultation and comment period. The public information forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the company providing the service.

A public comment forum will be held to hear from interested persons on Thursday, April 24, 1997, beginning at 9:00 a.m. PDT, at the Sierra Nevada Region, Western Area Power Administration, located at the address provided above. Interested persons may submit written or oral comments. The public comment forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the company providing the service.

C) Written Comments

Interested persons may submit written comments to Western at any time during the consultation and comment period. Written comments should be submitted to:

Regional Manager
Western Area Power Administration
114 Parkshore Drive
Folsom, CA 95630-4710

Comments regarding the proposed rates <u>must</u> be received by the end of the public consultation and comment period, June 2, 1997.

D) Revisions of Proposed Rates

After the consultation and comment period is closes and consideration of oral and written comments is complete, Western may revise the proposed rates. If Western's Administrator determines that further public comment on any proposed rate should be invited, an extension of the consultation and comment period may take place, and one or more additional public forums may be held.

E) Decision on Proposed or Revised Proposed Rates

Following the end of the consultation and comment period, Western's Administrator may develop proposed rates, which the Deputy Secretary of the Department of Energy (DOE), may decide to confirm, approve, and place in effect on an interim basis as Provisional Rates. The decision by the Deputy Secretary of DOE, with an explanation of the principal factors leading to the decision, will be announced in a final FRN.

F) Final Decision on the Rate Adjustment

The Deputy Secretary of DOE will submit all the information concerning the Provisional Rates to FERC and request approval of the Provisional Rates for a five-year period. The FERC will then confirm and approve the Provisional Rates on a final basis; remand the Provisional Rates back to Western for further clarification and study; or, disapprove the Provisional Rates.

G) Additional Information

Additional information regarding the proposed rates or any questions regarding this brochure may be directed to Ms. Debbie Dietz, Rates Manager, Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630-4710, (916) 353-4453.

SECTION III

Central Valley Project Description

A) History and Description

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

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

In 1944, Congress authorized the American River Division to be constructed by the U.S. Army Corps of Engineers (Corps). In 1949, the Division was reauthorized for integration into the CVP. The Division included Folsom Dam and Powerplant, Nimbus Dam and Powerplant, and the Sly Park Unit, all located on the American River.

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

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

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

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

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

In 1964, Congress authorized the 500-kilovolt (kV) Pacific Northwest-Pacific Southwest Intertie (Intertie), of which Western has a 400 MW entitlement of transmission capacity to import power from the Pacific Northwest.

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

B) Integration With the Pacific Gas and Electric Company (PG&E)

PG&E and Western operate under Integration Contract No. 14-06-200-2948A (Contract 2948A), executed in 1967, which provides for the sale, interchange, and transmission of electric capacity and energy between Western and PG&E. Contract 2948A also includes provisions for the integration of power generated from the CVP facilities with the 400 MW of entitlement on the Intertie. The contract also provides that PG&E will support a maximum simultaneous demand of 1,152 MW for the CVP preference customers through calendar year 2004. If the CVP power

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C) CVP Power Allocations

Power generated from the CVP system is first dedicated to meeting the project pumping facilities' power requirements. The remaining power generated at the power facilities is allocated to various preference customers in California. The preference customers consist of the following:

1) Irrigation and water districts
2) Public utility districts
3) Municipalities
4) Federal agencies
5) State agencies
6) Rural electric cooperatives
7) Local and suburban passenger transportation entities
8) Joint power authorities

Each CVP preference customer's contract rate of delivery (CRD) is composed of firm long-term power allocations and may include short-term withdrawable allocations that are currently allocated, but unused by another customer. For this rate adjustment it is assumed that all customer withdrawable CRDs can be withdrawn in the event the load level of 1,152 MW is exceeded. The *CVP Contract Rates of Delivery* report, which lists CRDs as of March 1, 1997, is available upon request.

D) CVP Load Levels

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

SECTION IV

Central Valley Project Rate History

The first CVP power was produced at Shasta Powerplant. This power was sold to PG&E at a special rate averaging $10.00 per kilowatt-year (kW-year) and 1.5 mills/kWh. The term of the contract was from January 1, 1945 through December 31, 1947. It also included a provision that sales to PG&E could be withdrawn to meet CVP preference customer loads.

The first rate schedule for wholesale power service to CVP preference customers became effective March 6, 1945. Because a rate increase that was scheduled to become effective in 1974 was rescinded by a Federal court on procedural grounds, the rates remained virtually unchanged until May 25, 1978. Plant additions, increased replacements, and increased O&M expenses necessitated a series of rate increases. During that same time, costs for purchase power and wheeling also increased.

In 1983, the rates for CVP commercial firm power were approved by FERC for a five-year period. The rates at this time were designed to repay the annual expenses each year and to repay the deficit that had occurred from 1974 through 1983. The deficits were repaid in FY 1991.

FERC again approved CVP commercial firm power rates in 1988 for a five-year period. These rates included a Revenue Adjustment Clause (RAC) for the first time. The RAC allowed Western to automatically adjust for fluctuations in purchase power prices without getting FERC approval for new rates.

On September 22, 1993, FERC approved CVP commercial firm power rates for a five-year period from May 1, 1993 through April 30, 1998. These rates included an energy tier rate for energy sales at a 70% and higher monthly load factor, a ten times unauthorized overrun charge, a RAC modified to account for fluctuations in revenue for investment repayment, a peaking capacity rate, firm and non-firm CVP transmission service rates, and third-party transmission service at a passed through cost.

The existing Rate Schedule CV-F8 for CVP commercial firm power rates was approved by the Deputy Secretary of DOE and published in the Federal Register on October 10, 1995 (60 FRN 52671). FERC approval occurred on March 14, 1996, under FERC Docket No. EF95-5012-000 (74 FERC ¶ 62,136). These rates, shown below, were effective from October 1, 1995 through April 30, 1998.

Effective Period	Capacity Rate ($/kW-month)	Energy Rate (mills/kWh)	Tier Rate (mills/kWh)
10/1/95 - 9/30/96	4.03	14.83	25.90
10/1/96 - 9/30/97	4.32	15.93	26.27
10/1/97 - 4/30/98	4.58	16.93	26.48

TABLE IV-1 lists the historical rate schedules for the CVP.

TABLE IV-1

Chronology of CVP Rate Schedules
Commercial Firm Power

Effective Date	Capacity Rate (per kW-month)	Energy Rate (mills/kWh)
January 1, 1945	$10.00 per kW-year	1.5
March 6, 1945	$ 0.75	4, 3, 2
April 1, 1974	$ 1.15	3
June 1, 1976	--	--
May 25, 1978	$ 2.00	4.2
November 1, 1979	$ 2.00	5.11
May 25, 1983	$ 3.75	8.53
October 1, 1983	$ 3.75	13.74
October 1, 1984	$ 3.75	18.95
November 1, 1985	$ 3.75	27.97
October 1, 1986	$ 3.75	31.44
May 1, 1988	$ 6.86	14.43
October 1, 1989	$ 7.49	15.76
October 1, 1991	$ 7.74	16.30
May 1, 1993	$ 6.45	16.30
October 1, 1993	$ 6.22	17.97
May 1, 1994	$ 6.22	Base 16.99
		Tier 30.87
October 1, 1995	$ 4.03	Base 14.83
		Tier 25.90
October 1, 1996	$ 4.32	Base 15.93
		Tier 26.27

SECTION V

Central Valley Project Power Repayment Study

A) History

The historical costs and revenues from accounting records and the future projected costs are scheduled year-by-year in a Power Repayment Study (PRS). The PRS sets forth the level of future revenues required to repay all of the costs within the allowed time periods and within legislative requirements. The PRS does not set with the actual rate design, it merely determines the amounts to be repaid.

A PRS is prepared each year to test the adequacy of the existing rates. The annual update involves actual revenues and expenses for the previous year, plus new projections of revenues and expenses for the remainder of the repayment period. If the PRS demonstrates that repayment requirements will not be recovered or will be exceeded under the existing rates, Western prepares and recommends a plan to meet those repayment requirements. This plan is supported by a revised PRS and may include changing the power rates, decreasing costs, or modifying contracts.

The PRS Executive Summary prepared for the proposed rates can be found in APPENDIX B.

The PRS tracks three main categories of financial data; revenues, expenses, and investment repayment. CVP revenues are derived from commercial firm power sales, project use energy sales, transmission service, surplus power sales, ancillary services sales, and meter rentals. CVP expenses include O&M expense, purchase power, transmission service expenses, meter rental costs, and interest. CVP investments include original plant in service, replacements, and additions for hydroelectric generation, multipurpose, and transmission facilities, and irrigation aid.

The PRS begins in 1944 with the first generation of CVP power from Shasta Dam. The source documents for the historical revenues and expenses are the Western and Reclamation Financial statements (F/S). Repayment requirements are dictated by the authorizing act for power facilities, other applicable acts, and DOE policies, chiefly DOE Order RA6120.2, *Power Marketing Administration Financial Reporting* (RA6120.2). A copy of RA6120.2 is available on request.

A Western-wide audit of FY 1996 financial data, including the cost allocation and the PRS historical data has been completed. The audited amounts are used in the PRS, which will be part of the filing submitted to FERC.

B) Cost Allocation

Some of Western's power related costs, such as purchase power and transmission service expenses, are easily identified as costs to be included in the PRS. Other costs associated the CVP are not as evident, because the CVP is a Federal multipurpose reclamation project and is designed to serve many functions. Some of the functions are; river regulations, navigation, flood control, water supply, recreation, fish and wildlife habitat, and power generation. The CVP facilities providing such services are shared, necessitating an allocation of costs to determine the repayment responsibility of each function.

All O&M costs and the capital costs associated with the CVP are allocated by Reclamation. The costs included are from Western, Reclamation, and Corps projects that have been integrated with the CVP. A brief overview of Reclamation's allocation follows.

The Separable Cost-Remaining Benefit Method, recommended by the Interagency Committee on Water Resources in May 1950, is used as the basic cost allocation method. Some variations to the procedure have been used by Reclamation since 1968. These variations, approved by the Commissioner of Reclamation, involve combining some functions to form an initial allocation to water supply, total power, and recreation, fish and wildlife so that charges for use can more easily be accommodated.

The power related capital costs are first allocated to a total power function. These costs consist of all electric facilities costs plus an allocated portion of multipurpose joint costs. The total power costs are then suballocated between CVP commercial and CVP project use power in proportion to the projected usage of CVP resources and facilities by the commercial power users and project use customers. The commercial power costs are those repaid through Western's CVP commercial firm power rates.

C) Revenue Requirements

In general, revenue must be sufficient to recover the following expenses:

1. Annual O&M expense, purchase power and transmission service expenses, and interest on unamortized investment and deferred expenses.

2. After payment of annual expenses, deferred expenses (deficits) are repaid, starting with the highest interest-bearing deferred expense first.

3. After payment of annual expenses and deferred expenses, the Federal investment allocated or assigned to power users must be repaid within the allowable repayment period. Once again, the highest interest-bearing investment is repaid first.

D) Annual Revenues

TABLE V-1 provides the projected annual revenues for FY 1998 through FY 2002.

Project Use Power Revenues - Western and Reclamation have agreed to a flat amount of project use revenues of $9,360,000 per year. This revenue amount is then "trued-up" based on the actual O&M and transmission costs associated with delivering the actual project use power. The charges for project use power are collected by Reclamation through the CVP customers' water rates, and Reclamation transfers those revenues to Western.

CVP Commercial Firm Power Revenues- Estimated CVP commercial firm power revenues are derived by applying the proposed rates to the projected CVP commercial firm power sales. The forecast of revenues from commercial firm power sales is based on projected firm capacity and energy sales to the CVP preference customers. Revenues from other power sales are not included in the CVP commercial firm power revenues. The load forecast used in the PRS is contained in APPENDIX C. Total annual projected CVP commercial firm power sales used to determine the proposed rates are 6,900,169,636 kWh and 14,595,468 kilowatt (kW).

CVP Transmission Revenues - The projected CVP transmission service revenues assume that approximately 6,581,000 kW-month of CVP transmission capacity will be used on a firm basis to transmit non-CVP power over the CVP transmission system. The rate used in determining these revenues is the existing rate for firm CVP transmission service of $0.43 per kW-month.

Other Revenues - There are three sources of revenue included in this category, and are as follow:

1. Sales to PG&E - No sales into Energy Account No. 2 (EA2) are projected for FY 1998 through FY 2002.

2. Transmission of CVP Power by Others - All transmission service by others is directly passed through to Western's customers using this service. Both revenue and expenses at an average of $11 million per year are shown in the PRS to account for all charges, even though the net effect is zero. Transmission passed through revenues and expenses are estimated using existing customer load forecasts and project use requirements, and applicable transmission service rates. Transmission passed through revenues and expenses primarily consist of payments to PG&E for transmission service to preference and project use loads, and payments to Sacramento Municipal Utility District (SMUD) for transmission to preference customers. Existing rates for PG&E and SMUD transmission service are:

TABLE V-1

PROJECTED REVENUES

FISCAL YEAR	PROJECT USE	COMMERCIAL	TRANSMISSION	OTHER	TOTAL
1998	9,360,000	142,416,000	2,829,821	12,534,000	$167,139,821
1999	9,360,000	135,171,000	2,829,821	12,534,000	$159,894,821
2000	9,360,000	135,171,000	2,829,821	12,534,000	$159,894,821
2001	9,360,000	128,271,000	2,829,821	12,534,000	$152,994,821
2002	9,360,000	138,621,000	2,829,821	12,534,000	$163,344,821
AVERAGE	$9,360,000	$135,930,000	$2,829,821	$12,534,000	$160,653,821

Transmission Service Rates

PG&E	
Below 44-kV delivery	$5.063 per kW-month
Above 44-kV delivery	$1.141 per kW-month
Sonoma County	$3.97 per kW-month
SMUD	
Folsom Prison	$1.52 per kW-month
McClellan AFB	$1.20 per kW-month
(SMUD also applies a monthly surcharge)	

PG&E's existing transmission rates are approved through April 1, 2001. Western made no change in PG&E's transmission rates because no rate adjustment has been proposed by PG&E.

3. Miscellaneous Revenue - Western also receives revenues from customers amounting to approximately $1 million annually for services such as meter rentals, surplus power sales, and annual facility charges.

E) Annual Expenses

Annual expenses are the expenses that should be repaid in the year of occurrence under RA6120.2 procedures. Future expenses are forecasted by several methods, which are described below. TABLE V-2 shows the projected annual expenses for FY 1998 through FY 2002.

O&M Expense - The O&M expense originates from Western's latest projections and an escalation of Reclamation's FY 1996 O&M expense for the five fiscal years of the repayment period, and they are held constant thereafter. The O&M expense require a cost allocation to all CVP functions, and the annual amounts allocated to total power are incorporated in the PRS. O&M projections average $44 million per year for the rate adjustment period. An annual estimated cost of $3.5 million for the Shasta Rewinds Project is included in the projected O&M expense for FY 1998 through FY 2000.

Purchase Power Expenses - Western has a number of resource options at its disposal. The foundation of the CVP power resources is the generation from the hydroelectric facilities of the CVP. However, power generation from the CVP powerplants is not sufficient at all times to support the 1,152 megawatt (MW) maximum simultaneous peak demand, and is supplemented by other resources. These other resources are described below and they include purchases delivered over the Intertie and the COTP, and energy and capacity purchases from PG&E.

Purchase power expenses have decreased from previous years' levels, due to the reduction of

TABLE V-2

PROJECTED EXPENSES

FISCAL YEAR	O&M	PURCHASED POWER	OTHER	INTEREST	TOTAL
1998	42,767,929	93,542,000	15,091,000	$10,677,706	$162,078,635
1999	43,609,949	81,776,000	15,091,000	$10,493,281	$150,970,230
2000	44,840,625	78,086,000	15,091,000	$10,077,866	$148,095,491
2001	42,609,592	69,446,000	15,091,000	$9,447,850	$136,594,442
2002	43,918,051	67,839,000	15,091,000	$7,954,980	$134,803,031

customers' loads. The renegotiation and termination of several long-term firm purchase power contracts are also a major factor contributing to the reduction. However, it is still expected to be approximately 57% of the CVP's annual expenses over the next five-year period, and as such, are a major factor in the rate adjustment.

1. Capacity - The CVP provides 870 MW of Project Dependable Capacity (PDC) to support Western's 1,152 MW maximum simultaneous demand. PDC is a contractually negotiated amount agreed upon by PG&E and Western in accordance with Contract 2948A.

In addition to PDC from the CVP, Contract 2948A provides that Western can offset capacity purchases from PG&E with other resource purchases. Of the Northwest firm contract purchases, Western receives Northwest capacity credit for Portland General Electric (PGE) and PacifiCorp purchases. Capacity purchases are shown in TABLE V-3.

The July 31, 1995 agreement with PG&E sets a take or pay purchase of capacity based on a CVP simultaneous load level of 1,063 MW. The take or pay purchase of 50 MW is based on the CVP simultaneous load level of 1063 MW less the sum of PDC (870 MW) plus all Northwest capacity credits (143 MW). This purchase is at $5.875 per kW-month through December 31, 1999. Beginning January 1, 2000, a new rate will be calculated per the terms in the agreement with a 5% cap above and below the $5.875 per kW-month rate. If the simultaneous load level exceeds 1,063 MW, Western can make additional purchases at $6.76 per kW-month. For the proposed rates, the CVP simultaneous load level was assumed to be 1,063 MW in all years.

2. Energy - CVP power resources are dependent to a large extent on climactic conditions which affect both the supply of project water and the use of project power. Project operations for power generation are subordinate to water operations and environmental mitigation requirements. Power production in excess of project use requirements is available for sale as commercial power scheduled within water use limitations. The amounts of energy needed for project use limits the energy available for CVP commercial power customers.

For determination of the proposed rates, an average annual CVP generation, minus the energy required for project use pumping, is determined from a study that simulates the hydroelectric operation of the CVP with historical hydrologic data from 1922 to 1991. This study includes simulations of CVP generations in dry as well as above average hydrologic years.

Based on the above study, the CVP average annual generation is approximately 4,636 million kWh, adjusted for Trinity River restoration flow requirements and at load center value. About 1,193 million kWh per year is supplied to project use loads, and

TABLE V-3

COST OF PURCHASE POWER AND
SUMMARY OF CAPACITY PURCHASES BY SUPPLIER

	LONGVIEW	TACOMA	PORTLAND	PACIFICORP 63 MW	PACIFICORP 75 MW	PACIFICORP 7 MW	REDDING/ PACIFICORP LAYOFF	PG&E	TOTAL CAPACITY	TOTAL ENERGY & CAPACITY ($1,000)
CAPACITY IN MW										
1998	0	0	758	736	876	0	0	600	2,970	
1999	0	0	758	184	876	61	0	600	2,479	
2000	0	0	758	0	876	82	0	600	2,316	
2001	0	0	758	0	876	82	0	600	2,316	
2002	0	0	758	0	876	82	0	600	2,316	
CAPACITY RATES (In $ /MW-MO)										
1998	0.000	0.000	22.010	16.100	17.900	16.100	0.000	5.875		
1999	0.000	0.000	22.010	4.030	17.980	7.030	0.000	5.875		
2000	0.000	0.000	22.010	0.000	18.060	4.000	0.000	6.044		
2001	0.000	0.000	22.010	0.000	7.520	4.000	0.000	6.273		
2002	0.000	0.000	22.010	0.000	4.000	4.000	0.000	6.510		
COST OF PURCHASES (In $1,000)										
1998	0	0	16,692	11,841	15,678	0	0	3,525	47,736	93,542
1999	0	0	16,692	2,964	15,750	243	0	3,525	39,174	81,776
2000	0	0	16,692	0	15,822	324	0	3,626	36,464	78,086
2001	0	0	16,692	0	6,588	324	0	3,764	27,368	69,446
2002	0	0	16,692	0	3,504	324	0	3,906	24,426	67,839

approximately 3,443 million kWh per year is sold to the CVP preference customers. In order to support CVP preference customers' loads, about 3,525 million kWh per year must be purchased from other sources. An annual average of 1,609 million kWh per year from the Pacific Northwest and 1,916 million kWh from PG&E is purchased to meet this requirement.

Both CVP generation and preference customers loads change as seasonal climactic conditions vary throughout the year. Because of this, in any given month, CVP generation and purchased energy may or may not meet actual CVP preference customer energy demand. When energy supplies are not adequate, Western purchases energy from EA2, pursuant to Contract 2948A, to meet CVP preference customer power requirements.

3. Purchase Power - Western has firm purchase power contracts with Portland General Electric (PGE), PacifiCorp, and the City of Redding. The power from these entities supplements the CVP power resources in serving preference customer loads. The PGE contract expires on October 15, 2015; the PacifiCorp 100 MW contract was reduced to 63 MW and will be reduced to a 7 MW contract beginning 1/1/99, and expires on December 31, 2004; the PacifiCorp 75 MW contract expires on December 31, 2004; and the City of Redding contract expires on March 31, 1999. Previous contracts with the City of Tacoma and Longview Fibre Company have been, or are in the process of being terminated.

The projected rates and annual energy purchases in gigawatt-hours (GWh) at load center are shown in TABLE V-4.

4. Energy Account No.2 (EA2) - According to the contractual conditions under which this account was established, Western withdraws from EA2 at PG&E's average thermal energy rate, adjusted for a credit and a small service charge. Similarly, when supplies exceed actual CVP preference customer energy demand, Western sells energy into EA2. If EA2 sales are the result of surplus CVP hydropower generation, the rate for the sale is the CVP energy base rate. The rates for the sales from Northwest firm purchases are based on 85% of PG&E's annual thermal production rate, or Western's average Northwest purchase rate, whichever is lower. The estimated EA2 rate is derived by a model that estimates PG&E's average thermal energy costs and the EA2 production credit of prior purchases by PG&E. Western and PG&E entered into an agreement on February 7, 1992 that sets forth the methodology for determining PG&E's thermal costs.

In addition to the firm contracts listed above, market purchases of energy are projected for the five-year rate adjustment period. The rates for market purchases are based on average water year conditions and are escalated at 3.5% per year.

The rates and annual purchases (GWh) from EA2 purchases are shown in TABLE V-4.

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TABLE V-4

SUMMARY OF ENERGY PURCHASES BY SUPPLIER

	FIRM SUPPLIERS							NON FIRM SUPPLIERS	P G & E		TOTAL ENERGY PURCHASES	ENERGY ACCOUNT # 2		
	LONGVIEW	TACOMA	PORTLAND	PACIFICORP 63 MW	PACIFICORP 75 MW	PACIFICORP 7 MW	REDDING/ PACIFICORP LAYOFF		EA #2	OTHER		BALANCE START OF YEAR (GWh)	IN (GWh)	OUT (GWh)
ENERGY IN GWH														
1998	0	0	222	457	544	0	121	454	1,685	0	3,483	10,103	-	1,685
1999	0	0	222	135	544	36	36	679	1,830	0	3,482	8,418	-	1,830
2000	0	0	222	0	544	51	0	691	1,983	0	3,491	6,588	-	1,983
2001	0	0	222	0	544	51	0	712	2,020	0	3,549	4,605	-	2,020
2002	0	0	222	0	544	51	0	740	2,064	0	3,621	2,585	-	2,064
ENERGY RATES (In mills/kWh)														
1998	0.000	0.000	36.603	15.665	15.663	15.663	39.586	13.170	7.0100	0.00				
1999	0.000	0.000	37.715	15.690	15.878	15.173	39.706	13.630	7.2600	0.00				
2000	0.000	0.000	38.908	0.000	16.038	15.000	0.000	14.110	7.5100	0.00				
2001	0.000	0.000	40.155	0.000	13.768	15.000	0.000	14.600	7.7700	0.00				
2002	0.000	0.000	41.468	0.000	13.000	15.000	0.000	15.110	8.0400	0.00				
COST OF PURCHASES (In $1,000)														
1998	0	0	8,138	7,158	8,518	0	4,798	5,382	11,812	0	45,806			
1999	0	0	8,384	2,122	8,636	537	1,440	8,197	13,286	0	42,602			
2000	0	0	8,646	0	8,725	765	0	8,594	14,892	0	41,622			
2001	0	0	8,928	0	7,569	765	0	9,121	15,695	0	42,078			
2002	0	0	9,221	0	7,074	765	0	9,758	16,595	0	43,413			

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Other Expenses - Other expenses consist of primarily expenses from passed through transmission service by others. These expenses are forecasted by determining the future requirements, most of which are for transmission over the PG&E system. Additional information on passed through transmission expenses is contained in this section under "***D) Annual Revenues - Other Revenues***". Also included in the proposed rates are certain transmission expenses associated with the Intertie. Under a contract with the California Companies (PG&E, Southern California Edison and San Diego Gas and Electric) Western has a 400 MW entitlement to the Pacific Northwest-Pacific Southwest Intertie (Intertie) from Malin Substation to Tracy-Tesla Substation. Western pays the California Companies $3.35 per kW-year for transmission service on the Intertie, and pays PG&E to perform operation and maintenance on the part of the Intertie which Western owns. The California Companies in return pay Western for transmission over Western's share of the Intertie in an amount which will repay the cost of Western's share of the Intertie, with interest, over a fifty-year period.

F) Interest

Annual interest expense is determined by multiplying the various unpaid investments by the appropriate interest rate. A list of interest rates and the unpaid investment at the end of FY 1996 is as follows:

	Unpaid Investment ($)	Rate (%)
	62,575,000	0.000
	3,818,302	0.000
	74,302,348	3.000
	91,321,000	3.222
	28,944	5.500
	2,289	5.625
	45,881	6.125
	555	6.625
	12,328,230	7.000
	409,041	7.000
	245,767	7.250
	22,933,841	7.625
	4,705,000	7.625
	963,820	7.875
	1,228,257	8.000
	1,312,463	8.000
	12,929,321	8.500
Total	$ 289,150,059	

For the CVP, a 3.000% interest rate is applicable to all power investment authorized prior to, and including the San Luis Unit. The interest rate for the New Melones Project is 3.222% and is based on the interest formula in the Water Supply Act of 1958. RA6120.2 includes the criteria for setting interest rates to be applied to all new investments, additions, and replacements since October 1, 1983. The interest rate is equal to the average yield rate computed by the U.S. Department of the Treasury for the previous fiscal year. The applicable rate is for the year in which construction of the facilities is initiated.

G) Net Revenues

The revenues remaining after repayment of annual expenses will repay the remaining balance of the capitalized deficits first, if any, then the remaining balance of other power investment including Irrigation Aid will be paid. Deferring payment of annual expenses is allowed under RA6120.2 for short periods of time. For repayment purposes, when a deferral or a deficit occurs, it is assumed that a loan is taken out for the amount of the deficit. Then the initial loan, plus interest, must be repaid from future years' revenues. The applicable interest rate for deficits is also determined from the rate criteria of RA6120.2. Net revenue is applied to meet the repayment criteria of repaying the highest interest-bearing investment first, within allowable repayment periods.

A net revenue averaging $11 million per year for the entire repayment period will meet all required payments on the CVP investment. Based on the proposed rates, the net revenue for FY 1998 through FY 2002 averages $14 million per year. A higher annual net revenue is needed during the rate period and the years prior to FY 2014, due to a large payment on investment coming due in FY 2014. This is not based on amortization of the investment because a set amount is not repaid each year on a particular investment. Rather, a fairly constant flow of net revenue is projected throughout the repayment period to repay the costs at the lowest possible rates.

TABLE V-5 provides the projected net revenues for FY 1998 through FY 2002 at the proposed rates .

H) Investment

Original CVP plant investment and additions allocated to commercial power must be repaid with interest within fifty years after the related facility is placed in service. Replacements must be repaid within the estimated service life of each piece of equipment, or fifty years, whichever is shorter. Irrigation aid is to be repaid by FY 2030 without interest.

The CVP investment includes all CVP power costs allocated to the commercial power purpose and related facilities that are in place. The total CVP investment allocated to the commercial power function as of September 30, 1996 is $569 million. Irrigation aid is not included in this amount.

TABLE V-5

PROJECTED NET REVENUES

FISCAL YEAR	TOTAL REVENUES	TOTAL EXPENSES	NET REVENUES
1998	$167,139,821	$162,078,635	$5,061,186
1999	$159,894,821	$150,970,230	$8,924,591
2000	$159,894,821	$148,095,491	$11,799,330
2001	$152,994,821	$136,594,442	$16,400,379
2002	$163,344,821	$134,803,031	$28,541,790
AVERAGE	$160,653,821	$146,508,366	$14,145,455

The total CVP power investment through FY 2002 amounts to $675 million. Details of the investments follow.

Investments through FY 1996	$569 million
FY 1997 Additions & Replacements	20 million
FY 1998-FY 2002 Additions	6 million
FY 1998-FY 2002 Replacements	17 million
Irrigation Aid	63 million
Total	$675 million

Base Project - The $289 million for the Base Project includes the authorized CVP facilities through the San Luis Unit, and any additions through FY 1981. Changes should not occur in future years for this investment except for slight cost allocation adjustments caused by changes in use of the facilities. Most of this investment, $215 million, was repaid by FY 1973. The remaining balance is to be repaid with interest at 3.000% per year by FY 2014. The allowable repayment period is calculated as fifty years after the last major addition went into service in FY 1964.

New Melones- The New Melones Project investment through the end of FY 1996 is $91 million, and is included with additions, repayable at the authorized interest rate of 3.222%. New Melones became operable in 1981, and repayment is required fifty years later, in FY 2030.

Additions - Western began identifying other additions separate from the base project to comply with a September 1, 1982 letter from Western's Administrator. This letter states that current interest rates (in accordance with RA6120.2) should be used to compute interest on the unpaid balance of new facilities, additions, and replacements.

In 1982, new CVP facilities and replacements, with the exception of New Melones, were being identified, but additions were still included with the CVP Base Project costs which accrue interest at 3%. As there were no additions in FY 1982, the first CVP additions appear in the PRS in FY 1983.

Cumulative additions as of September 30, 1996 amount to $142 million. Future additions of $6 million are projected for FY 1998 through FY 2002, and tie in with programmed construction costs in the budget documents. After FY 2002, no future additions are assumed. A fifty-year repayment period is allowed for each addition.

Replacements - Prior to FY 1963, the CVP utilized a replacement reserve accounting method computed at 3% on a sinking fund basis. From FY 1963 through FY 1965, replacements were "expended" as they occurred. With the discontinuance of the replacement reserve, replacements were included as project investment until FY 1973. From FY 1973 and thereafter, replacement costs are separately identified in the PRS. The identified historical replacements as of September 30, 1996 equal $47 million.

Future replacements for the first five futures years of the PRS are taken from budget documents. Thereafter, the costs of the original facilities are indexed to current study year cost level, and replacements are forecasted to occur at the end of each facility's service life.

Replacements forecasted to occur from FY 1998 through FY 2002 amount to $17 million. Interest is computed on the forecasted replacements at 7.625%, the rate in effect for FY 1997.

Irrigation Aid - Irrigation Aid of $62.6 million is forecasted in the PRS, in FY 1997 and is held constant thereafter. The "Irrigation Aid" figure actually consists of two components, irrigation assistance and deferred use. Irrigation assistance is the revenue required from power to repay the irrigation investment that is beyond the ability of the irrigators to repay. Reclamation computes this amount as $5.7 million for existing plant-in-service facilities. Deferred use costs of $56.9 million are also included as costs to be recovered by the power users and treated identically to irrigation assistance. Deferred use costs are now projected as $2.4 million for excess capacity in the Folsom South Canal, and $54.5 million of excess capacity in the Tehama-Colusa Canal.

I) Current Repayment

CVP revenues were sufficient to repay the annual expenses and $215 million of investment through FY 1973. Deficits began to accrue beginning in FY 1974. Even though CVP commercial firm power rates were increased in May 1978 and November 1979, the revenue produced by those rate increases was still not sufficient to recover the annual expenses, and ultimately the deficits incurred by the CVP totaled $234 million. With the increase in rates beginning May 25, 1983, revenues were again sufficient to cover annual expenses in FY 1984. Payments on the deficit were made until FY 1991 when retirement of the deficit was complete.

From FY 1991 through FY 1996, revenues of $128 million were applied to repay investment, bringing the total investment repaid through FY 1996 to $343 million. This repayment is approximately 60% of the existing $569 million investment, with $226 million remaining to be repaid, excluding irrigation aid.

The following illustrates the current repayment of the CVP:

STATUS OF REPAYMENT AS OF 9/30/96

CVP Investment	(millions $)
Base Project	289
New Melones	91
Additions	142
Replacements	47
Total Investment	569
Cumulative Gross Revenues	3,851
Cumulative Expenses	3,508
Net Revenue Available	343
CVP Investment Remaining to Repay	226

SECTION VI

Proposed Rates for Central Valley Project Commercial Firm Power

A) Rate Design Methodology

Western's proposed rates for CVP commercial firm power reflect a capacity/energy revenue requirement split based on allocating the cost of the CVP power generation costs equally between capacity and energy, and allocating capacity purchase costs to capacity and energy purchase costs to energy. The proposed rates also include an Annual Energy Rate Alignment (AERA). The AERA will be applied at the end of each fiscal year to firm energy purchases from Western at or above an average annual load factor of 80%.

In order to utilize the CVP power resources to their maximum benefit, Western supports CVP generation with capacity and energy purchases, mainly from Northwest resources and PG&E. Western believes that all CVP customers benefit from this marketing approach and should pay for these benefits. The cost of the CVP power generation is split equally between the capacity and energy revenue requirements. The amount of capacity and energy available from the CVP hydroelectric system varies widely because of hydrologic conditions. These conditions can also impact the value of the capacity and energy. Due to this variability, Western is proposing an equal split between the capacity and energy revenue requirements for recovery of the cost of the CVP power generation.

Western's proposed rates for CVP commercial firm power is based on the following allocation of cost:

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

Based on estimates of the above expenses and revenues for the rate adjustment period, October 1, 1997 through September 30, 2002, the resulting percentage splits the capacity and energy revenue requirements used to determine the proposed rates are as follows:

Effective Period	Capacity %	Energy %
10/1/97 - 9/30/98	51	49
10/1/98 - 9/30/99	49	51
10/1/99 - 9/30/00	49	51
10/1/00 - 9/30/01	45	55
10/1/01 - 9/30/02	44	56

B) Proposed Annual Energy Rate Alignment (AERA)

The AERA will be an additional cost for firm energy purchases from Western at or above an average annual load factor of 80%. The AERA is the difference between the estimated market purchase rate in the rate adjustment for CVP commercial firm power and the proposed CVP energy rate, and as shown below.

Fiscal Year	Estimated Market Rate (mills/kWh)	CVP Commercial Firm Energy Rate (mills/kWh)	AERA
1998	13.17	10.11	3.06
1999	13.63	9.98	3.65
2000	14.11	10.10	4.01
2001	14.60	10.30	4.30
2002	15.11	11.35	3.76

The AERA provides risk mitigation for the market rate assumptions in the rate adjustment. If the estimated market rates are too low and customers increase their energy purchases from Western, then the AERA will provide additional revenues to cover the increased costs of serving the additional energy. The AERA will be applied after the end of each fiscal year based on the customer's average annual load factor for the past fiscal year. The AERA is in addition to the proposed CVP energy rates applied on a monthly basis. The proposed AERA supersedes the existing tier energy rates in Rate Schedule CV-F8. An example of AERA billing is shown below.

Example of AERA Billing

Average of monthly billed capacity purchased from Western during the fiscal year: 50 MW.

Total annual energy purchased from Western: 394,200,000 kWh.

Energy billed at AERA:

Energy at an 80% Load Factor:
50 MW X 8,760 hours X 0.80 = 350,400,000 kWh
394,200,000 kWh - 350,400,000 kWh = 43,800,000 kWh
43,800,000 kWh X 3.06 mills/kWh = $134,028

C) Proposed Rates for CVP Commercial Firm Power

The Deputy Secretary of the DOE, approved the existing Rate Schedule CV-F8 for CVP commercial firm power on September 19, 1995, and FERC confirmed and approved the rate schedule on March 14, 1996. The existing Rate Schedule CV-F8 is in effect from October 1, 1995, through April 30, 1998. Under Rate Schedule CV-F8, the composite rate on October 1, 1997, for FY 1998 is 26.50 mills/kWh, the base energy rate is 16.93 mills/kWh, the tier energy rate is 26.48 mills/kWh, and the capacity rate is $4.58 per kW-month. The proposed rates will replace the current rates in Rate Schedule CV-F8 and are scheduled to go in effect on October 1, 1997, to correspond with the start of the Federal fiscal year, and will remain in effect through September 30, 2002.

The proposed rates for CVP commercial firm power and the proposed AERA are shown in TABLE VI-1.

TABLE VI-1

Proposed CVP Commercial Firm Power Rates

Effective Period	Total Composite (mills/kWh)	Capacity ($/kW-month)	Energy (mills/kWh)	AERA (mills/kWh)
10/01/97 to 09/30/98	20.64	5.00	10.11	3.06
10/01/98 to 09/30/99	19.59	4.57	9.98	3.65
10/01/99 to 09/30/00	19.59	4.51	10.10	4.01
10/01/00 to 09/30/01	18.59	3.95	10.30	4.30
10/01/01 to 09/30/02	20.09	4.15	11.35	3.76

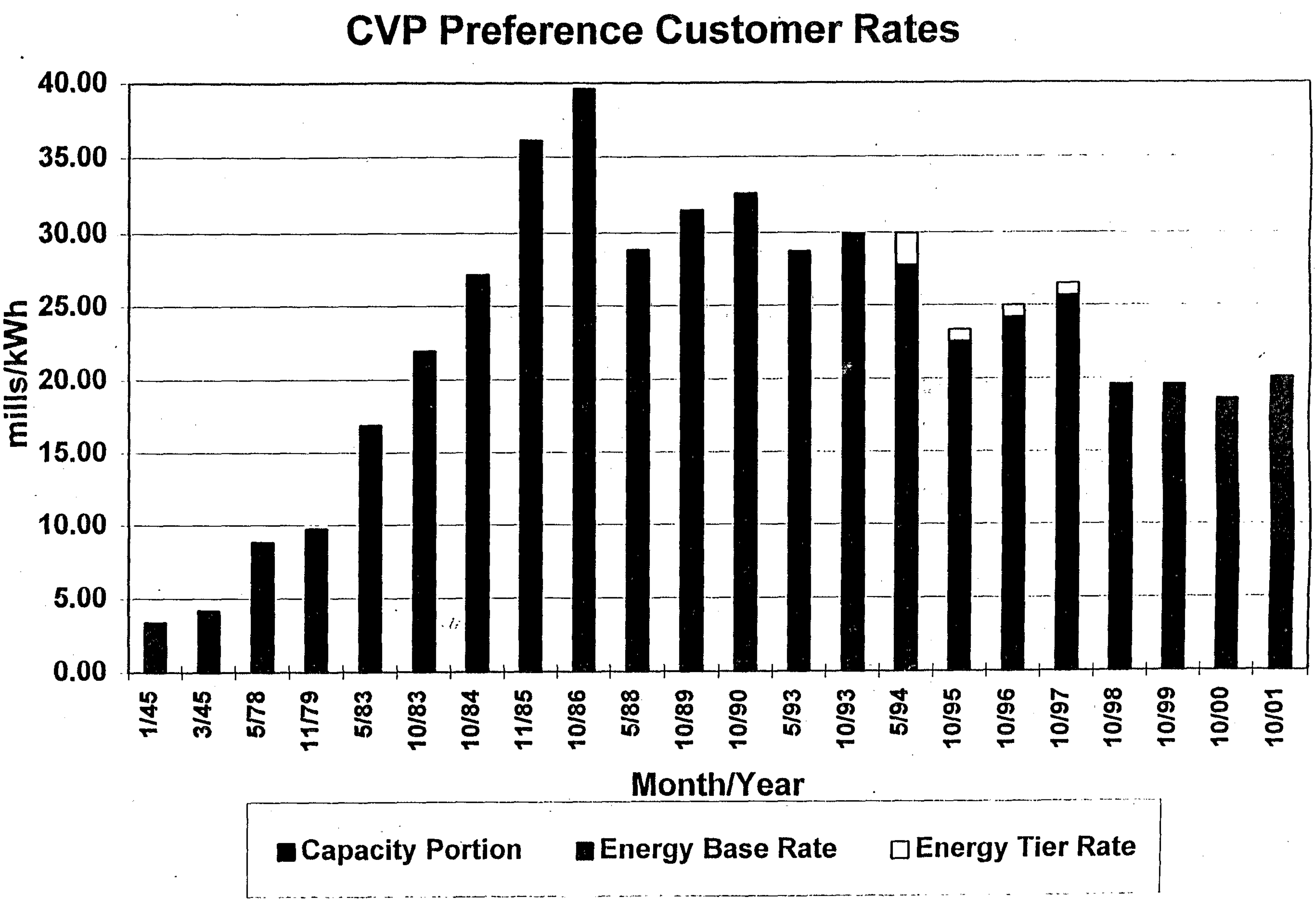
The proposed rates were developed based on the revenue requirements to meet all CVP repayment obligations, which are determined from the PRS. TABLE VI-2 provides an analysis of the development of the capacity and energy rates, and FIGURE VI-A compares the historical CVP commercial firm power rates with the proposed rates. The estimated sales shown in TABLE VI-2 slightly different than those shown in the load forecast in APPENDIX C. The energy purchase costs are slightly different than those shown in TABLE V-4.

TABLE VI-2

PROPOSED CAPACITY AND ENERGY RATE DEVELOPMENT

		1998	1999	2000	2001	2002
Capacity Revenue Requirement:						
Capacity Purchases	$	47,736,000	$39,174,000	$36,464,000	$27,368,000	$24,426,000
Fixed Transmission Expense	$	3,049,000	$ 3,049,000	$ 3,049,000	$ 3,049,000	$ 3,049,000
50% of CVP Power Generation Costs	$	25,003,411	$27,263,912	$29,108,912	$29,978,911	$35,957,412
Less CVP Transmission Revenues	$	(2,829,821)	$ (2,829,821)	$ (2,829,821)	$ (2,829,821)	$ (2,829,821)
TOTAL REVENUE REQUIREMENT	$	72,958,590	$66,657,091	$65,792,091	$57,566,090	$60,602,591
Estimated Annual Capacity Sales (kW-month)	$	14,592,000	$14,592,000	$14,592,000	$14,592,000	$14,592,000
RATE ($/kW-month)		**5.00**	**4.57**	**4.51**	**3.95**	**4.15**
Energy Revenue Requirement:						
Energy Purchases	$	45,789,000	$42,584,000	$41,603,000	$42,058,000	$43,392,000
50% of CVP Power Generation Costs	$	25,003,411	$27,263,912	$29,108,912	$29,978,911	$35,957,412
Less Excess Capacity Revenues	$	(1,000,000)	$ (1,000,000)	$ (1,000,000)	$ (1,000,000)	$ (1,000,000)
TOTAL REVENUE REQUIREMENT	$	69,792,411	$68,847,912	$69,711,912	$71,036,911	$78,349,412
Estimated Annual Energy Sales (MWh)	$	6,900,000	$ 6,900,000	$ 6,900,000	$ 6,900,000	$ 6,900,000
RATE (mills/kWh)		**10.11**	**9.98**	**10.10**	**10.30**	**11.35**

FIGURE VI-A


CVP Preference Customer Rates
mills/kWh
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1/45
3/45
5/78
11/79
5/83
10/83
10/84
11/85
10/86
5/88
10/89
10/90
5/93
10/93
5/94
10/95
10/96
10/97
10/98
10/99
10/00
10/01
Month/Year
Capacity Portion
Energy Base Rate
Energy Tier Rate

D) *Potential Impacts to Customers*

The proposed rates for CVP commercial firm power provide for a 22% decrease in the overall composite rate on October 1, 1997 when compared to the existing FY 1998 CVP commercial firm power rates in Rate Schedule CV-F8. On a composite rate basis, the proposed rates continue to decrease in four years of the five-year rate adjustment period. The renegotiations and termination of several long term firm purchase power contracts are the major factors contributing to this decrease.

The FY 1998 proposed composite rates are lower than the existing FY 1998 rates in Rate Schedule CV-F8, however the proposed capacity rate for FY 1998 is higher. This is due to the change in the methodology for splitting the revenue requirement between capacity and energy. In FY 1999, the capacity rate decreases by 9%, the energy rate decreases by 1%, and the overall composite rate decreases by 5% from the FY 1998 proposed rates.

While the composite rate in FY 2000 is the same as FY 1999, the capacity rate decreases by 1% (from $4.57 per kW-month to $4.51 per kW-month) and the energy rate increases by 1% (from 9.98 mills/kWh to 10.10 mills/kWh). The conflicting change in capacity and energy rates in FY 2000 is the result of the decrease in capacity purchase costs being larger than an increase in CVP power generation costs. However, the decrease in the energy purchase costs was not large enough to offset the increase in CVP power generation costs. The increase in CVP power generation costs is due to a higher annual investment payment and O&M expense. A similar situation occurs in FY 2001. The composite rate in FY 2001 decreases 5% (from 19.59 mills/kWh to 18.59 mills/kWh) from the composite rate in FY 2000. The FY 2001 capacity rate decreases by 12% (from $4.51 per kW-month to $3.95 per kW-month) and the energy rate increases by 2% (from 10.10 mills/kWh to 10.30 mills/kWh). The reason for this dichotomy is the same as for FY 2000, a large decrease in capacity purchase costs, and increases in energy purchase and CVP power generation costs. The increase in CVP power generation costs is due to an increase in the annual investment payment.

In FY 2002 the composite rate increases by 8% from the FY 2001 rate to 20.09 mills/kWh. Both capacity and energy rates increased from those in FY 2001. The FY 2002 capacity rate increases by 5% to $4.15 per kW-month and the energy rate increases by 10% to 11.35 mills/kWh. These increases in FY 2002 are due to an increased annual investment payment. A larger payment is needed to ensure repayment of investment due in FY 2014.

The impact of the AERA on the cost of energy purchases from Western, using FY 1998 proposed rates, ranges from negligible at an average annual load factor of 81% to nearly 5% at an average annual load factor of 95%.

E) Impacts of Proposed Rates to Existing Rates

The economic impact of the proposed rates for CVP commercial firm power when compared to the existing Rate Schedule CV-F8 rates at various customers' load factors is shown in TABLE VI-3. Based on the proposed rates for FY 1998, effective on October 1, 1997, a customer with a load factor of 40% would incur a cost decrease of approximately 16.5%. A customer with an 80% load factor would incur a cost decrease of approximately 28%. FIGURE VI-B shows the impact of the changes on customers at various load factors due to the proposed rates. The existing Rate Schedule CV-F8 rates for FY 1998 provide composite rates from 32.57 mills/kWh to 25.94 mills/kWh for load factors between 40 and 80%.

APPENDIX C details the projected CVP customers' load forecast for CVP customers for the rate adjustment period.

F) Power Factor Adjustment

History - In 1988, Western adopted a rate provision to encourage its customers to monitor poor power factors, to promote electric system efficiency, and to comply with Contract 2948A. Western encouraged its preference power customers to maintain at least a 95% power factor.

In 1988, the low power factor adjustment clause imposed a surcharge on a customer's total power costs based on the measured on-peak power factor. If the power factor measured on-peak is determined to be less than 95%, the surcharge provision is activated. This method of promoting improved power factors was only partially effective because it does not address off-peak power factors. A revised low power factor adjustment clause was implemented in 1993 to address the off-peak power factors.

Power Factor Charge - The proposed low power factor charge (LPF Charge) is the same as the existing LPF Charge in Rate Schedule CV-F8. The proposed LPF Charge will be applied when a preference customer does not maintain a 95% or greater power factor. Those operating below 95% will be charged for the additional kilovars (kVars), which would be required to raise the customer's power factor to 95%.

Calculations of the LPF Charge - The LPF Charge is calculated as follows:

LPF Charge = [(Peak Demand) * (kVar/kW Multiplier) * (kVar Rate)]

To determine the kVar/kW multiplier, a calculated power factor is developed. The calculated power factor is determined as follows:

Calculated Power Factor = [(Measured On-Peak Power Factor)
+ (Measured Monthly Power Factor)] / 2

TABLE VI-3

FY 1998
COMPARISON OF EXISTING RATES VS. PROPOSED RATES
MONTHLY COST FOR VARIOUS LOAD FACTORS

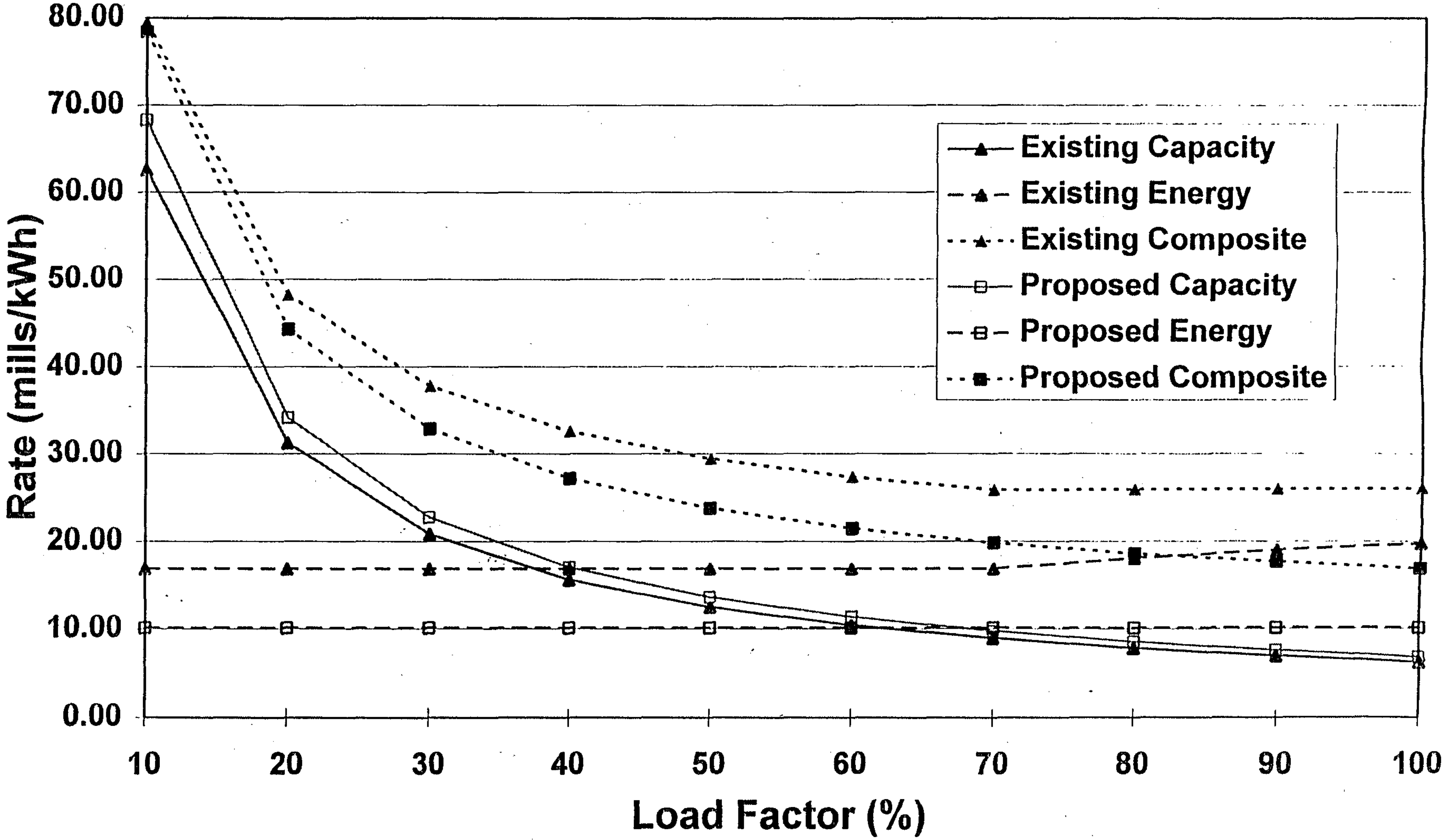
		EXISTING RATES	PROPOSED RATES				PROPOSED COMPOSITE RATES		
CUSTOMER LOAD FACTOR (%)	ESTIMATED CUSTOMER ENERGY (MWh)	TOTAL POWER BILL ($)	CAPACITY $5.00 kW-mo ($)	ENERGY 10.11 ($)	TOTAL POWER BILL ($)	CHANGE IN COST FROM EXISTING TO PROPOSED (%)	CAPACITY PORTION (mills/kWh)	ENERGY PORTION (mills/kWh)	TOTAL (mills/kWh)
10	732	$58,193	$50,000	$7,401	$57,401	(1.36)	68.31	10.11	78.42
20	1,464	$70,586	$50,000	$14,801	$64,801	(8.19)	34.15	10.11	44.26
30	2,196	$82,978	$50,000	$22,202	$72,202	(12.99)	22.77	10.11	32.88
40	2,928	$95,371	$50,000	$29,602	$79,602	(16.53)	17.08	10.11	27.19
50	3,660	$107,764	$50,000	$37,003	$87,003	(19.27)	13.66	10.11	23.77
60	4,392	$120,157	$50,000	$44,403	$94,403	(21.43)	11.38	10.11	21.49
70	5,124	$132,549	$50,000	$51,804	$101,804	(23.20)	9.76	10.11	19.87
80	5,856	$151,933	$50,000	$59,204	$109,204	(28.12)	8.54	10.11	18.65
90	6,588	$171,316	$50,000	$66,605	$116,605	(31.94)	7.59	10.11	17.70
100	7,320	$190,699	$50,000	$74,005	$124,005	(34.97)	6.83	10.11	16.94

NOTE: Calculations are for a 10 MW load; AERA excluded from these calculations.

FIGURE VI-B

Proposed Rate Design vs. Existing Rate Design

Rate Comparison at Various Load Factors (FY 1998)



The measured on-peak power factor is equal to the power factor measured during a customer's maximum peak demand for each month, as recorded at the customer's point of delivery. In the event of multiple occurrences of the same peak demand, the lowest associated power factor will be used. The measured monthly 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 on-peak and monthly average power factors are those recorded for CVP power only. The kVar rate represents the estimated cost of Western purchasing and installing equipment to increase a customer's power factor plus an additional charge to encourage customers to monitor poor power factors. The kVar rate is $2.50 per kVar.

The proposed kVar/kW multipliers are as follow:

Calculated Power Factor (%)	Proposed kVar/kW Multiplier
95	0
94	0.04088
93	0.06655
92	0.09733
91	0.12693
90	0.15564
89	0.18365
88	0.21106
87	0.23806
86	0.26463
85	0.29106
84	0.31726
83	0.34333
82	0.36932
81	0.39531
80	0.42132
79	0.44740
78	0.47360
77	0.49995
76	0.52648
75 and below	0.55323

Rules and Limitations of the Proposed LPF Charge - The rules and limitations of the proposed LPF Charge are as follow:

1. The upper limit for both the measured on-peak and monthly average power factors is 95%. No credit will be given for customers operating between 100 and 95% power factors for calculating the average power factors.

2. The calculated power factor will be rounded to the nearest whole percent, with 0.5% or greater rounded to the next higher percent.

3. The LPF Charge will be limited to charges based on a 75% or greater calculated power factor.

4. The LPF Charge will be applicable to calculated power factors less than 95%, leading or lagging.

5. Preference customers whose measured maximum peak demand is less than 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.

Additional detail on the development of the LPF Charge and examples of calculations for certain power factors are included in APPENDIX D.

Potential Impacts to Customers - Customers that do not maintain a 95% power factor on-peak and/or off-peak will be charged for any deviations. Under the proposed LPF Charge, a customer that is maintaining a 95% power factor on-peak, but not off-peak will incur a charge.

G) Possible Future Issues Impacting CVP Customers

Restructuring of the Electric Utility Industry - No assumptions were made regarding the restructuring in the development of the proposed rates. If, as a result of restructuring, Western makes significant changes in the way it conducts business, changes to the cost of service studies for CVP and COTP transmission service may be required, as well as the recovery of costs on the Intertie.

Legislation or Changes to Executive Orders - The proposed rates do not include any cost estimates that may be related to proposed legislation or changes to existing executive orders currently being considered, such as the sale of the Power Marketing Administrations (PMA), repayment reform, open transmission access, etc. Any legislation or change in existing executive orders concerning the PMAs and/or the way PMA business is conducted, could have a significant impact on future CVP rates.

Litigation - Western is currently in a lawsuit with the City of Tacoma regarding Western's purchase power contract. No costs are included in the proposed rates for litigation or any purchase of power from Tacoma.

Customer Funding of CVP O&M Expenses (O&M Funding Program) - The funding of O&M by preference power customers has no impact on the estimated costs used in developing the proposed rates. All O&M costs will be distributed through the proposed rates to all preference customers, regardless of their participation in the O&M Funding Program. Credits on power bills will offset contributions by participating customers. The overall level of costs may decrease due to savings realized as a result of the O&M Funding Program, or may increase depending on the level of funding approved by the Governance Board.

SECTION VII

Revenue Adjustment Clause

A) Methodology

A revenue adjustment clause (RAC) was first included in the CVP commercial firm power rate schedule in 1988 to provide greater stability in the repayment of the CVP investments and annual expenses. Western was concerned that fluctuation in its purchased power expenses would result in significant swings between an annual deficit or a surplus in the CVP repayment. Purchased power expenses at that time constituted almost 80% of the total annual CVP expenses.

The RAC methodology was revised in 1993. The revised methodology based the RAC on a comparison of the actual net revenue to the projected net revenue from the rate adjustment in the PRS. If the actual net revenue is greater than the projected net revenue, a revenue credit was distributed to the CVP commercial firm power customers. If the actual net revenue is less than the projected net revenue, a revenue surcharge may be distributed if needed to meet a minimum investment payment.

The RAC is calculated annually and the associated distribution of the RAC credit or surcharge occurs during a nine month period on power bills issued in the months of January through September. The annual limit was $20 million for a RAC credit or surcharge. Effective October 1, 1995, the RAC was amended to change the annual limit for RAC credits to $20 million plus the use of EA2 credit owed to Western by PG&E.

APPENDIX E contains specific details on the RAC methodology.

B) Proposed RAC

Western is proposing to continue the RAC methodology detailed in APPENDIX E, along with the current annual limits for RAC credits and surcharges. Western is also proposing to continue the distribution of the RAC for the nine month period from January to September.

C) Potential Impact to Customers

The potential impact to customers from the proposed RAC would be a possible RAC credit, up to $20 million plus the use of the EA2 credit, over the nine month period. A RAC credit or surcharge of $20 million, would result in an impact of about 3 mills/kWh decrease or increase to the proposed rates for CVP commercial firm power.

SECTION VIII

Proposed Rate for Power Scheduling Service

A) Proposed Rate for Power Scheduling Service

Power scheduling service provides for the scheduling of resources to meet loads and reserve requirements. The proposed rate for power scheduling service is $73.80 per hour and is based on an estimated time to provide the service.

B) Rate Methodology for Power Scheduling Service

The proposed rate for power scheduling service was designed to recover only the cost incurred by Western for providing the service. The proposed rate includes two cost components. The first cost component is the FY 1995 hourly cost for dispatcher and/or scheduler resources, escalated for the rate adjustment period of FY 1998 through FY 2002 to obtain an average hourly cost. The second cost component is an estimated hourly cost for phone system equipment necessary in providing the service.

A summary of the rate calculations are on page 33a. Additional detail on the development of the proposed rate for power scheduling service is included as APPENDIX F.

PROPOSED RATE FOR CVP POWER SCHEDULING SERVICE

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

Two Cost Components:

1. Hourly Cost for Dispatcher and/or Scheduler Resource:	$	68.00	per hour
2. Hourly Cost for Phone System Equipment:	$	5.80	per hour
Proposed Rate for Power Scheduling Service:	**$**	**73.80**	**per hour**

SECTION IX

Proposed Rates for CVP Transmission

A) Proposed Rates for CVP Transmission Service

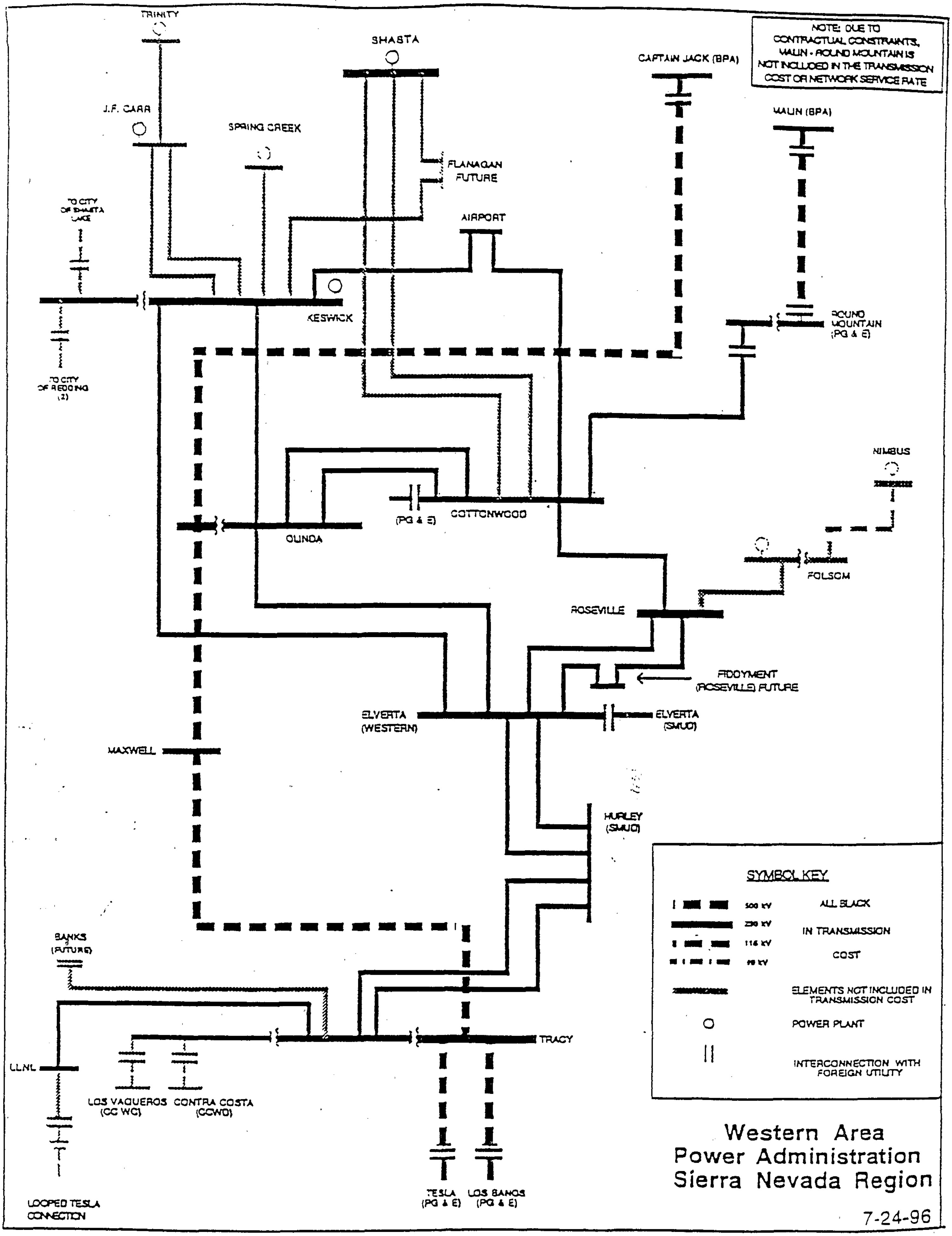
The proposed rate for firm CVP transmission service is $0.48 per kW-month, an 11.6% increase from the existing rate of $0.43 per kW-month currently under Rate Schedule CV-FT2. The proposed rate for non-firm CVP transmission service is 1.00 mill/kWh, an 18.7% reduction in the existing 1.23 mills/kWh rate. The proposed rate for firm CVP transmission is higher due to increases in transmission plant and charges in the basis for assigning miscellaneous and non-facility O&M costs to transmission. The proposed rate for non-firm CVP transmission is lower due to a change in the denominator, which is explained under the non-firm CVP transmission section in APPENDIX G. The rates for CVP transmission service for a period of one year or less may be lower than the proposed rates.

The proposed rates for firm and non-firm CVP transmission services will be used for existing CVP transmission services and future point-to-point transmission services when a party executes a contract with Western for the transmission of non-CVP power over the CVP transmission system. The proposed CVP transmission rates will be applied to the maximum transmission rate of delivery (TRD) provided for in a transmission service contract.

B) Rate Methodology for CVP Transmission Service

Western uses a detailed cost-of-service (COS) study to determine the revenue requirement that will be recovered from the CVP transmission service rates for firm and non-firm point-to-point transmission service. Each CVP transmission facility is researched in order to determine its functional use. Each facility is determined to be either a part of the transmission system, or is deemed to be a generation tie line or other system facility. A map detailing the CVP transmission system lines and substations is on page 34a. Only certain transmission system facilities or the commonly shared portion of the system facilities are considered in the determination of the CVP transmission rates. The rates also include the cost for scheduling, system control and dispatch service, and reactive supply and voltage control associated with the transmission service.

The COS study for the proposed rates was based on FY 1996 costs for O&M expense, administrative and general expenses, FY 1995 plant-in-service investment, projected investment, retirements, and replacements. Costs for projected investment were based on a five-year projection. These costs were then allotted to the facilities of the CVP transmission system that are considered to be available for transmission service and become the numerator in the rate calculation. Generation tie lines and interconnection facilities serving a specific customer were



NOTE: DUE TO CONTRACTUAL CONSTRAINTS, MALIN - ROUND MOUNTAIN IS NOT INCLUDED IN THE TRANSMISSION COST OR NETWORK SERVICE RATE
TRINITY
SHASTA
CAPTAIN JACK (BPA)
J.F. CARR
SPRING CREEK
FLANAGAN FUTURE
MALIN (BPA)
TO CITY OF SHASTA LAKE
AIRPORT
KESWICK
ROUND MOUNTAIN (PG & E)
TO CITY OF REDDING (2)
NIMBUS
(PG & E)
COTTONWOOD
OLINDA
FOLSOM
ROSEVILLE
FIDDYMENT (ROSEVILLE) FUTURE
ELVERTA (WESTERN)
ELVERTA (SMUD)
MAXWELL
HURLEY (SMUD)
SYMBOL KEY
500 kV
230 kV
115 kV
69 kV
ALL BLACK IN TRANSMISSION COST
ELEMENTS NOT INCLUDED IN TRANSMISSION COST
POWER PLANT
INTERCONNECTION WITH FOREIGN UTILITY
BANKS (FUTURE)
TRACY
LLNL
LOS VAQUEROS (CC WC)
CONTRA COSTA (CCWD)
TESLA (PG & E)
LOS BANOS (PG & E)
LOOPED TESLA CONNECTION
Western Area Power Administration Sierra Nevada Region
7-24-96

not included in the COS study.

After identifying the annual expenses related to the transmission system facilities, calculation of the denominator was determined. The COS study for the proposed CVP transmission rates took the sum of the CVP installed capacity for the northern plants (less station service) plus an average of the projected TRD under contract for the five-year rate adjustment period. The sum is the estimated number of kW to be delivered over the CVP transmission system for rate-making purposes. The annual expenses associated with the transmission system facilities are then divided by the total kW to arrive at the firm transmission rate and for existing CVP firm transmission service and future point-to-point transmission service.

The non-firm CVP transmission rate is calculated using the same costs as the firm rate calculation, but with an energy denominator. The non-firm rate denominator is the sum of the associated energy of the CVP northern plants (less station service) and the energy associated with the average projected TRD, both at 100% load factor.

A summary of the rate calculations are on page 35a. Additional detail on the development of the firm and non-firm point-to-point CVP transmission service rates is included as APPENDIX G.

C) Proposed Rate for Transmission of CVP Power by Others

Transmission service charges incurred by Western in the delivery of CVP power to a CVP preference customer over a third-party system will be directly passed through to the customer using the system. More information on passed through transmission costs is available under **SECTION V.**

D) Proposed Rate for Network Transmission Service

Network transmission service may be available under Western's tariff equivalent package (TEP). The TEP provides the terms for transmission access, consistent with FERC Order 888. The proposed rate for network transmission service, if offered by Western, is the product of the network customer's load ratio share times one-twelfth (1/12) of the annual network transmission revenue requirement. The load ratio share is based on the network customer's hourly load 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. The proposed rates for network transmission service is based on a revenue requirement that recovers the CVP transmission system costs for facilities associated with providing all transmission service and the non-facilities costs allocated to transmission service. These rates include the cost for scheduling, system control and dispatch service, and reactive supply and voltage control needed to provide the transmission service.

CVP TRANSMISSION PROPOSED RATES FOR EXISTING CONTRACTS AND POINT-TO-POINT SERVICE

	EXISTING	PROPOSED
Firm Rate	$0.43/kW-mo.	$0.48/kW-mo.
Cost of Service Study Monthly Cost	$801,306	$993,197
Denominator (kW-month)	1,869,000	2,050,370
Northern CVP Plants Capacity	1,353,000	1,404,500
Direct Service Customer Transmission	516,000	645,870
Energy Associated with Denominator (MWh)	653,843	1,496,770
Non-Firm Rate	1.23 mills/kWh	1.00 mills/kWh*

* Rate calculation is rounded up to 1 mill/kWh.

Sales of services for one year or less may be at rates lower than the proposed rates.

Rate includes costs for Transmission Scheduling, System Control, and Dispatch, and Reactive Supply and Voltage Control.

SECTION X

Proposed Rates for COTP Transmission

A) History

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

Currently, Western's participation on the COTP totals 266.4 MW which consists of an original 100 MW entitlement for use by the U.S. DOE, the Fish and Wildlife Service (F&WS), and other Federal uses, an additional purchase of 50 MW, and contractual layoffs totaling 116.4 MW. Western is terminating some of its contractual layoffs, which will reduce the capacity available in the five-year rate adjustment period.

B) Proposed Rates for COTP Transmission Service

The proposed rates for COTP transmission service are:

Effective 10/01/97 - 9/30/98:

Firm	$1.66 per kW-month
Non-Firm	2.28 mills/kWh

Effective 10/01/98 - 09/30/02:

Firm	$1.12 per kW-month
Non-Firm	1.54 mills/kWh

The proposed rates for firm COTP transmission service result in an 18.2% (FY 1998) and a 44.8% (FY 1999 through FY 2002) reduction in the existing rate of $2.03 per kW-month. The proposed rates for non-firm COTP transmission service result in an 18.0% (FY 1998) and a 44.6% (FY 1999 through FY 2002) reduction in the existing rate of 2.78 mills/kWh. The proposed rates are lower than the existing rates for COTP firm and non-firm transmission services as a result of reduced costs for and termination of some of Western's lease contracts for COTP transmission capacity. The rates for firm and non-firm COTP transmission service for a period of one year or less may be lower than the proposed rates.

The proposed rates for transmission service over the COTP will be used for existing service and future point-to-point service when a party executes a contract with Western for transmission service over the COTP transmission system. The proposed firm and non-firm COTP transmission service rates will be applied to the maximum TRD provided for in the transmission service contract.

C) Rate Methodology for COTP Transmission Service

The rate formula below is used to calculate the proposed rates for transmission service over the COTP transmission system;

> The rate is equal to the costs associated with providing the service divided by the available transmission capacity for the service.

The annual revenue requirement used to develop the numerator in the COTP transmission rate calculation are those costs associated with Western's long-term capacity rights, leased capacity, scheduling and facility charges, layoffs, and operation and maintenance for Western's use of 100 MW for DOE, F&WS, and other Federal uses. The denominator is the sum of the annual amount of available transmission capacity over the COTP system.

The non-firm rate is calculated using the same costs as the firm rate calculation, but with an energy denominator. The denominator used to calculate the non-firm rate is the sum of the associated annual energy amount of available transmission capacity over the COTP system at 100% load factor.

A summary of the rate calculations are on page 37a. Additional details on the development of the proposed firm and non-firm COTP transmission rates are included as APPENDIX H.

SECTION XI

Proposed Rates for Ancillary Services

A) Proposed Rates for Ancillary Services

Western is proposing rates for the six ancillary services available under Western's TEP and existing contracts. The TEP provides ancillary services consistent with FERC Order 888. Western's policy for the sales of ancillary services is as follows: (i) All sales are subject to the availability of the service(s); (ii) preference entities shall receive first priority for long term commitments; and (iii) regulation service and associated energy imbalance will be offered when required equipment is in place.

The proposed rates for ancillary services, subject to the availability of the service, are shown in TABLE XI-1.

COTP TRANSMISSION PROPOSED RATES FOR EXISTING CONTRACTS AND POINT-TO-POINT SERVICE

	EXISTING	PROPOSED 1998	PROPOSED 1999-2002
Firm Rate	$2.03/kW-mo.	$1.66/kW-mo.	$1.12/kW-mo.
Cost of Service Study Monthly Cost	$454,665	$346,203	$137,132
SNR Monthly Capacity (kW-month)	223,667	208,083	121,917
Energy Associated with SNR Monthly Capacity at 100% Load Factor (Mwh)	163,275	151,887	88,969
Non-Firm Rate	2.78 mills/kWh	2.28 mills/kWh	1.54 mills/kWh

Sales of services for one year or less may be at rates lower than the proposed rates. Rate includes costs for Transmission Scheduling, System Control, and Dispatch, and Reactive Supply and Voltage Control.

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TABLE XI-1

Proposed CVP Ancillary Services Rates

Ancillary Service Type	Rate
Transmission Scheduling, System Control and Dispatch Service -- is required to schedule the movement of power through, out of, within, or into a control area.	Included in appropriate transmission rates.
Reactive Supply and Voltage Control -- is reactive power support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.	Included in appropriate transmission rates.
Regulation and Frequency Response Service -- providing generation to match resources and loads on a real-time continuous basis.	Monthly: $1.39 per kW-month. Weekly: $0.3192 per kW-week. Daily: $0.0456 per kW-day.
Energy Imbalance Service -- is provided when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month. Hourly Deviation (MW) is the net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.	Within Limits of Deviation Band: Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP commercial firm power, then in effect. Outside Limits of Deviation Band: (i) Positive Deviations - no charge, lost to the system. (ii) Negative Deviations - during *on-peak hours*, the greater of 3 times the proposed rates for CVP commercial firm power or any additional cost incurred. During *off-peak hours*, the greater of the proposed rates for CVP commercial firm power or any additional cost incurred.
Spinning Reserve Service -- is providing capacity that is available the first ten minutes to take load and is synchronized with the power system.	Monthly: $1.14 per kW-month plus adder. Weekly: $0.2688 per kW-week plus adder. Daily: $0.0384 per kW-day plus adder. Hourly: $0.0016 per kWh plus adder. Adder for purchasing energy to motor unit will be at market purchase rate.
Supplemental Reserve Service -- is providing capacity that is not synchronized, but can be available to serve loads within ten minutes.	Monthly: $1.14 per kW-month. Weekly: $0.2688 per kW-week. Daily: $0.0384 per kW-day. Hourly: $0.0016 per kWh.

The proposed rates for ancillary services will be used when a party executes a contract with Western for providing the service(s). The contract will set forth the availability and terms and conditions of the ancillary service to be provided. The availability and type of ancillary service will be determined on a case-by-case basis. Contracts for ancillary services of one year or less may be at rates lower that the proposed rates set above.

B) Rate Methodology for Ancillary Services

The proposed rates for ancillary services were designed to recover only the cost incurred by Western for providing the service(s). The rate methodology for the proposed rates for transmission scheduling, system control and dispatch service, and reactive supply and voltage control are included in the methodology used in developing transmission service rates. The proposed rate for energy imbalance service was based on standards and practices used in the electric utility industry. For the proposed rates for regulation and frequency response, spinning reserve, and supplemental reserve services, Western used a detailed COS study to determine these rates, which are based on CVP facilities that are used in providing the service(s). Only those CVP facilities costs are considered in the determination of rates for regulation and frequency response, spinning reserve, and supplemental reserve services.

The COS study used in the development of the proposed rates for regulation and frequency response, spinning reserve, and supplemental reserve services determined two cost components. The first cost component is a monthly per kW cost based on FY 1995 costs for O&M expense and principle and interest payments on plant-in-service (PIS) investments for CVP facilities used in providing the service. The second cost component is a monthly per unit kW cost based on the estimated five-year average (FY 1998 - FY 2002) costs for dispatcher resources and any appropriate equipment necessary to provide the service. The two cost components were combined to develop the proposed rates.

The FY 1995 costs were escalated for the rate adjustment period of FY 1998 - FY 2002 to obtain average costs used in the determination of the two cost components. These average costs then become the numerator in the rate calculations.

The CVP facilities that are used in providing regulation and frequency response, spinning reserve, and supplemental reserve services are the Shasta, Folsom, Trinity, New Melones, Spring Creek, and Judge F. Carr powerplants. The maximum operating capability of these powerplants totals 1,706,000 kW and under adverse hydrological conditions with 90% exceedance probability, 60% of this total operating capability or 1,203,600 kW will be available to provide regulation and frequency response, spinning reserve, and supplemental reserve services. The Nimbus and Keswick powerplants are not available because of river run conditions. There are no governors at the O'Neill and San Luis powerplants, which makes them unavailable for providing the services. The capability of 1,203,600 kW became the denominator in the rate calculations.

A summary of the rate calculations for regulation and frequency response, spinning reserve, and supplemental reserve services are on pages 40a through 40c. Additional details on the development of the proposed rates for regulation and frequency response, spinning reserve, and supplemental reserve services are included as APPENDIX I.

PROPOSED RATE FOR CVP REGULATION SERVICE

Regulation Service is providing generation to match resources and loads on a real-time continuous basis.

Two Cost Components:

1.	Monthly Per Unit Cost for O&M, Interest, and Investment Divided by Capacity of Powerplants (90 % Exceedence) used to Provide Service.	$1.221 per kW-month
2.	Monthly Per Unit Cost for Dispatcher Resources and Control Area Equipment Services.	$0.165 per kW-month

Monthly CVP Regulation Service Rate	**$1.39 per kW-month**
Weekly CVP Regulation Service Rate	**$0.3192 per kW-week**
Daily CVP Regulation Service Rate	**$0.0456 per kW-day**

PROPOSED RATE FOR CVP SPINNING RESERVE SERVICE

Spinning Reserve is capacity that is available the first ten minutes to take load and is synchronized with the power system.

Three Cost Components:

1.	Monthly Per Unit Cost for O&M, Interest, and Investment Divided by Capacity of Powerplants (90 % Exceedence) used to Provide Service.	$1.10 per kW-month
2.	Monthly Per Unit Cost for SNR Dispatcher Resources.	$0.04 per kW-month
3.	Adder for purchasing energy to Motor Unit.	Market Rate

Monthly CVP Spinning Reserve Rate	**$1.14 per kW-month plus adder**
Weekly CVP Spinning Reserve Rate	**$0.2688 per kW-week plus adder**
Daily CVP Spinning Reserve Rate	**$0.0384 per kW-day plus adder**
Hourly CVP Spinning Reserve Rate	**$0.0016 per kW-hour plus adder**

PROPOSED RATE FOR CVP SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve is capacity that is not synchronized, but can be available to serve load within ten minutes.

Two Cost Components:

1.	Monthly Per Unit Cost for O&M, Interest, and Investment Divided by Capacity of Powerplants (90 % Exceedence) used to Provide Service.	$1.10 per kW-month
2.	Monthly Per Unit Cost for Dispatcher Resources.	$0.04 per kW-month

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Monthly CVP Supplemental Reserve Rate	**$1.14 per kW-month**
Weekly CVP Supplemental Reserve Rate	**$0.2688 per kW-week**
Daily CVP Supplemental Reserve Rate	**$0.0384 per kW-day**
Hourly CVP Supplemental Reserve Rate	**$0.0016 per kW-hour**

APPENDIX A

Federal Register Notice 62 FR 9763

and

Federal Register Notice 62 FR 1263

Western Area Power Administration; Proposed Rates for Central Valley and California-Oregon Transmission Project

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed rates.

SUMMARY: The Western Area Power Administration (Western) is proposing rates (Proposed Rates) for Central Valley Project (CVP) commercial firm power, power scheduling service, CVP transmission, transmission of CVP power by others, network transmission, California-Oregon Transmission Project (COTP) transmission, and ancillary services. The current rates expire April 30, 1998. The Proposed Rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period. The rate impacts are detailed in a rate brochure to be provided to all interested parties. The Proposed Rates are scheduled to go into effect on October 1, 1997, to correspond with the start of the Federal fiscal year, and will remain in effect through September 30, 2002. This Federal Register notice initiates the formal process for the Proposed Rates.

DATES: The consultation and comment period will begin from the date of publication of this Federal Register notice and will end June 2, 1997. A public information forum at which Western will present a detailed explanation of the Proposed Rates is scheduled for March 25, 1997, beginning at 9 a.m. PST, at the Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710. A public comment forum at which Western will receive oral and written comments is scheduled for April 2~~2~~4, 1997, beginning at 9 a.m. PDT, at the same location. Western should receive written comments by the end of the consultation and comment period to be assured consideration.

ADDRESSES: Written comments are to be sent to: James C. Feider, Regional Manager, Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710.

FOR FURTHER INFORMATION CONTACT: Debbie Dietz, Rates Manager, Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4453.

SUPPLEMENTARY INFORMATION: The Proposed Rates for CVP commercial firm power are designed to recover an annual revenue requirement that includes the investment repayment, interest, purchase power, and operation and maintenance expense. A cost of service study allocates the projected annual revenue requirement for commercial firm power between capacity and energy. The capacity revenue requirement includes 100 percent of capacity purchase costs, 50 percent of the investment repayment, interest expense, and power operation and maintenance expense allocated to commercial power, and 100 percent of fixed transmission expense. These annual costs are reduced by the projected revenue from sales of CVP transmission to determine the capacity revenue requirement. The energy revenue requirement includes 100 percent of energy purchase costs and 50 percent of the investment repayment, interest expense, and power operation and maintenance expense allocated to commercial power. These annual costs are reduced by the projected revenue from sales of surplus power to determine the energy revenue requirement. The resulting capacity/energy revenue requirement split varies from 51 percent allocated to capacity in fiscal year (FY) 1998 to 44 percent allocated to capacity in FY 2002. The average capacity/energy revenue requirement split for the five-year period is 47 percent to capacity and 53 percent to energy.

The Proposed Rates will also include an Annual Energy Rate Alignment (AERA). The AERA will be applied to firm energy purchases from Western at or above an average annual load factor of 80 percent. The AERA is the difference between the estimated market purchase rate used in the cost of service study for CVP commercial firm power and the CVP energy rate. The billing for the AERA will occur at the end of each fiscal year.

The Proposed Rates for CVP commercial firm power, applicable revenue requirement split between capacity and energy, and the AERA are provided in Table 1 below.

TABLE 1.—PROPOSED COMMERCIAL FIRM POWER RATES

Effective period	Total composte (mills/kWh)	Capacity ($/kW-mo)	Energy (mills/kWh)	Capacity/energy split	AERA (mills/kWh)
10/01/97 to 09/30/98	20.64	5.00	10.11	51/49	3.06
10/01/98 to 09/30/99	19.59	4.57	9.98	49/51	3.65
10/01/99 to 09/30/00	19.59	4.51	10.10	49/51	4.01
10/01/00 to 09/30/01	18.59	3.95	10.30	45/55	4.30
10/01/01 to 09/30/02	20.09	4.15	11.35	44/56	3.76

The Deputy Secretary of the Department of Energy (DOE), approved the existing Rate Schedule CV–F8 for CVP commercial firm power on September 19, 1995 (Rate Order No. WAPA–72, 60 FR 52671, October 10, 1995), and the Federal Energy Regulatory Commission (FERC) confirmed and approved the rate schedule on March 14, 1996, under FERC Docket No. EF95–5012–000 (74 FERC ¶ 62,136). The existing Rate Schedule CV–F8 became effective on October 1, 1995, for the period ending April 30, 1998. Under Rate Schedule CV–F8, the composite rate on October 1, 1997, is 26.50 mills per kilowatt-hour (mills/kWh), the base energy rate is 16.93 mills/kWh, the tier energy rate is 26.48 mills/kWh, and the capacity rate is $4.58 per kilowatt-month (kW-mo). The Proposed Rates for CVP commercial firm power will result in an overall composite rate decrease of approximately 22 percent on October 1, 1997, when compared with the current CVP commercial firm power rates under Rate Schedule CV–F8. Table 2 provides a comparison of the current rates in Rate Schedule CV–F8 and the Proposed Rates along with the percentage change in the rates.

TABLE 2.—COMPARISON OF CURRENT AND PROPOSED RATES
[Percentage Change in Commercial Firm Power Rates]

Effective period	Total composite (mills/kWh)	Percent change	Capacity ($/kW-mo)	Percent change	Base energy (mills/kWh)	Percent change
Current Rate Schedule						
Existing 10/01/97 and thereafter	26.50	....	4.58	....	16.93	....
Proposed Rates						
10/01/97 to 09/30/98	20.64	−22	5.00	+9	10.11	−40
10/01/98 to 09/30/99	19.59	−26	4.57	....	9.98	−41
10/01/99 to 09/30/00	19.59	−26	4.51	−2	10.10	−40
10/01/00 to 09/30/01	18.59	−30	3.95	−14	10.30	−39
10/01/01 to 09/30/02	20.09	−24	4.15	−9	11.35	−33

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

Power Factor Adjustment

This provision contained in Rate Schedule CV–F8, will remain the same under the Proposed Rates for CVP commercial firm power.

Low Voltage Loss Adjustment

This provision contained in Rate Schedule CV–F8, will remain the same under the Proposed Rates for CVP commercial firm power.

Revenue Adjustment

The methodology for the Revenue Adjustment contained in Rate Schedule CV–F8, will remain the same under the Proposed Rates for CVP commercial firm power.

Proposed Rate for Power Scheduling Service

The Proposed Rate for power heduling service is $73.80 per hour ınd is based on an estimated time to provide the service. Power scheduling service provides for the scheduling of resources to meet loads and reserve requirements.

Proposed Rates for CVP Transmission

The Proposed Rate for firm CVP transmission service is $0.48 per kW-mo., an 11.6 percent increase from the existing rate of $0.43 per kW-mo. currently under Rate Schedule CV-FT2. The Proposed Rate for non-firm CVP transmission service is 1.00 mill/kWh, an 18.7 percent reduction in the existing 1.23 mills/kWh rate. Service of firm or non-firm transmission for one year or less may be at rates lower than the Proposed Rates.

The Proposed Rates for CVP transmission service are based on a revenue requirement that recovers: (i) The CVP transmission system costs for facilities associated with providing all transmission service; and (ii) the non-facilities costs allocated to transmission service. These rates include the cost for scheduling, system control and dispatch service, and reactive supply and voltage control associated with the transmission service. The Proposed Rates are applicable to existing CVP firm transmission service and future point-to-point transmission service.

Proposed Rate for Transmission of CVP Power by Others

Transmission service costs incurred by Western in the delivery of CVP power over a third party's transmission system to a CVP customer, will be directly passed through to that CVP customer. Rates under this schedule are proposed to be automatically adjusted as third party transmission costs are adjusted.

Proposed Rate for Network Transmission

The Proposed Rate for network transmission service, if offered by Western, is the product of the network customer's load ratio share times one-twelfth (1/12) of the annual network transmission revenue requirement. The load ratio share is based on the network customer's hourly load coincident with Western's monthly CVP transmission system peak minus coincident peak for all firm CVP (including reserved capacity) point-to-point transmission service. The Proposed Rate for network transmission service is based on a revenue requirement that recovers: (i) The CVP transmission system costs for facilities associated with providing all transmission service; and (ii) the non-facilities costs allocated to transmission service. These rates include the cost for scheduling, system control and dispatch service, and reactive supply and voltage control needed to provide the transmission service.

Proposed Rates for COTP Transmission

The Proposed Rates for firm transmission service for Western's share of the California-Oregon Transmission Project (COTP) are $1.66 per kW-mo. for FY 1998 and $1.12 per kW-mo. for FY 1999 through FY 2002. These Proposed Rates for firm COTP transmission service result in 18.2 percent (FY 1998) and 44.8 percent (FY 1999 through FY 2002) reductions in the existing rate of $2.03 per kW-mo. The Proposed Rates for non-firm COTP transmission service are 2.28 mills/kWh for FY 1998 and 1.54 mills/kWh for FY 1999 through FY 2002. These Proposed Rates for non-firm COTP transmission service result in 18.0 percent (FY 1998) and 44.6 percent (FY 1999 through FY 2002) reductions in the existing rate of 2.78 mills/kWh. Service of firm or non-firm transmission for one year or less may be at rates lower than the Proposed Rates.

The Proposed Rates for COTP transmission service are based on a revenue requirement that recovers the costs associated with: (i) Western's participation in the COTP; (ii) the offering of this service; and (iii) scheduling, system control and dispatch service, and reactive supply and voltage control needed to provide the transmission service. The Proposed Rates are applicable to existing COTP transmission service and future point-to-point transmission service.

Proposed Rates for Ancillary Services

Western will provide ancillary services, subject to availability, at the Proposed Rates listed in Table 3. The Proposed Rates are designed to recover only the costs incurred by Western for providing the service(s). Sales of ancillary services of one year or less may be at rates lower than the Proposed Rates.

TABLE 3.—PROPOSED CVP ANCILLARY SERVICES RATES

Ancillary service type	Rate
Transmission Scheduling, System Control and Dispatch Service—is required to schedule the movement of power through, out of, within, or into a control area	Included in appropriate transmission rates.
Reactive Supply and Voltage Control—is reactive power support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system	Included in appropriate transmission rates.
Regulation and Frequency Response Service—providing generation to match resources and loads on a real-time continuous basis.	Monthly: $1.39 per kW-mo. Weekly: $0.3192 per kW-week. Daily: $0.0456 per kW-day.
Energy Imbalance Service—is provided when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month	Within Limits of Deviation Band: Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP commercial firm power, then in effect.
Hourly Deviation (MW) is the net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.	Outside Limits of Deviation Band: (i) Positive Deviations—no charge, lost to the system. (ii) Negative Deviations—during on-peak hours, the greater of 3 times the Proposed Rates for CVP commercial firm power or any additional cost incurred. During off-peak hours, the greater of the Proposed Rates for CVP commercial firm power or any additional cost incurred.
Spinning Reserve Service—is providing capacity that is available the first ten minutes to take load and is synchronized with the power system	Monthly: $1.14 per kW-mo. plus adder. Weekly: $0.2688 per kW-wk. plus adder. Daily: $0.0384 per kW-day plus adder. Hourly: $0.0016 per kWh plus adder. Adder for purchasing energy to motor unit will be at market purchase rate.

TABLE 3.—PROPOSED CVP ANCILLARY SERVICES RATES—Continued

Ancillary service type	Rate
Supplemental Reserve Service—is providing capacity that is not synchronized, but can be available to serve loads within ten minutes	Monthly: $1.14 per kW-mo. Weekly: $0.2688 per kW-wk. Daily: $0.0384 per kW-day. Hourly: $0.0016 per kWh.

Since the Proposed Rates constitute a major rate adjustment as defined by the procedures for public participation in general rate adjustments, as cited below, both a public information forum and a public comment forum will be held. After review of public comments, Western will recommend the Proposed Rates (and as amended) for approval on an interim basis by the Deputy Secretary of DOE.

Power and transmission rates for the CVP are established pursuant to the Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*) and the Reclamation Act of 1902 (43 U.S.C. 371 *et seq.*), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)) and Acts of Congress approved August 26, 1937 (50 Stat. 844, 850); August 12, 1955 (69 Stat. 719); and October 23, 1962 (76 Stat. 1173, 1191), and Acts amendatory or supplementary thereof.

By Amendment No. 3 to Delegation Order No. 0204-108, published November 10, 1993 (58 FR 59716), the Secretary of DOE delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to the Administrator of Western; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR Part 903) became effective on September 18, 1985 (50 FR 37835).

Availability of Information

All brochures, studies, comments, letters, memoranda, or other documents made or kept by Western for developing the Proposed Rates, are and will be made available for inspection and copying at the Sierra Nevada Region Office, located at 114 Parkshore Drive, Folsom, California 95630-4710.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

Pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*), each agency, when required to publish a proposed rule, is further required to prepare and make available for public comment an initial regulatory flexibility analysis to describe the impact of the proposed rule on small entities. Western has determined that (1) this rulemaking relates to services offered by the Sierra Nevada Region and therefore is not a rule within the purview of the Act, and (2) the proposed rates for the services offered by the Sierra Nevada Region would not cause an adverse economic impact to such entities. The requirements of this Act can be waived if the head of the agency certifies that the rule will not, if promulgated, have a significant economic impact on a substantial number of small entities. By his execution of this Federal Register notice, Western's Administrator certifies that no significant economic impact on a substantial number of small entities will occur.

Environmental Compliance

Pursuant to the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*); the Council on Environmental Quality Regulations for implementing NEPA (40 CFR Parts 1500 through 1508); and the DOE NEPA Implementing Procedures and Guidelines (10 CFR Part 1021), Western conducts environmental evaluations of the proposed rates and develops the appropriate level of environmental documentation.

Review Under the Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1980, 44 U.S.C. 3501-3520, Western has received approval from the Office of Management and Budget for the collection of customer information in this rule, under control number 1910-1200.

Determination Under Executive Order 12866

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

Issued at Golden, Colorado, February 20, 1997.

J.M. Shafer,

Administrator.

[FR Doc. 97-5256 Filed 3-4-97; 8:45 am]

BILLING CODE 6450-01-P

C-073355

C-073357

Western Area Power Administratio

Proposed Rates for Central Valley an California-Oregon Transmission Projects; Correction

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed rates; correction.

SUMMARY: The Western Area Power Administration published a document in the Federal Register of March 4, 1997, proposing rates for Central Valley Project and California-Oregon Transmission Project. The document contains an incorrect date.

FOR FURTHER INFORMATION CONTACT: Debbie Dietz, Rates Manager, Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4453.

Correction

In the Federal Register issue of March 4, 1997, in FR Doc. 97–5256, on page 9763, in the third column, correct the DATES caption to read:

DATES: The consultation and comment period will begin from the date of publication of this Federal Register notice and will end June 2,1997. A public information forum at which Western will present a detailed explanation of the Proposed Rates is scheduled for March 25, 1997, beginning at 9 a.m. PST, at the Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710. A public comment forum at which Western will receive oral and written comments is scheduled for April 24, 1997, beginning at 9 a.m. PDT, at the same location. Western should receive written comments by the end of the consultation and comment period to be assured consideration.

Issued in Washington, D.C. March 11, 1997.

Joel K. Bladow,

Assistant Administrator.

[FR Doc. 97–6583 Filed 3–14–97; 8:45 am]

BILLING CODE 6450–01–P

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION

SES Performance Review Board Members

March 11, 1997.

AGENCY: Equal Employment Opportunity Commission (EEOC)

ACTION: Notice.

SUMMARY: Notice is hereby given of the names of the members of the SES Performance Review Board of EEOC for FY 1996 and 1997.

FOR FURTHER INFORMATION CONTACT: Patricia Cornwell Johnson, Director, Human Resources Management Services, Equal Employment Opportunity Commission, 1801 L Street, N.W., Washington, D.C., 20507, (202) 663–4306.

SUPPLEMENTARY INFORMATION: Pursuant to the requirement of Section 4314(c)(1) Chapter 43 Title 5 U.S.C., membership of the SES Performance Review Board is as follows: Ms. Ronnie Blumenthal, Director, Office of Federal Operations, Equal Employment Opportunity Commission (Chairperson); Mr. Spencer H. Lewis, Director, New York District Office, Equal Employment Opportunity Commission; Mr. Federico Costales, Director, Miami District Office, Equal Employment Opportunity Commission; Ms. Issie Jenkins, Director, Baltimore District Office, Equal Employment Opportunity Commission (Alternate).

Signed at Washington, D.C. on this 5th day of March 1997.

For the Commission.

Gilbert F. Casellas,

Chairman.

[FR Doc. 97–6537 Filed 3–14–97; 8:45 am]

BILLING CODE 6570–06–M

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collections being Reviewed by the Federal Communications Commission

March 10, 1997.

SUMMARY: The Federal Communications Commissions, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection, as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarify of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Persons wishing to comment on this information collection should submit comments May 16, 1997.

ADDRESSES: Direct all comments to Dorothy Conway, Federal Communications Commissions, Room 234, 1919 M St., NW., Washington, DC 20554 or via internet to dconway@fcc.gov.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Dorothy Conway at 202–418–0217 or via internet at dconway@fcc.gov.

SUPPLEMENTARY INFORMATION:

OMB Approval Number: 3060–0565.

Title: Section 76.944 Commission review of franchising authority decisions on rates for the basic service tier and associated equipment.

Type of Review: Extension of existing collection.

Respondents: Business or other for-profit; state and local governments.

Number of Respondents: 300. (150 cable operators + 150 LFAs).

Estimated Time Per Response: 2–30 hours.

Total Annual Burden: 5,400 hours estimated as follows: We estimate that approximately 150 appeals are filed annually. For all aspects of the filing process (including appeals, oppositions and replies), we estimate that cable operators spend an average of 30 hours on each filing and that local franchising authorities spend an average of 20 hours on each filing.

We estimate that cable operators will use in-house legal staff to file requests for appeals approximately 50% of the time, therefore using outside legal assistance 50% of the time. When using outside legal assistance, operators are estimated to undergo a burden of 2 hours per filing to coordinate information with the outside legal assistance. 75 cable operators x 30 hours for in-house filings = 2,250. 75 cable operators x 2 hours for filings done by outside legal assistance = 150. 150 LFAs x 20 hours for each filing = 3,000. Total burden = 2,250 + 150 + 3,000 = 5,400 hours.

Cost to Respondents: We estimate the postage and stationery costs incurred by parties for appeal case to be $10 per party ($20 per case). 150 x $20 = $3,000. We estimate that cable operators

APPENDIX B

Central Valley Project

Power Repayment Study (PRS)

Executive Summary

APPENDIX B

Central Valley Project Power Repayment Study (PRS)
Executive Summary

	REVENUES	EXPENSES					ADJUSTMENT		CAPITALIZ
Fiscal Year	Total Revenue	Operations & Maintenance Expense	Purchased Power Expense	Other Expense	Interest Expense	Total Expenses	Prior Year Adjustments	Revenue After Annual Expenses	Incremental Deficit
1996	179,343,904	47,570,489	107,399,038	15,104,449	8,097,908	178,171,884	0	1,172,020	0
Miscellaneous Adjustment	**(39,500,395)**	**(38,420,905)**	**(97,911,175)**	**(11,679,137)**	**11,368,099**	**(136,643,118)**	**(97,142,723)**	**0**	
HISTORICAL SUBTOTAL	**3,850,614,782**	**551,569,049**	**2,289,325,106**	**343,891,262**	**322,984,330**	**3,507,769,747**	**0**	**342,845,035**	**0**
1997	164,343,729	41,922,528	95,450,000	15,029,000	9,893,533	162,295,061	0	2,048,668	0
1998	167,139,821	42,767,929	93,542,000	15,091,000	10,677,706	162,078,635	0	5,061,186	0
1999	159,894,821	43,609,949	81,776,000	15,091,000	10,493,281	150,970,230	0	8,924,591	0
2000	159,894,821	44,840,625	78,086,000	15,091,000	10,077,866	148,095,491	0	11,799,331	0
2001	152,994,821	42,609,592	69,446,000	15,091,000	9,447,850	136,594,442	0	16,400,379	0
2002	163,344,821	43,918,051	67,839,000	15,091,000	7,954,980	134,803,031	0	28,541,791	0
2003	163,344,821	43,918,051	75,838,000	15,091,000	6,327,423	141,174,474	0	22,170,348	0
2004	163,344,821	43,918,051	80,327,000	15,091,000	5,334,804	144,670,855	0	18,673,967	0
2005	101,842,881	43,918,051	27,220,000	8,011,000	5,254,372	84,403,423	0	17,439,458	0
2006	97,742,371	43,918,051	25,913,000	5,651,000	5,178,372	80,660,423	0	17,081,949	0
2007	96,818,231	43,918,051	25,913,000	5,651,000	4,740,517	80,222,568	0	16,595,664	0
2008	96,778,051	43,918,051	31,966,000	5,651,000	4,319,295	85,854,346	0	10,923,705	0
2009	96,737,871	43,918,051	31,966,000	5,651,000	4,030,457	85,565,508	0	11,172,364	0
2010	96,697,691	43,918,051	31,966,000	5,651,000	3,711,862	85,246,913	0	11,450,778	0
2011	96,275,801	43,918,051	31,966,000	5,651,000	3,380,163	84,915,214	0	11,360,587	0
2012	95,914,181	43,918,051	31,966,000	5,651,000	3,086,359	84,621,410	0	11,292,771	0
2013	95,874,001	43,918,051	31,966,000	5,651,000	2,815,021	84,350,072	0	11,523,930	0
2014	95,833,821	43,918,051	31,966,000	5,651,000	2,586,943	84,121,994	0	11,711,828	0
2015	95,753,461	43,918,051	31,966,000	5,651,000	2,726,390	84,261,441	0	11,492,020	0
2016	65,809,341	43,918,051	2,682,000	5,651,000	2,515,864	54,766,915	0	11,042,426	0
2017	65,072,781	43,918,051	0	5,651,000	2,239,186	51,808,237	0	13,264,544	0
2018	65,031,861	43,918,051	0	5,704,000	2,011,170	51,633,221	0	13,398,641	0
2019	65,018,221	43,918,051	0	5,704,000	1,718,609	51,340,660	0	13,677,561	0
2020	64,950,021	43,918,051	0	5,704,000	1,343,037	50,965,088	0	13,984,934	0
2021	64,120,341	43,918,051	0	5,704,000	1,271,280	50,893,331	0	13,227,010	0
2022	63,629,301	43,918,051	0	5,704,000	1,073,998	50,696,049	0	12,933,253	0
2023	63,561,101	43,918,051	0	5,704,000	818,862	50,440,913	0	13,120,188	0
2024	63,533,821	43,918,051	0	5,704,000	504,810	50,126,861	0	13,406,960	0
2025	63,533,821	43,918,051	0	5,704,000	222,117	49,844,168	0	13,689,653	0
2026	63,533,821	43,918,051	0	5,704,000	7,655	49,629,706	0	13,904,115	0

APPENDIX B

Central Valley Project Power Repayment Study (PRS)
Executive Summary

	REVENUES	EXPENSES					ADJUSTMENT		CAPITALIZI
Fiscal Year	Total Revenue	Operations & Maintenance Expense	Purchased Power Expense	Other Expense	Interest Expense	Total Expenses	Prior Year Adjustments	Revenue After Annual Expenses	Incremental Deficit
2027	63,533,821	43,918,051	0	5,704,000	25,248	49,647,299	0	13,886,523	0
2028	63,533,821	43,918,051	0	5,704,000	104,031	49,726,082	0	13,807,740	0
2029	63,533,821	43,918,051	0	5,704,000	240,089	49,862,140	0	13,671,682	0
2030	63,533,821	43,918,051	0	5,704,000	618,721	50,240,772	0	13,293,049	0
2031	63,533,821	43,918,051	0	6,744,000	434,699	51,096,750	0	12,437,071	0
2032	63,533,821	43,918,051	0	6,744,000	1,302,131	51,964,182	0	11,569,640	0
2033	63,533,821	43,918,051	0	6,744,000	2,210,529	52,872,580	0	10,661,241	0
2034	63,533,821	43,918,051	0	6,744,000	1,649,563	52,311,614	0	11,222,207	0
2035	63,533,821	43,918,051	0	6,744,000	1,228,530	51,890,581	0	11,643,240	0
2036	63,533,821	43,918,051	0	6,744,000	1,010,055	51,672,106	0	11,861,716	0
2037	63,533,821	43,918,051	0	6,744,000	1,778,307	52,440,358	0	11,093,464	0
2038	63,533,821	43,918,051	0	6,744,000	2,390,952	53,053,003	0	10,480,819	0
2039	63,533,821	43,918,051	0	6,744,000	1,932,821	52,594,872	0	10,938,949	0
2040	63,533,821	43,918,051	0	6,744,000	1,390,034	52,052,085	0	11,481,737	0
2041	63,533,821	43,918,051	0	6,744,000	684,633	51,346,684	0	12,187,137	0
2042	55,033,821	43,918,051	0	6,744,000	190,019	50,852,070	0	4,181,751	0
2043	55,033,821	43,918,051	0	6,744,000	169,312	50,831,363	0	4,202,458	0
2044	55,033,821	43,918,051	0	6,744,000	154,063	50,816,114	0	4,217,708	0
2045	55,033,821	43,918,051	0	6,744,000	384,300	51,046,351	0	3,987,470	0
2046	55,033,821	43,918,051	0	6,744,000	1,499,382	52,161,433	0	2,872,389	0
2047	55,033,821	43,918,051	0	6,744,000	2,309,654	52,971,705	0	2,062,116	0
2048	55,033,821	43,918,051	0	6,744,000	2,378,923	53,040,974	0	1,992,848	0
2049	55,033,823	43,918,051	0	6,744,000	2,430,677	53,092,728	0	1,941,096	0
Future YR SUBTOTAL	4,461,643,174	2,323,817,071	979,760,000	398,777,000	152,280,455	3,854,634,526	0	607,008,649	0
STUDY TOTAL	**8,312,257,956**	**2,875,386,120**	**3,269,085,106**	**742,668,262**	**475,264,784**	**7,362,404,272**	**0**	**949,853,684**	**0**

APPENDIX B

Central Valley Project Power Repayment Study (PRS)
Executive Summary

Fiscal Year	ED DEFICITS Unpaid Balance	Net Revenue for Investment Repayment	REPLACEMENTS Principal Payment	Unpaid Balance	Allowable Unpaid Balance	Cumulative Balance	PROJECT & ADDITIONS Principal Payment	Unpaid Balance	Allowable Unpaid Balance	Cumulative Balance
1996	0	1,172,020	46,772	6,504,173	45,139,344	46,774,119	1,125,248	220,070,886	506,115,071	522,645,975
Miscellaneous Adjustment										
HISTORICAL SUBTOTAL	0	342,845,035	40,269,946	6,504,173	45,139,344	46,774,119	302,575,089	220,070,886	506,115,071	522,645,975
1997	0	2,048,668	6,393	8,705,780	47,340,951	48,982,119	2,042,275	236,221,648	523,761,782	540,839,012
1998	0	5,061,186	77,832	10,439,948	49,075,119	50,794,119	4,983,354	237,618,680	529,831,695	547,219,399
1999	0	8,924,591	1,312,463	10,690,485	50,638,119	52,357,119	7,612,128	230,006,552	521,065,025	547,219,399
2000	0	11,799,331	10,352,715	9,590,076	59,432,884	61,609,425	1,446,615	228,559,937	510,743,064	547,219,399
2001	0	16,400,379	10,778,291	402,485	59,322,813	63,200,125	5,622,088	222,937,849	492,384,376	547,219,399
2002	0	28,541,791	2,412,376	402,485	61,735,189	65,612,501	26,129,415	196,808,434	483,177,727	547,219,399
2003	0	22,170,348	4,016,596	77,669	65,426,969	69,304,281	18,153,752	178,654,682	476,094,796	547,219,399
2004	0	18,673,967	4,025,030	0	69,374,330	73,251,642	14,648,937	164,005,745	463,485,090	547,219,399
2005	0	17,439,458	17,305,307	10,464,859	94,046,948	101,021,808	134,151	163,871,594	458,929,734	547,219,399
2006	0	17,081,949	12,238,616	0	95,820,705	102,795,565	4,843,333	159,028,261	444,168,195	547,219,399
2007	0	16,595,664	2,931,515	0	98,752,220	105,727,080	13,664,149	145,364,112	409,081,374	547,219,399
2008	0	10,923,705	1,910,060	0	100,662,279	107,637,139	9,013,646	136,350,467	408,505,898	547,219,399
2009	0	11,172,364	0	413,157	101,072,781	108,050,296	11,172,364	125,178,103	407,459,260	547,219,399
2010	0	11,450,778	0	836,797	101,394,558	108,473,937	11,450,778	113,727,325	406,168,467	547,219,399
2011	0	11,360,587	0	933,163	101,366,566	108,570,303	11,360,587	102,366,738	405,233,459	547,219,399
2012	0	11,292,771	0	3,702,723	103,973,630	111,339,862	11,292,771	91,073,967	394,134,101	547,219,399
2013	0	11,523,930	1,389,779	3,771,390	105,151,825	112,798,308	10,134,151	80,939,816	294,547,178	547,219,399
2014	0	11,711,828	15,225	9,872,071	110,472,083	118,914,214	11,696,603	69,243,213	251,955,553	547,219,399
2015	0	11,492,020	11,357,869	7,168,079	113,623,164	127,568,091	134,151	69,109,062	251,496,512	547,219,399
2016	0	11,042,426	10,908,275	4,139,547	120,686,669	135,447,834	134,151	68,974,911	251,014,729	547,219,399
2017	0	13,264,544	9,460,290	0	124,651,438	140,768,577	3,804,254	65,170,656	250,561,672	547,219,399
2018	0	13,398,641	0	5,845,051	130,496,349	146,613,628	13,398,641	51,772,016	250,082,577	547,219,399
2019	0	13,677,561	0	7,131,076	131,623,800	147,899,653	13,677,561	38,094,455	249,575,621	547,219,399
2020	0	13,984,934	0	7,999,813	131,944,478	148,768,390	13,984,934	24,109,521	249,038,856	547,219,399
2021	0	13,227,010	13,145,919	7,007,614	142,930,269	160,922,110	81,091	24,028,430	248,470,193	547,219,399
2022	0	12,933,253	10,852,162	4,627,910	151,401,678	169,394,568	2,081,091	21,947,339	247,867,400	547,219,399
2023	0	13,120,188	0	7,365,699	143,617,517	172,132,357	13,120,188	8,827,151	237,694,931	547,219,399
2024	0	13,406,960	5,066,363	4,702,947	143,994,141	174,535,969	8,340,597	486,554	237,016,544	547,219,399
2025	0	13,689,653	10,104,869	0	141,313,068	179,937,891	486,554	0	236,296,345	547,219,399
2026	0	13,904,115	510,356	0	141,819,566	180,448,246	0	0	235,531,409	547,219,399

APPENDIX B

Central Valley Project Power Repayment Study (PRS)
Executive Summary

Fiscal Year	ED DEFICITS Unpaid Balance	Net Revenue for Investment Repayment	REPLACEMENTS Principal Payment	REPLACEMENTS Unpaid Balance	REPLACEMENTS Allowable Unpaid Balance	REPLACEMENTS Cumulative Balance	PROJECT & ADDITIONS Principal Payment	PROJECT & ADDITIONS Unpaid Balance	PROJECT & ADDITIONS Allowable Unpaid Balance	PROJECT & ADDITIONS Cumulative Balance
2027	0	13,886,523	0	1,683,183	139,992,568	182,131,429	0	0	234,718,604	547,219,399
2028	0	13,807,740	0	5,252,195	140,717,192	185,700,441	0	0	233,854,579	547,219,399
2029	0	13,671,682	0	10,753,726	143,941,855	191,201,972	0	0	232,935,748	547,219,399
2030	0	13,293,049	8,575,982	10,810,816	151,362,759	199,835,045	0	0	140,637,268	547,219,399
2031	0	12,437,071	12,437,071	1,025,822	150,419,495	202,487,122	0	0	140,637,268	547,219,399
2032	0	11,569,640	11,569,640	34,430,560	192,949,558	247,461,499	0	0	140,279,775	547,219,399
2033	0	10,661,241	10,661,241	25,761,066	193,032,056	249,453,247	0	0	140,279,775	547,219,399
2034	0	11,222,207	11,222,207	19,155,731	195,592,905	254,070,119	0	0	135,888,613	547,219,399
2035	0	11,643,240	11,643,240	14,296,536	192,268,433	260,854,165	0	0	135,888,613	547,219,399
2036	0	11,861,716	11,861,716	13,206,760	191,946,987	271,626,104	0	0	117,582,185	547,219,399
2037	0	11,093,464	11,093,464	35,215,655	221,872,765	304,728,463	0	0	114,944,777	547,219,399
2038	0	10,480,819	10,480,819	29,888,779	223,809,500	309,882,405	0	0	114,944,777	547,219,399
2039	0	10,938,949	10,938,949	22,740,994	224,017,413	313,673,570	0	0	113,897,428	547,219,399
2040	0	11,481,737	11,481,737	15,108,938	224,401,222	317,523,250	0	0	115,936,428	547,219,399
2041	0	12,187,137	12,187,137	3,533,293	224,449,765	318,134,742	0	0	115,936,428	547,219,399
2042	0	4,181,751	4,181,751	1,640,839	225,626,617	320,424,040	0	0	112,532,700	547,219,399
2043	0	4,202,458	4,202,458	2,969,449	227,474,899	325,955,107	0	0	73,226,527	547,219,399
2044	0	4,217,708	4,217,708	1,225,607	229,715,671	328,428,973	0	0	73,063,561	547,219,399
2045	0	3,987,470	3,987,470	9,238,690	232,792,048	340,429,527	0	0	47,507,265	547,219,399
2046	0	2,872,389	2,872,389	31,588,731	237,580,612	365,651,956	0	0	24,573,424	547,219,399
2047	0	2,062,116	2,062,116	31,302,012	237,987,167	367,427,354	0	0	6,380,387	547,219,399
2048	0	1,992,848	1,992,848	33,474,884	238,679,587	371,593,073	0	0	0	547,219,399
2049	0	1,941,096	1,941,096	32,711,250	239,246,481	372,770,535	0	0	0	547,219,399
Future YR SUBTOTAL		607,008,649	299,789,339				244,644,310			
STUDY TOTAL	0	949,853,684	340,059,285	32,711,250	239,246,481	372,770,535	547,219,399	0	0	547,219,399

APPENDIX B

Central Valley Project Power Repayment Study (PRS)
Executive Summary

	AID TO IRRIGATION				
Fiscal Year	Principal Payment	Unpaid Balance	Allowable Unpaid Balance	Cumulative Balance	Surplus Revenues
1996	0	62,575,000	62,575,000	62,575,000	0
Miscellaneous Adjustment					
HISTORICAL SUBTOTAL	**0**	**62,575,000**	**62,575,000**	**62,575,000**	**0**
1997	0	62,575,000	62,575,000	62,575,000	0
1998	0	62,575,000	62,575,000	62,575,000	0
1999	0	62,575,000	62,575,000	62,575,000	0
2000	0	62,575,000	62,575,000	62,575,000	0
2001	0	62,575,000	62,575,000	62,575,000	0
2002	0	62,575,000	62,575,000	62,575,000	0
2003	0	62,575,000	62,575,000	62,575,000	0
2004	0	62,575,000	62,575,000	62,575,000	0
2005	0	62,575,000	62,575,000	62,575,000	0
2006	0	62,575,000	62,575,000	62,575,000	0
2007	0	62,575,000	62,575,000	62,575,000	0
2008	0	62,575,000	62,575,000	62,575,000	0
2009	0	62,575,000	62,575,000	62,575,000	0
2010	0	62,575,000	62,575,000	62,575,000	0
2011	0	62,575,000	62,575,000	62,575,000	0
2012	0	62,575,000	62,575,000	62,575,000	0
2013	0	62,575,000	62,575,000	62,575,000	0
2014	0	62,575,000	62,575,000	62,575,000	0
2015	0	62,575,000	62,575,000	62,575,000	0
2016	0	62,575,000	62,575,000	62,575,000	0
2017	0	62,575,000	62,575,000	62,575,000	0
2018	0	62,575,000	62,575,000	62,575,000	0
2019	0	62,575,000	62,575,000	62,575,000	0
2020	0	62,575,000	62,575,000	62,575,000	0
2021	0	62,575,000	62,575,000	62,575,000	0
2022	0	62,575,000	62,575,000	62,575,000	0
2023	0	62,575,000	62,575,000	62,575,000	0
2024	0	62,575,000	62,575,000	62,575,000	0
2025	3,098,230	59,476,770	62,575,000	62,575,000	0
2026	13,393,759	46,083,011	62,575,000	62,575,000	0

APPENDIX B

Central Valley Project Power Repayment Study (PRS)
Executive Summary

Fiscal Year	AID TO IRRIGATION Principal Payment	Unpaid Balance	Allowable Unpaid Balance	Cumulative Balance	Surplus Revenues
2027	13,886,523	32,196,488	62,575,000	62,575,000	0
2028	13,807,740	18,388,748	62,575,000	62,575,000	0
2029	13,671,682	4,717,067	62,575,000	62,575,000	0
2030	4,717,067	0	0	62,575,000	0
2031	0	0	0	62,575,000	0
2032	0	0	0	62,575,000	0
2033	0	0	0	62,575,000	0
2034	0	0	0	62,575,000	0
2035	0	0	0	62,575,000	0
2036	0	0	0	62,575,000	0
2037	0	0	0	62,575,000	0
2038	0	0	0	62,575,000	0
2039	0	0	0	62,575,000	0
2040	0	0	0	62,575,000	0
2041	0	0	0	62,575,000	0
2042	0	0	0	62,575,000	0
2043	0	0	0	62,575,000	0
2044	0	0	0	62,575,000	0
2045	0	0	0	62,575,000	0
2046	0	0	0	62,575,000	0
2047	0	0	0	62,575,000	0
2048	0	0	0	62,575,000	0
2049	0	0	0	62,575,000	0
Future YR SUBTOTAL	62,575,000				0
STUDY TOTAL	62,575,000	0	0	62,575,000	0

APPENDIX C

Projected CVP Customers Load Forecast

APPENDIX C

Total Projected Capacity Energy Load Forecast

	OCTOBER			NOVEMBER			DECEMBER			JANUARY		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Alameda, Scheduled	1,145	617,109	0.7244	1,145	617,109	0.7486	1,145	617,109	0.7244	1,085	561,008	0.6952
Arvin-Edison	10,148	5,194,140	0.6879	6,422	3,286,800	0.7109	2,675	1,368,960	0.6879	8,362	4,279,860	0.6879
Avenal*	595	254,193	0.5745	586	250,387	0.5937	494	211,376	0.5745	444	189,749	0.5745
Banta-Carbona ID	117	50,660	0.5829	79	34,362	0.6024	65	28,049	0.5829	96	41,664	0.5829
BART	57,549	17,728,255	0.4141	55,618	17,133,280	0.4279	58,849	18,128,517	0.4141	59,537	18,340,547	0.4141
Beale AFB	17,692	8,738,850	0.6639	20,668	10,209,240	0.6860	22,650	11,188,105	0.6639	22,748	11,236,260	0.6639
Biggs, Scheduled*	348	157,928	0.6093	1,510	789,840	0.7265	232	131,607	0.7616	0	0	#DIV/0!
Broadview WD*	245	76,475	0.4191	585	182,574	0.4331	158	49,321	0.4191	367	114,351	0.4191
Byron-Bethany	328	119,200	0.4877	112	40,500	0.5040	28	10,156	0.4877	49	17,856	0.4877
Calaveras Public Power	4,232	1,544,012	0.4904	5,122	1,868,760	0.5068	5,699	2,079,480	0.4904	4,996	1,822,800	0.4904
Castle Joint Power Authority	4,198	2,038,185	0.6526	3,737	1,814,331	0.6743	4,275	2,075,681	0.6526	4,309	2,092,049	0.6526
Cawelo WD*	2,514	1,108,421	0.5927	2,725	1,201,635	0.6124	2,401	1,058,805	0.5927	2,707	1,193,562	0.5927
Concord NWS*	2,187	962,302	0.5915	2,151	946,404	0.6112	2,239	985,074	0.5915	2,242	986,421	0.5915
CSUS Nimbus	16	4,172	0.3436	20	5,040	0.3551	20	5,208	0.3436	23	5,952	0.3436
Delano-Earlimart*	673	378,906	0.7569	150	84,729	0.7821	79	44,586	0.7569	152	85,705	0.7569
Dixon NRS*	740	402,463	0.7312	705	383,405	0.7555	681	370,389	0.7312	713	388,100	0.7312
Duel*	1,765	832,376	0.6339	1,759	829,780	0.6551	1,860	877,076	0.6339	1,860	877,076	0.6339
East Bay MUD*	5,808	3,326,226	0.7698	5,685	3,255,928	0.7955	4,239	2,427,763	0.7698	3,972	2,274,833	0.7698
East Contra Costa* now 2 deliverys	462	199,239	0.5802	117	50,301	0.5996	181	77,967	0.5802	422	182,338	0.5802
Folsom Prison	2,282	1,053,802	0.6208	2,277	1,051,560	0.6415	2,445	1,129,392	0.6208	2,464	1,137,948	0.6208
Glenn-Colusa	542	301,818	0.7479	453	251,870	0.7728	103	57,258	0.7479	109	60,373	0.7479
Gridley, Scheduled	3,253	1,539,250	0.6361	3,643	1,693,175	0.6455	2,385	1,077,475	0.6073	1,626	769,625	0.6363
Healdsburg, Scheduled	1,941	1,061,263	0.7349	1,941	1,061,263	0.7594	1,941	1,061,263	0.7349	1,941	1,157,741	0.7479
James ID*	433	126,264	0.3916	134	39,123	0.4047	17	5,082	0.3916	159	46,202	0.3916
Kern-Tulare WD*	1,046	377,827	0.4854	516	186,300	0.5016	288	103,955	0.4854	5	1,925	0.4854
Lassen MUD	20,075	10,430,000	0.6983	20,094	10,440,000	0.7216	20,478	10,639,200	0.6983	21,051	10,936,800	0.6983
Lawrence Berkley	16,910	9,117,574	0.7247	17,137	9,239,958	0.7489	16,301	8,789,178	0.7247	17,122	9,231,799	0.7247
Lemoore NAS	14,300	7,016,783	0.6595	11,861	5,820,012	0.6815	15,105	7,411,635	0.6595	16,015	7,858,258	0.6595
Lindsay-Strathmore*	673	378,906	0.7569	150	84,729	0.7821	79	44,586	0.7569	152	85,705	0.7569
LLNL - Direct Service	11,855	6,284,279	0.7125	12,045	6,384,853	0.7362	11,611	6,155,155	0.7125	10,777	5,712,627	0.7125
Lodi, Scheduled	6,636	3,516,391	0.7122	6,636	3,516,391	0.7360	6,636	3,516,391	0.7122	6,636	3,838,063	0.7770
Lompoc, Scheduled	3,897	2,020,326	0.6968	3,897	2,020,326	0.7200	3,897	2,020,326	0.6968	3,897	2,203,992	0.7602
Lower Tule River ID*	1,289	422,828	0.4408	1,826	598,700	0.4555	870	285,199	0.4408	113	36,966	0.4408
Mare Island	3,479	1,698,600	0.6562	3,097	1,512,000	0.6781	3,543	1,729,800	0.6562	3,475	1,696,320	0.6562
McClellan AFB	12,051	5,793,120	0.6461	11,557	5,555,520	0.6677	12,443	5,981,760	0.6461	12,443	5,981,760	0.6461
Modesto ID	6,754	3,694,824	0.7353	7,936	4,341,016	0.7598	7,958	4,353,075	0.7353	8,211	4,491,746	0.7353
Moffit Field	4,445	2,338,134	0.7070	4,314	2,269,388	0.7306	4,626	2,433,438	0.7070	4,675	2,458,992	0.7070
NASA-Ames	74,238	19,966,000	0.3615	77,101	20,736,000	0.3735	77,458	20,832,000	0.3615	75,245	20,236,800	0.3615
Naval Supply Center-includes Treasure Island	12,530	6,347,400	0.6809	10,298	5,216,400	0.7036	12,314	6,237,696	0.6809	13,079	6,625,320	0.6809
NCa Youth Center*	1,673	819,268	0.6582	1,850	905,791	0.6801	1,818	890,166	0.6582	1,805	883,621	0.6582
Onizuka AFB*	3,604	2,293,948	0.8556	3,667	2,334,339	0.8841	3,789	2,412,150	0.8556	3,726	2,371,723	0.8556
Palo Alto, Scheduled	133,515	64,473,302	0.6490	138,700	70,920,632	0.7102	125,004	64,473,302	0.6932	129,253	64,473,302	0.6704
Park & Rec	31	8,627	0.3710	39	10,724	0.3833	46	12,722	0.3710	46	12,611	0.3710
Parks Army*	254	115,661	0.6116	230	104,794	0.6320	231	105,341	0.6116	233	105,919	0.6116
Patterson WD*	11	3,308	0.4077	43	13,116	0.4213	6	1,771	0.4077	5	1,482	0.4077

APPENDIX C

Total Projected Capacity Energy
Load Forecast

	FEBRUARY			MARCH			APRIL			MAY		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Alameda, Scheduled	759	392,706	0.7699	304	224,403	0.9935	326	224,403	0.9572	326	224,403	0.9263
Arvin-Edison	10,438	5,342,400	0.7616	17,400	8,905,680	0.6879	20,819	10,655,580	0.7109	23,909	12,236,940	0.6879
Avenal*	472	201,562	0.6361	357	152,468	0.5745	585	249,950	0.5937	515	220,324	0.5745
Banta-Carbona ID	64	27,821	0.6454	72	31,114	0.5829	1,492	647,100	0.6024	3,027	1,312,714	0.5829
BART	51,910	15,992,432	0.4585	55,407	17,068,370	0.4141	57,869	17,826,648	0.4279	58,505	18,022,502	0.4141
Beale AFB	18,638	9,206,484	0.7351	20,628	10,189,080	0.6639	18,734	9,253,530	0.6860	18,948	9,359,520	0.6639
Biggs, Scheduled*	0	0	#DIV/0!	146	105,285	0.9684	116	78,964	0.9444	116	78,964	0.9140
Broadview WD*	217	67,552	0.4641	215	66,993	0.4191	597	186,041	0.4331	455	141,887	0.4191
Byron-Bethany	21	7,560	0.5400	76	27,677	0.4877	1,439	522,174	0.5040	2,291	831,197	0.4877
Calaveras Public Power	5,006	1,826,496	0.5430	5,142	1,875,996	0.4904	4,918	1,794,264	0.5068	4,505	1,643,868	0.4904
Castle Joint Power Authority	3,682	1,787,452	0.7225	3,885	1,885,969	0.6526	3,638	1,766,446	0.6743	3,984	1,934,327	0.6526
Cawelo WD*	1,084	478,170	0.6562	2,052	904,797	0.5927	1,477	651,144	0.6124	2,401	1,058,805	0.5927
Concord NWS*	2,223	978,075	0.6548	2,536	1,115,788	0.5915	2,149	945,834	0.6112	2,099	923,470	0.5915
CSUS Nimbus	18	4,570	0.3804	20	5,059	0.3436	20	5,177	0.3551	14	3,571	0.3436
Delano-Earlimart*	192	107,875	0.8380	408	230,002	0.7569	1,134	638,494	0.7821	1,688	950,391	0.7569
Dixon NRS*	611	332,389	0.8095	674	366,539	0.7312	641	348,715	0.7555	655	356,144	0.7312
Duel*	1,692	798,109	0.7019	1,873	883,621	0.6339	1,770	834,953	0.6551	1,707	805,077	0.6339
East Bay MUD*	4,823	2,762,605	0.8523	5,000	2,863,613	0.7698	4,387	2,512,450	0.7955	5,881	3,368,282	0.7698
East Contra Costa*	43	18,431	0.6424	105	45,359	0.5802	1,534	662,307	0.5996	2,697	1,164,300	0.5802
Folsom Prison	2,192	1,012,368	0.6873	2,334	1,078,056	0.6208	2,274	1,050,100	0.6415	2,260	1,043,832	0.6208
Glenn-Colusa	83	46,405	0.8280	170	94,327	0.7479	1,739	967,465	0.7728	3,484	1,938,475	0.7479
Gridley, Scheduled	1,100	615,700	0.8329	900	615,700	0.9197	1,301	769,625	0.8214	1,844	1,077,475	0.7855
Healdsburg, Scheduled	1,320	868,306	0.9789	526	385,914	0.9865	433	289,435	0.9275	542	289,435	0.7174
James ID*	406	118,308	0.4336	39	11,435	0.3916	44	12,837	0.4047	57	16,495	0.3916
Kern-Tulare WD*	29	10,346	0.5374	107	38,502	0.4854	927	334,874	0.5016	2,330	841,538	0.4854
Lassen MUD	17,849	9,273,600	0.7731	19,189	9,969,600	0.6983	19,236	9,994,100	0.7216	19,475	10,118,400	0.6983
Lawrence Berkley	15,676	8,452,824	0.8024	18,294	9,864,114	0.7247	17,226	9,288,231	0.7489	16,887	9,105,336	0.7247
Lemoore NAS	12,633	6,198,822	0.7302	13,182	6,468,336	0.6595	12,208	5,990,528	0.6815	14,061	6,899,558	0.6595
Lindsay-Strathmore*	192	107,875	0.8380	408	230,002	0.7569	1,134	638,494	0.7821	1,688	950,391	0.7569
LLNL - Direct Service	8,774	4,651,080	0.7888	12,294	6,517,222	0.7125	11,148	5,909,450	0.7362	10,928	5,793,086	0.7125
Lodi, Scheduled	6,600	2,877,047	0.6487	1,805	1,278,688	0.9521	1,844	959,016	0.7225	1,626	959,016	0.7928
Lompoc, Scheduled	3,300	1,652,994	0.7454	1,203	734,664	0.8206	976	550,998	0.7843	867	550,998	0.8544
Lower Tule River ID*	2,592	850,113	0.4880	824	270,284	0.4408	29	9,451	0.4555	30	9,910	0.4408
Mare Island	2,891	1,411,200	0.7265	2,972	1,450,800	0.6562	2,784	1,358,910	0.6781	2,972	1,450,800	0.6562
McClellan AFB	11,776	5,660,928	0.7154	12,406	5,963,904	0.6461	12,187	5,858,412	0.6677	11,372	5,466,614	0.6461
Modesto ID	7,516	4,111,519	0.8140	8,399	4,594,243	0.7353	7,584	4,148,536	0.7598	6,580	3,599,426	0.7353
Moffit Field	4,131	2,172,660	0.7827	4,501	2,367,408	0.7070	4,309	2,266,461	0.7306	4,517	2,376,150	0.7070
NASA-Ames	77,957	20,966,400	0.4002	82,990	22,320,000	0.3615	80,202	21,570,000	0.3735	88,523	23,808,000	0.3615
Naval Supply Center	12,785	6,476,500	0.7538	13,063	6,617,322	0.6809	11,165	5,655,654	0.7036	11,985	6,071,040	0.6809
NCa Youth Center*	1,799	880,876	0.7287	1,925	942,529	0.6582	1,757	860,255	0.6801	1,684	824,713	0.6582
Onizuka AFB*	3,346	2,130,030	0.9473	3,345	2,129,161	0.8556	3,519	2,239,937	0.8841	3,768	2,398,675	0.8556
Palo Alto, Scheduled	98,252	45,131,311	0.6835	51,509	25,789,321	0.6730	60,713	25,789,321	0.5900	59,629	32,236,651	0.7266
Park & Rec	52	14,448	0.4107	39	10,714	0.3710	36	10,066	0.3833	39	10,714	0.3710
Parks Army*	199	90,556	0.6772	275	125,132	0.6116	280	127,252	0.6320	288	130,983	0.6116
Patterson WD*	4	1,218	0.4514	1	208	0.4077	689	209,019	0.4213	1,031	312,836	0.4077

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APPENDIX C

Total Projected Capacity Energy
Load Forecast

	JUNE			JULY			AUGUST			SEPTEMBER		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Alameda, Scheduled	759	336,605	0.6160	1,145	617,109	0.7244	1,145	617,109	0.7244	1,145	561,008	0.6805
Arvin-Edison	24,913	12,751,200	0.7109	21,681	11,096,760	0.6879	22,623	11,578,872	0.6879	15,460	7,912,800	0.7109
Avenal*	724	309,556	0.5937	875	374,072	0.5745	740	316,117	0.5745	727	310,555	0.5937
Banta-Carbona ID	2,356	1,021,680	0.6024	2,181	945,810	0.5829	1,394	604,500	0.5829	312	135,432	0.6024
BART	58,282	17,954,036	0.4279	56,784	17,492,429	0.4141	57,472	17,704,458	0.4141	56,218	17,317,950	0.4279
Beale AFB	19,870	9,815,040	0.6860	22,423	11,075,742	0.6639	22,260	10,995,483	0.6639	20,441	10,097,100	0.6860
Biggs, Scheduled*	116	78,964	0.9444	232	131,607	0.7616	1,605	710,676	0.5950	813	368,499	0.6296
Broadview WD*	747	232,875	0.4331	623	194,435	0.4191	543	169,409	0.4191	183	57,008	0.4331
Byron-Bethany	2,283	828,360	0.5040	2,276	825,840	0.4877	1,921	697,221	0.4877	1,341	486,486	0.5040
Calaveras Public Power	5,830	2,127,240	0.5068	5,975	2,179,920	0.4904	7,137	2,604,000	0.4904	5,723	2,088,000	0.5068
Castle Joint Power Authority	3,559	1,727,934	0.6743	3,862	1,874,809	0.6526	3,624	1,759,493	0.6526	4,145	2,012,324	0.6743
Cawelo WD*	3,802	1,676,700	0.6124	3,929	1,732,590	0.5927	3,274	1,443,825	0.5927	2,683	1,183,005	0.6124
Concord NWS*	2,103	925,538	0.6112	2,355	1,036,089	0.5915	2,284	1,004,902	0.5915	1,931	849,528	0.6112
CSUS Nimbus	11	2,851	0.3551	16	4,092	0.3436	20	5,208	0.3436	17	4,320	0.3551
Delano-Earlimart*	1,881	1,059,356	0.7821	1,926	1,084,362	0.7569	1,608	905,734	0.7569	1,232	693,930	0.7821
Dixon NRS*	637	346,518	0.7555	733	398,881	0.7312	728	396,186	0.7312	767	417,312	0.7555
Duel*	1,665	785,441	0.6551	1,707	805,077	0.6339	1,790	844,349	0.6339	1,665	785,441	0.6551
East Bay MUD*	5,297	3,033,933	0.7955	5,607	3,211,528	0.7698	5,541	3,173,297	0.7698	5,426	3,107,931	0.7955
East Contra Costa*	2,778	1,199,213	0.5996	2,400	1,035,858	0.5802	1,745	753,099	0.5802	1,102	475,736	0.5996
Folsom Prison	2,133	985,320	0.6415	2,353	1,086,612	0.6208	2,353	1,086,612	0.6208	2,234	1,031,688	0.6415
Glenn-Colusa	3,893	2,165,954	0.7728	4,165	2,317,269	0.7479	3,760	2,092,074	0.7479	1,512	841,171	0.7728
Gridley, Scheduled	1,192	769,625	0.8964	3,686	1,847,100	0.6735	5,943	2,924,575	0.6614	3,379	1,693,175	0.6959
Healdsburg, Scheduled	1,301	289,435	0.3089	1,941	868,306	0.6013	1,941	1,157,741	0.8017	1,941	1,157,741	0.8284
James ID*	632	184,046	0.4047	1,722	501,619	0.3916	1,695	494,019	0.3916	997	290,528	0.4047
Kern-Tulare WD*	3,280	1,184,570	0.5016	3,389	1,224,055	0.4854	1,907	688,532	0.4854	2,255	814,392	0.5016
Lassen MUD	19,956	10,368,000	0.7216	20,478	10,639,200	0.6983	21,194	11,011,200	0.6983	20,926	10,872,000	0.7216
Lawrence Berkley	16,569	8,933,999	0.7489	16,183	8,725,947	0.7247	17,473	9,421,493	0.7247	14,753	7,954,930	0.7489
Lemoore NAS	15,582	7,645,752	0.6815	18,361	9,009,468	0.6595	18,926	9,286,682	0.6595	15,787	7,746,354	0.6815
Lindsay-Strathmore*	1,881	1,059,356	0.7821	1,926	1,084,362	0.7569	1,608	905,734	0.7569	1,232	693,930	0.7821
LLNL - Direct Service	10,282	5,450,485	0.7362	10,928	5,793,086	0.7125	10,928	5,793,086	0.7125	10,429	5,528,349	0.7362
Lodi, Scheduled	1,844	959,016	0.7225	5,530	2,877,047	0.6993	6,636	3,836,063	0.7770	6,636	3,836,063	0.8029
Lompoc, Scheduled	1,085	550,998	0.7056	3,036	1,652,994	0.7318	3,897	2,203,992	0.7602	3,897	2,203,992	0.7855
Lower Tule River ID*	31	10,328	0.4555	54	17,711	0.4408	421	138,030	0.4408	1,779	583,492	0.4555
Mare Island	2,655	1,296,000	0.6781	2,743	1,339,200	0.6562	2,515	1,227,600	0.6562	2,876	1,404,000	0.6781
McClellan AFB	11,718	5,633,280	0.6677	12,146	5,838,912	0.6461	12,128	5,829,984	0.6461	11,772	5,659,200	0.6677
Modesto ID	5,610	3,069,053	0.7598	6,382	3,490,901	0.7353	6,547	3,581,338	0.7353	6,197	3,389,961	0.7598
Moffit Field	4,216	2,217,600	0.7306	4,369	2,297,967	0.7070	4,464	2,348,287	0.7070	4,364	2,295,261	0.7306
NASA-Ames	88,880	23,904,000	0.3735	76,351	20,534,400	0.3615	79,671	21,427,200	0.3615	81,384	21,888,000	0.3735
Naval Supply Center	12,195	6,177,600	0.7036	11,739	5,946,420	0.6809	12,076	6,117,540	0.6809	11,022	5,583,600	0.7036
NCa Youth Center*	1,578	772,772	0.6801	1,791	877,076	0.6582	1,805	883,621	0.6582	1,630	798,109	0.6801
Onizuka AFB*	3,524	2,243,052	0.8841	3,768	2,398,675	0.8556	3,789	2,412,150	0.8556	3,626	2,308,257	0.8841
Palo Alto, Scheduled	50,384	32,236,651	0.8886	124,678	70,920,632	0.7646	138,700	77,367,962	0.7497	138,700	70,920,632	0.7102
Park & Rec	41	11,340	0.3833	43	11,904	0.3710	43	11,904	0.3710	49	13,608	0.3833
Parks Army*	324	147,655	0.6320	341	155,163	0.6116	327	149,003	0.6116	293	133,205	0.6320
Patterson WD*	922	279,558	0.4213	1,078	326,882	0.4077	1,010	306,514	0.4077	225	68,105	0.4213

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APPENDIX C

Total Projected Capacity Energy Load Forecast

	Capacity (kW)	TOTAL Energy (kWh)	Load Factor	
Alameda, Scheduled	10,427	5,610,085	0.7370	5450,083
Arvin-Edison	184,850	94,609,992	0.7011	
Avenal*	7,113	3,040,308	0.5856	
Banta-Carbona ID	11,254	4,880,906	0.5941	
BART	684,000	210,709,423	0.4220	
Beale AFB	245,700	121,364,434	0.6766	
Biggs, Scheduled*	5,235	2,632,134	0.6887	
Broadview WD*	4,935	1,538,922	0.4272	
Byron-Bethany	12,165	4,414,227	0.4971	
Calaveras Public Power	64,284	23,454,836	0.4998	
Castle Joint Power Authority	46,898	22,769,000	0.6651	
Cawelo WD*	31,050	13,691,459	0.6040	
Concord NWS*	26,496	11,659,425	0.6028	
CSUS Nimbus	216	55,220	0.3502	
Delano-Earlimart*	11,124	6,264,069	0.7714	
Dixon NRS*	8,285	4,507,041	0.7452	
Duel*	21,114	9,958,375	0.6461	
East Bay MUD*	61,665	35,318,390	0.7846	
East Contra Costa*	13,584	5,864,148	0.5913	
Folsom Prison	27,600	12,747,290	0.6327	
Glenn-Colusa	20,011	11,134,461	0.7622	10,934,459
Gridley, Scheduled	30,252	15,392,501	0.6970	15,267,501
Healdsburg, Scheduled	17,710	9,647,845	0.7463	9,437,845
James ID*	6,335	1,845,957	0.3991	
Kern-Tulare WD*	16,079	5,806,816	0.4947	
Lassen MUD	240,000	124,692,100	0.7117	
Lawrence Berkley	200,532	108,125,182	0.7386	88,435,183
Lemoore NAS	178,020	87,352,189	0.6722	
Lindsay-Strathmore*	11,124	6,264,069	0.7714	
LLNL - Direct Service	132,000	69,972,760	0.7262	64,672,758
Lodi, Scheduled	59,064	31,967,191	0.7414	31,667,177
Lompoc, Scheduled	33,849	18,366,602	0.7433	
Lower Tule River ID*	9,858	3,233,011	0.4492	
Mare Island	36,000	17,575,230	0.6688	
McClellan AFB	144,000	69,223,394	0.6585	
Modesto ID	85,673	46,865,638	0.7494	
Moffit Field	52,931	27,841,726	0.7205	
NASA-Ames	960,000	258,188,800	0.3684	
Naval Supply Center	144,250	73,072,492	0.6939	
NCa Youth Center*	21,114	10,338,796	0.6708	
Onizuka AFB*	43,470	27,672,096	0.8720	
Palo Alto, Scheduled	1,249,038	644,733,015	0.7071	
Park & Rec	505	139,382	0.3781	
Parks Army*	3,276	1,490,664	0.6234	
Patterson WD*	5,024	1,524,017	0.4156	

APPENDIX C

Total Projected Capacity Energy Load Forecast

	OCTOBER			NOVEMBER		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Plumas-Sierra, Scheduled	11,926	6,248,319	0.7042	16,609	7,636,834	0.6386
Provident ID*	117	52,187	0.5977	248	110,350	0.6176
Rag Gulch WD*	686	269,876	0.5285	136	53,654	0.5461
RD 2035*	156	31,763	0.2730	650	131,929	0.2821
Redding, Scheduled	82,000	41,181,000	0.6750	90,000	45,283,000	0.6988
Roseville, Scheduled	44,700	25,451,203	0.7653	44,700	25,451,203	0.7908
San Juan Suburban	921	447,000	0.6522	631	306,000	0.6739
San Luis - Fitjie*	20	6,940	0.4564	53	18,028	0.4716
San Luis - Kaljian*	9	3,072	0.4833	7	2,670	0.4994
Santa Clara Valley*	1,018	557,641	0.7361	720	394,092	0.7606
Santa Clara, Scheduled	152,980	56,577,220	0.4971	150,856	56,577,220	0.5209
Sharpe Depot	3,816	1,745,472	0.6148	3,471	1,587,744	0.6353
Shasta Lake, City of, Scheduled	11,202	4,789,153	0.5746	11,450	4,789,153	0.5809
Sierra Conservation*	1,923	1,040,951	0.7276	1,956	1,059,078	0.7519
Site 300	2,114	1,202,542	0.7647	2,412	1,372,140	0.7902
SLAC	48,967	30,724,254	0.8434	48,955	30,717,144	0.8715
SMUD	361,000	131,498,080	0.4896	361,000	197,247,121	0.7589
Sonoma County	3,221	1,687,425	0.7041	2,763	1,447,200	0.7275
Stockton NCS*	3,200	1,147,360	0.4820	3,192	1,144,627	0.4980
Terra-Bella*	673	378,906	0.7569	150	84,729	0.7821
Tracy Defence Depot*	3,681	1,390,326	0.5077	3,180	1,201,344	0.5246
Travis AFB	12,970	6,738,871	0.6983	13,200	6,858,000	0.7216
Travis Wherry*	1,421	676,619	0.6402	1,192	567,842	0.6615
Travis AFB Medical Center	4,082	2,235,000	0.7359	3,945	2,160,000	0.7604
Trinity County PUD*	14,177	7,126,982	0.6757	16,457	8,272,882	0.6982
Tuolomne Public Power	5,033	1,838,660	0.4910	5,432	1,984,320	0.5074
Turlock ID	2,547	1,400,856	0.7392	2,859	1,572,004	0.7638
UC Davis	22,838	11,490,701	0.6763	22,720	11,431,728	0.6988
Ukiah, Scheduled	6,173	3,501,305	0.7624	6,173	3,394,417	0.7637
Vacaville*	1,780	897,916	0.6780	1,660	837,419	0.7006
West Stanislaus ID*	509	165,231	0.4363	837	271,670	0.4508
Westlands PP 6-1	428	133,240	0.4187	73	22,745	0.4326
Westlands PP 7-1*	3	939	0.4368	7	2,259	0.4513
Westlands WD*	32	11,137	0.4685	31	10,763	0.4841
Westside ID*	423	168,403	0.5356	82	32,863	0.5534
TOTAL	1,255,226	537,749,167	0.5758	1,268,144	613,326,339	0.6717

	DECEMBER			JANUARY		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Plumas-Sierra, Scheduled	12,902	6,248,319	0.6509	13,726	6,248,319	0.6119
Provident ID*	208	92,395	0.5977	0	0	#DIV/0!
Rag Gulch WD*	147	57,753	0.5285	0	193	0.5285
RD 2035*	196	39,780	0.2730	137	27,814	0.2730
Redding, Scheduled	85,000	44,059,000	0.6967	74,000	38,477,000	0.6989
Roseville, Scheduled	44,700	22,623,292	0.6803	44,700	22,623,292	0.6803
San Juan Suburban	628	304,854	0.6522	244	118,575	0.6522
San Luis - Fitjie*	24	8,316	0.4564	71	24,118	0.4564
San Luis - Kaljian*	11	4,017	0.4833	9	3,289	0.4833
Santa Clara Valley*	758	415,111	0.7361	579	317,306	0.7361
Santa Clara, Scheduled	134,671	56,577,220	0.5647	134,111	63,649,373	0.6379
Sharpe Depot	4,021	1,839,168	0.6148	3,956	1,809,408	0.6148
Shasta Lake, City of, Scheduled	11,450	5,986,441	0.7027	11,450	5,986,441	0.7027
Sierra Conservation*	2,014	1,090,088	0.7276	2,000	1,082,676	0.7276
Site 300	2,681	1,525,200	0.7647	2,550	1,450,800	0.7647
SLAC	33,201	20,832,000	0.8434	49,182	30,859,353	0.8434
SMUD	361,000	219,163,467	0.8160	361,000	197,247,121	0.7344
Sonoma County	3,025	1,584,720	0.7041	2,748	1,439,640	0.7041
Stockton NCS*	3,432	1,230,524	0.4820	3,614	1,295,977	0.4820
Terra-Bella*	79	44,586	0.7569	152	85,705	0.7569
Tracy Defence Depot*	3,684	1,391,616	0.5077	3,618	1,366,667	0.5077
Travis AFB	13,859	7,200,443	0.6983	13,604	7,068,000	0.6983
Travis Wherry*	1,550	738,468	0.6402	1,509	718,929	0.6402
Travis AFB Medical Center	4,077	2,232,000	0.7359	4,077	2,232,000	0.7359
Trinity County PUD*	17,548	8,821,578	0.6757	16,781	8,435,821	0.6757
Tuolomne Public Power	6,473	2,364,432	0.4910	5,735	2,095,104	0.4910
Turlock ID	2,898	1,593,463	0.7392	2,986	1,642,085	0.7392
UC Davis	23,981	12,065,917	0.6763	24,149	12,150,294	0.6763
Ukiah, Scheduled	6,173	3,504,194	0.7630	5,421	2,799,311	0.6941
Vacaville*	1,774	895,172	0.6780	1,820	917,888	0.6780
West Stanislaus ID*	460	149,307	0.4363	522	169,491	0.4363
Westlands PP 6-1	10	3,047	0.4187	26	7,998	0.4187
Westlands PP 7-1*	15	4,996	0.4368	17	5,376	0.4368
Westlands WD*	101	35,292	0.4685	574	199,967	0.4685
Westside ID*	7	2,877	0.5356	66	26,289	0.5356
TOTAL	1,222,120	618,223,599	0.6799	1,233,476	609,687,370	0.6644

APPENDIX C

Total Projected Capacity Energy
Load Forecast

	FEBRUARY			MARCH			APRIL			MAY		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Plumas-Sierra,Scheduled	17,248	7,636,834	0.6589	5,963	3,471,288	0.7824	4,879	3,471,288	0.9883	5,963	3,471,288	0.7824
Provident ID*	0	0	#DIV/0!	0	0	#DIV/0!	236	105,142	0.6176	847	376,771	0.5977
Rag Gulch WD*	254	99,807	0.5851	368	144,768	0.5285	397	156,275	0.5461	1,077	423,522	0.5285
RD 2035*	280	56,963	0.3022	130	26,336	0.2730	167	33,956	0.2821	1,167	236,919	0.2730
Redding, Scheduled	70,000	32,728,000	0.6957	68,000	35,387,000	0.6995	67,000	33,693,000	0.6984	63,000	32,765,000	0.6990
Roseville, Scheduled	44,700	22,623,292	0.7531	43,848	19,795,380	0.6068	36,044	19,795,380	0.7628	35,827	22,623,292	0.8487
San Juan Suburban	204	99,187	0.7221	191	92,628	0.6522	0	0	#DIV/0!	0	0	#DIV/0!
San Luis - Fitjie*	65	22,201	0.5053	133	45,242	0.4564	120	40,766	0.4716	1,533	520,627	0.4564
San Luis - Kaljian*	12	4,343	0.5350	9	3,310	0.4833	9	3,313	0.4994	12	4,140	0.4833
Santa Clara Valley*	488	267,221	0.8149	554	303,185	0.7361	912	499,454	0.7606	1,107	606,504	0.7361
Santa Clara, Scheduled	125,903	42,432,915	0.5015	107,976	42,432,915	0.5282	107,433	35,360,763	0.4571	107,451	42,432,915	0.5308
Sharpe Depot	3,574	1,634,774	0.6807	4,035	1,845,566	0.6148	3,382	1,546,785	0.6353	3,572	1,633,824	0.6148
Shasta Lake, City of, Scheduled	11,450	5,986,441	0.7780	11,450	5,387,797	0.6325	11,450	5,387,797	0.6535	10,870	5,387,797	0.6662
Sierra Conservation*	1,783	965,034	0.8056	1,933	1,046,484	0.7276	1,843	997,925	0.7519	2,147	1,162,452	0.7276
Site 300	2,243	1,275,960	0.8467	2,401	1,365,984	0.7647	2,205	1,254,439	0.7902	2,157	1,227,005	0.7647
SLAC	38,076	23,891,112	0.9337	44,966	28,214,266	0.8434	47,258	29,651,999	0.8715	45,528	28,566,944	0.8434
SMUD	361,000	197,247,121	0.8131	361,000	197,247,121	0.7344	361,000	197,247,121	0.7589	361,000	153,414,427	0.5712
Sonoma County	2,810	1,471,680	0.7795	2,386	1,249,920	0.7041	2,944	1,542,255	0.7275	3,345	1,752,120	0.7041
Stockton NCS*	3,086	1,106,746	0.5336	3,245	1,163,723	0.4820	2,979	1,068,248	0.4980	3,060	1,097,307	0.4820
Terra-Bella*	192	107,875	0.8380	408	230,002	0.7569	1,134	638,494	0.7821	1,688	950,391	0.7569
Tracy Defence Depot*	3,334	1,259,239	0.5621	3,708	1,400,703	0.5077	4,191	1,583,211	0.5246	4,051	1,530,378	0.5077
Travis AFB	12,845	6,673,656	0.7732	13,403	6,963,840	0.6983	13,481	7,003,973	0.7216	12,500	6,494,517	0.6983
Travis Wherry*	1,350	643,182	0.7088	1,478	704,105	0.6402	1,290	614,308	0.6615	1,495	712,094	0.6402
Travis AFB Medical Center	3,682	2,016,000	0.8147	4,077	2,232,000	0.7359	3,940	2,157,000	0.7604	4,077	2,232,000	0.7359
Trinity County PUD*	13,859	6,967,237	0.7481	15,645	7,864,959	0.6757	13,855	6,964,759	0.6982	13,939	7,006,959	0.6757
Tuolomne Public Power	5,008	1,829,520	0.5436	6,380	2,330,580	0.4910	4,965	1,813,678	0.5074	5,273	1,926,216	0.4910
Turlock ID	2,668	1,467,203	0.8183	2,974	1,635,455	0.7392	2,633	1,448,079	0.7638	2,476	1,361,405	0.7392
UC Davis	22,539	11,340,274	0.7487	23,813	11,981,540	0.6763	21,230	10,681,974	0.6988	22,304	11,222,146	0.6763
Ukiah, Scheduled	4,400	2,097,317	0.7093	2,179	1,123,769	0.6931	1,735	863,771	0.6916	1,626	823,327	0.6807
Vacaville*	1,577	795,501	0.7507	1,763	889,396	0.6780	1,794	904,905	0.7006	1,890	953,502	0.6780
West Stanislaus ID*	135	43,943	0.4830	361	117,261	0.4363	3,103	1,007,004	0.4508	5,064	1,643,554	0.4363
Westlands PP 6-1	338	105,308	0.4635	400	124,683	0.4187	720	224,414	0.4326	1,001	311,959	0.4187
Westlands PP 7-1*	474	154,120	0.4836	3,981	1,293,681	0.4368	4,732	1,537,602	0.4513	14	4,563	0.4368
Westlands WD*	1,979	689,914	0.5187	994	346,496	0.4685	1,573	548,200	0.4841	2,332	812,768	0.4685
Westside ID*	63	24,927	0.5930	38	15,201	0.5356	1,143	455,429	0.5534	2,226	887,086	0.5356
TOTAL	1,152,967	541,880,770	0.6994	1,109,191	535,291,982	0.6487	1,111,162	526,965,308	0.6587	1,133,807	509,492,952	0.6040

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APPENDIX C

Total Projected Capacity Energy
Load Forecast

	JUNE			JULY			AUGUST			SEPTEMBER		
	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor	Capacity (kW)	Energy (kWh)	Load Factor
Plumas-Sierra,Scheduled	5,746	3,471,288	0.8390	12,467	6,942,576	0.7485	16,436	7,636,834	0.6245	13,476	6,942,576	0.7155
Provident ID*	767	340,974	0.6176	847	376,578	0.5977	567	252,321	0.5977	62	27,525	0.6176
Rag Gulch WD*	1,175	462,024	0.5461	1,469	577,530	0.5285	1,567	616,032	0.5285	1,137	447,120	0.5461
RD 2035*	1,143	232,055	0.2821	1,738	353,056	0.2730	1,491	302,857	0.2730	139	28,317	0.2821
Redding, Scheduled	86,000	37,702,000	0.6089	53,000	23,468,000	0.5952	58,000	22,661,000	0.5251	29,000	9,485,000	0.4543
Roseville, Scheduled	44,700	25,451,203	0.7908	44,700	25,451,203	0.7653	44,700	25,451,203	0.7653	44,700	25,451,203	0.7908
San Juan Suburban	0	0	#DIV/0I	345	167,400	0.6522	1,342	651,000	0.6522	1,229	596,160	0.6739
San Luis - Fitjie*	3,149	1,069,224	0.4716	3,576	1,214,198	0.4564	1,384	469,787	0.4564	105	35,546	0.4716
San Luis - Kaljian*	996	358,110	0.4994	2,062	741,475	0.4833	905	325,550	0.4833	7	2,483	0.4994
Santa Clara Valley*	998	546,486	0.7606	1,134	620,944	0.7361	1,162	636,145	0.7361	1,088	595,765	0.7606
Santa Clara, Scheduled	131,540	56,577,220	0.5974	188,211	84,865,830	0.6061	195,356	84,865,830	0.5839	188,528	84,865,830	0.6252
Sharpe Depot	3,613	1,652,544	0.6353	4,279	1,957,241	0.6148	4,379	2,002,848	0.6148	4,212	1,926,720	0.6353
Shasta Lake, City of, Scheduled	6,382	3,591,865	0.7817	6,380	3,591,865	0.7567	7,040	3,591,865	0.6858	11,000	5,387,797	0.6803
Sierra Conservation*	2,013	1,089,613	0.7519	2,114	1,144,472	0.7276	2,108	1,141,123	0.7276	2,065	1,117,800	0.7519
Site 300	2,060	1,171,800	0.7902	2,191	1,246,460	0.7647	2,242	1,275,439	0.7647	2,052	1,167,696	0.7902
SLAC	50,315	31,570,398	0.8715	54,522	34,209,797	0.8434	50,587	31,741,049	0.8434	44,876	28,157,382	0.8715
SMUD	361,000	175,330,774	0.6746	361,000	175,330,774	0.6528	361,000	175,330,774	0.6528	361,000	175,330,774	0.6746
Sonoma County	2,804	1,468,800	0.7275	3,260	1,707,480	0.7041	3,601	1,886,040	0.7041	3,093	1,620,000	0.7275
Stockton NCS*	3,240	1,161,953	0.4980	3,286	1,178,161	0.4820	3,608	1,293,667	0.4820	3,336	1,196,046	0.4980
Terra-Bella*	1,881	1,059,356	0.7821	1,926	1,084,362	0.7569	1,608	905,734	0.7569	1,232	693,930	0.7821
Tracy Defence Depot*	3,816	1,441,366	0.5246	4,013	1,515,747	0.5077	4,106	1,550,861	0.5077	3,817	1,442,037	0.5246
Travis AFB	10,957	5,692,950	0.7216	11,322	5,882,715	0.6983	11,322	5,882,715	0.6983	11,396	5,920,668	0.7216
Travis Wherry*	1,380	657,266	0.6615	1,381	657,614	0.6402	1,392	663,004	0.6402	1,380	657,266	0.6615
Travis AFB Medical Center	3,945	2,160,000	0.7604	4,077	2,232,000	0.7359	4,077	2,232,000	0.7359	3,945	2,160,000	0.7604
Trinity County PUD*	13,682	6,878,221	0.6982	14,853	7,466,757	0.6757	15,112	7,597,060	0.6757	15,422	7,752,793	0.6982
Tuolomne Public Power	5,180	1,892,160	0.5074	5,062	1,849,212	0.4910	7,128	2,604,000	0.4910	6,396	2,336,400	0.5074
Turlock ID	2,232	1,227,660	0.7638	2,431	1,337,094	0.7392	2,460	1,352,565	0.7392	2,337	1,285,407	0.7638
UC Davis	22,071	11,105,107	0.6988	22,807	11,475,277	0.6763	22,472	11,306,523	0.6763	21,260	10,696,831	0.6988
Ukiah, Scheduled	2,168	1,083,325	0.6940	5,421	2,799,311	0.6941	6,173	3,507,083	0.7636	6,173	3,391,529	0.7631
Vacaville*	2,025	1,021,371	0.7006	2,352	1,186,632	0.6780	2,422	1,222,053	0.6780	2,094	1,056,321	0.7006
West Stanislaus ID*	3,137	1,018,092	0.4508	4,854	1,575,502	0.4363	2,827	917,464	0.4363	1,503	487,733	0.4508
Westlands PP 6-1	1,629	507,384	0.4326	1,717	534,750	0.4187	1,064	331,508	0.4187	297	92,484	0.4326
Westlands PP 7-1*	3,053	992,006	0.4513	0	0	#DIV/0I	3	1,098	0.4368	1	443	0.4513
Westlands WD*	4,703	1,639,336	0.4841	5,037	1,755,581	0.4685	4,860	1,693,981	0.4685	285	99,354	0.4841
Westside ID*	2,124	846,249	0.5534	2,327	927,128	0.5356	1,629	648,990	0.5356	1,149	457,921	0.5534
TOTAL	1,190,948	557,228,665	0.6498	1,312,068	625,324,640	0.6406	1,345,342	633,534,879	0.6329	1,261,018	591,486,965	0.6515

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APPENDIX C

Total Projected Capacity Energy Load Forecast

	Capacity (kW)	TOTAL Energy (kWh)	Load Factor	
Plumas-Sierra,Scheduled	137,342	69,425,762	0.6925	68,525,763
Provident ID*	3,900	1,734,241	0.6092	
Rag Gulch WD*	8,415	3,308,553	0.5386	
RD 2035*	7,394	1,501,745	0.2782	
Redding, Scheduled	825,000	396,866,000	0.6590	396,889,000
Roseville, Scheduled	518,019	282,791,148	0.7478	
San Juan Suburban	5,735	2,782,804	0.6647	
San Luis - Fitjie*	10,234	3,474,993	0.4651	
San Luis - Kaljian*	4,049	1,455,772	0.4925	
Santa Clara Valley*	10,518	5,759,854	0.7502	
Santa Clara, Scheduled	1,725,016	707,215,252	0.5616	866,188,251
Sharpe Depot	46,310	21,182,094	0.6266	
Shasta Lake, City of, Scheduled	121,575	59,864,414	0.6745	
Sierra Conservation*	23,898	12,937,697	0.7416	
Site 300	27,305	15,535,465	0.7794	
SLAC	556,433	349,135,698	0.8595	
SMUD	4,332,000	2,191,634,675	0.6930	2059,634,675
Sonoma County	36,000	18,857,280	0.7176	
Stockton NCS*	39,278	14,084,340	0.4912	
Terra-Bella*	11,124	6,264,069	0.7714	
Tracy Defence Depot*	45,198	17,073,494	0.5175	
Travis AFB	150,859	78,380,348	0.7117	
Travis Wherry*	16,819	8,010,699	0.6525	
Travis AFB Medical Center	48,000	26,280,000	0.7500	
Trinity County PUD*	181,331	91,156,009	0.6886	
Tuolomne Public Power	68,066	24,864,282	0.5004	
Turlock ID	31,501	17,323,276	0.7533	
UC Davis	272,184	136,948,312	0.6892	
Ukiah, Scheduled	53,814	28,888,659	0.7354	
Vacaville*	22,951	11,578,075	0.6911	
West Stanislaus ID*	23,311	7,566,253	0.4446	
Westlands PP 6-1	7,703	2,399,520	0.4267	
Westlands PP 7-1*	12,300	3,997,083	0.4452	
Westlands WD*	22,500	7,842,790	0.4775	
Westside ID*	11,276	4,493,363	0.5459	
TOTAL	14,595,468	6,900,169,638	0.6476	

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APPENDIX D

Low Power Factor Charge Documentation

APPENDIX D

Low Power Factor Charge Documentation

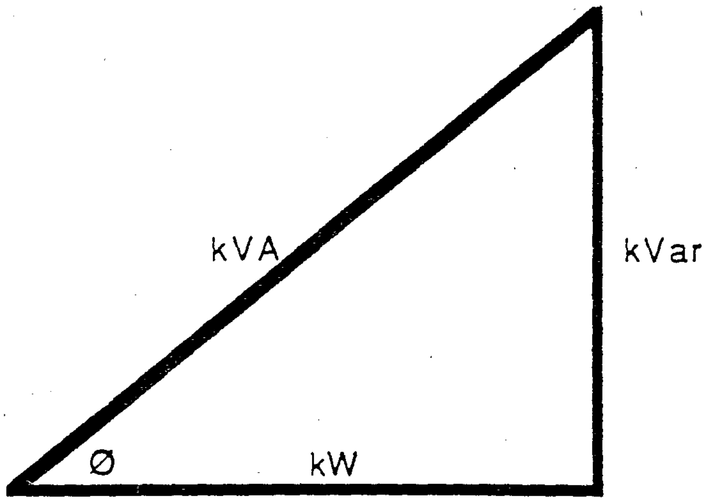
A. kvar/kW Multiplier Factor

A set of kVar/kW multipliers have been developed to simplify calculation of the LPF charge. The kVar/kW multiplier is the kVar/kW ratio which when multiplied by the customer's peak demand equals the kilovars required to raise the customer's power factor to 95 percent.

Kvars = (kVar/kW Multiplier)(Maximum Demand)
LPF Charge = (kVar/kW Factor)(Demand)($ per kVar Charge)

Calculated Power Factor (%)	kVar/kW Multiplier
95	0
94	0.04088
93	0.06655
92	0.09733
91	0.12693
90	0.15564
89	0.18365
88	0.21106
87	0.23806
86	0.26463
85	0.29106
84	0.31726
83	0.34333
82	0.36932
81	0.39531
80	0.42132
79	0.44740
78	0.47360
77	0.49995
76	0.52648
75 and below	0.55323

The kVar/kW multipliers were developed using the following relationships for 100,000 kW. Although the kVar/kW multiplier was developed using an assumed demand of 100,000 kW, the multiplier can be used with any demand to caluculate LPF Charge kVars.



$$\cos Ø = \text{POWER FACTOR}$$

$$= \frac{kW}{kVA}$$

$$(kVA)^2 = (kW)^2 + (kVar)^2$$

$$kVA = \sqrt{(kW)^2 + (kVar)^2}$$

$$kVA = \frac{kW}{\text{POWER FACTOR}}$$

$$kW = \sqrt{(kVA)^2 - (kVar)^2}$$

$$kVars = \sqrt{(kVA)^2 - (kW)^2}$$

Example Calculation:

Average P. F. = 85%

Step 1

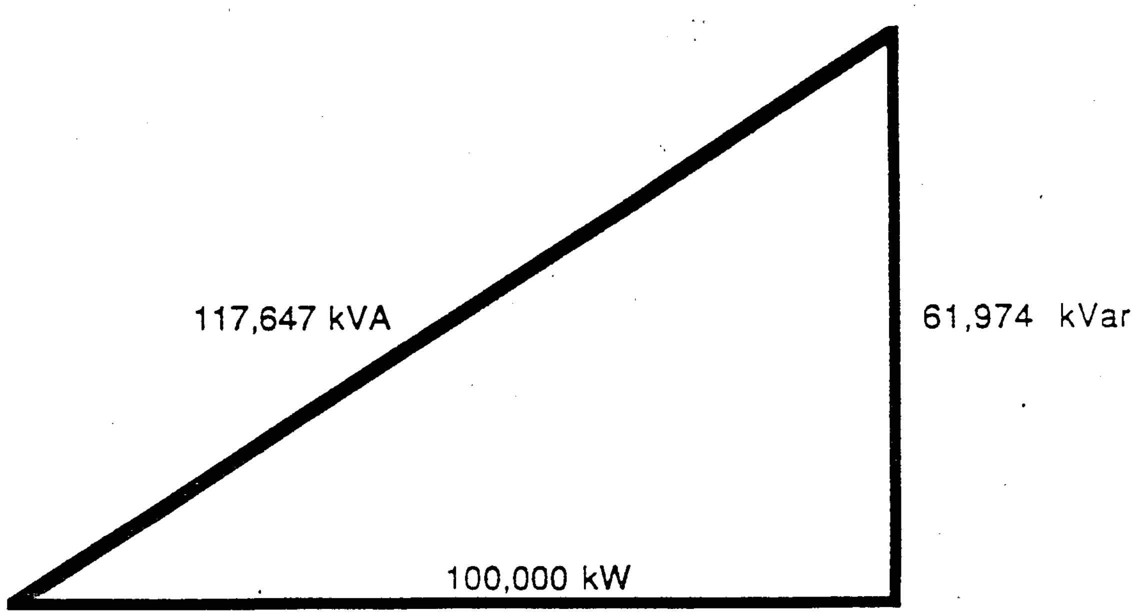
Demand = 100,000 kW ← Demand

Volt-Amps = $\frac{100,000}{0.85}$

= 117,647 kVA ← kVA

Reactive Volt-Amps = $\sqrt{(117,647)^2 - (100,000)^2}$

= 61,974 kVar ← kVar



B. Examples of Application

Formula 1: Calculated Power Factor =
(Average Monthly Power Factor) + (Peak Monthly Power Factor)/2

Formula 2: LPF Charge =
(Demand)(kVar/kW Factor)(LPF $ Rate)

LPF $ Rate: $2.50

Example 1:

Assume:
1. Maximum Demand = 10,000 kW
2. Average Monthly Power Factor = 89%
3. Peak Monthly Power Factor = 94%

Calculated Power Factor =

$$\frac{89\% + 94\%}{2} = 91.5\%$$

Rounded to 92%

LPF Charge = (10,000)(0.09733*)(2.50) = $2,433.25

*From kVar/kW Factor Table for 92% Load Factor

Example 2:

Assume:
1. Maximum Demand = 2,000 kW
2. Average Monthly Power Factor = 91%
3. Peak Monthly Power Factor = 99%

Calculated Power Factor =

$$\frac{91\% + 95\%^{*}}{2} = 93\%$$

*No credit for power factor greater than 95%

LPF Charge = (2,000)(0.06655*)(2.50) = $332.75

*From kVar/kW Factor Table for 93%

Example 3:

Assume:
1. Maximum Demand = 1,000 kW
2. Average Monthly Power Factor = 67%
3. Peak Monthly Power Factor = 80%

Calculated Power Factor =

$$\frac{67\% + 80\%}{2} = 73.5\%$$

Rounded to 74%

LPF Charge = (1,000)(0.55323*)(2.50) = $1,383.08

*From kVar/kW Factor Table for 75% or less load factor

APPENDIX E

Revenue Adjustment Clause (RAC) Methodology

APPENDIX E

Revenue Adjustment Clause (RAC) Methodology

The following methodology shall be used for the revenue adjustment clause (RAC) calculation:

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

   ANR > PNR ; C = ANR - PNR

   Where:

   ANR = Actual Net Revenue

   PNR = Projected Net Revenue

   C = Credit

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

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

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

   Where:

   ANR = Actual Net Revenue

   PNR = Projected Net Revenue

   MIP = Minimum Investment Payment

   AD = Annual Deficit

   S = Surcharge

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

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

Where:

ANR = Actual Net Revenue

PNR = Projected Net Revenue

MIP = Minimum Investment Payment

S = Surcharge

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

3. The maximum RAC credit allocation will equal $20 million plus the amount of the Pacific Gas and Electric Company refund credit applied to Western power bills for the fiscal year. The maximum allocation for a RAC surcharge shall not exceed $20 million.

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

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

5.1 Actual Net Revenue - The Recorded Net Revenue.

5.2 Annual Deficit - The amount the 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 prior fiscal year that the RAC is being calculated, or the projected net revenue.

5.4 Projected Net Revenue - The annual net revenue available for investment repayment projected in the PRS for the rate case during the fiscal year that the RAC is being calculated as follows:

Period	Projected Net Revenue
October 1, 1997 - September 30, 1998	$5,061,186
October 1, 1998 - September 30, 1999	$8,924,591
October 1, 1999 - September 30, 2000	$11,799,331
October 1, 2000 - September 30, 2001	$16,400,379
October 1, 2001 - September 30, 2002	$28,541,791

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.

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

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

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

APPENDIX F

Power Scheduling Service Rate Methodology

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APPENDIX F

Power Scheduling Service Rate Methodology

PROPOSED RATE FOR CVP POWER SCHEDULING SERVICE

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

Two Cost Components:

1. Hourly Cost for Dispatcher and/or Scheduler Resource:	$ 68.00	per hour
2. Hourly Cost for Phone System Equipment:	$ 5.80	per hour
Proposed Rate for Power Scheduling Service:	**$ 73.80**	**per hour**

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APPENDIX F

Power Scheduling Service Rate Methodology

Calculations for the estimated 5-yr average hourly dispatch rate for FY98-FY2002 period
Reference: FY 1997 Labor Hour Rates as of November 4, 1996

Escalation Rate @2.52% per year for FY 1998 - 2002

Fiscal Year	Annual Salary	Hourly Base	Additives 19.94%	Leave 18%	Hourly Subtotal	O&M Overhead	Total O&M Hourly
estimated 1997	63,302	30.33	6.05	6.55	42.93	20.08	63.01
1998	64,897	31.10	6.20	6.71	44.01	20.59	64.60
1999	66,533	31.88	6.36	6.88	45.12	21.10	66.22
2000	68,209	32.68	6.52	7.06	46.26	21.64	67.89
2001	69,928	33.51	6.68	7.23	47.42	22.18	69.60
2002	71,690	34.35	6.85	7.42	48.62	22.74	71.36
							67.93
Average 1998 - 2002 Hourly Rate						rounded	**68.00**

APPENDIX F

Power Scheduling Service Rate Methodology

Operating Equipment Cost for Power Scheduling Service

		Short Life Equipment	Total Annual Cost	
"V" - Band Phone System		$250,000.00	$35,388.99	Amortized over 10 yrs @ 6.875%
Equipment & Installation Cost for Meter & High Voltage Instrument Transformers		$102,500.00	$14,509.48	Amortized over 10 yrs @ 6.875%
Annual O & M			$1,000.00	Direct labor cost
Number of Hour per Year:	8,760			
Subtotal		$352,500.00	**$50,898.47**	

Annual Per Hour Equipment Cost	**$5.81**
rounded	**$5.80**

APPENDIX G

CVP Firm and Non-Firm Transmission Service

Rate Calculations

APPENDIX G

Development of the Proposed CVP Firm and Non-Firm Transmission Service Rates

The CVP transmission service rate is calculated using a cost-of-service (COS) study. Data used in the COS were obtained from Western's *Results of Operations* as of September 30, 1995 (FY 1995), the Bureau of Reclamation's (Reclamation) FY 1995 *Financial Statement*, related FY 1995 and FY 1996 financial reports, and projected investment. The base O&M expenses used for transmission lines and substations are from Western and Reclamation's FY 1995 financial reports, and Western's non-facility specific O&M expenses were updated using Western's FY 1996 financial reports. All O&M expenses were escalated at 3.5% for the five-year rate period.

The *Results of Operations* yields an annual investment balance for each transmission system facility. The balance is analogous to the assets associated with the facilities owned and used by Western. The investment balance includes the original cost of construction of the facility, plus the cost of any additions, replacements, and if necessary, any prior-year adjustments, and any Reclamation costs. The annualized investment payment is determined by calculating the amount due over a fifty-year period and associated annual interest expense.

O&M costs not associated with specific facilities were allocated to transmission based on a percentage calculated by dividing Western's direct labor charges (DLC) for transmission facilities to the sum of Reclamation's DLC for generation facilities, and Western's DLC for transmission and generation facilities. For Reclamation's DLC only those charges associated with generation facilities directly connected to the CVP transmission system were used. The amounts used in the development of the resulting percentage are shown below:

$$\frac{\text{Western's DLC for Transmission}}{\text{Reclamation's DLC for Generation} + \text{Western's DLC for Transmission} + \text{Western's DLC for Generation}} =$$

$$\frac{\$1{,}036{,}774}{(\$1{,}299{,}395 + \$1{,}036{,}774 + \$1{,}755{,}682)} = 25\%$$

The denominator used in the proposed firm transmission rate calculation is the amount of transmission capacity on the CVP transmission system. The amount of transmission capacity is the sum of the installed capacity of the CVP northern powerplants (less station service) plus a projected five-year average transmission rate of delivery (TRD) under contract during the time of the rate adjustment period.

CVP Installed Capacity for Northern Powerplants

J.F. Carr	154,000	kW			
Folsom	215,000	kW			
Keswick	105,000	kW			
Nimbus	14,000	kW			
Shasta	578,000	kW			
Spring Creek	200,000	kW			
Trinity	140,000	kW			
Total	1,406,000	kW			
less station service	(1,500)	kW			
Total Capacity	1,404,500	kW	X 12 months	=	16,854,000 kW-month
Associated Energy	1,404,500	kW	X 8,760 hours	=	12,303,420,000 kWh

Transmission Rate of Delivery

5-Year Annual Average

City of Redding	121,400	kW-month			
City of Roseville	175,470	kW-month			
SMUD	341,000	kW-month			
City of Shasta Lake	8,000	kW-month			
Total	645,870	kW	X 12 months	=	7,750,440 kW-months
Associated Energy	645,870	kW	X 8,760 hours	=	5,657,821,200 kWh

Total Transmission Capacity (kW) = **24,604,440**

Total Associated Energy (kWh) = **17,961,241,200**

Calculation of Proposed CVP Firm Transmission Service Rate

$$\text{Proposed CVP Firm Transmission Service Rate} = \frac{\text{Total Annual Revenue Requirement}}{\text{Total Transmission Capacity}}$$

$$= \frac{\$11{,}918{,}369}{24{,}604{,}440 \text{ kW-month}}$$

$$= \mathbf{\$0.48/kW\text{-}month}$$

Calculation of Proposed CVP Non-Firm Transmission Service Rate

$$\text{Proposed CVP Non-Firm Transmission Service Rate} = \frac{\text{Total Annual Revenue Requirement}}{\text{Total Transmission Capacity} * 8{,}760 \text{ hours}}$$

$$= \frac{\$11{,}918{,}369}{17{,}961{,}241{,}200 \text{ kWh}}$$

$$= \mathbf{1.00\ mill/kWh} \text{ (rounded to nearest mill/kWh)}$$

Plant-In-Service
Transmission Facilities

Transmission Line	Percentage Transmission
Western:	
Carr-Keswick No. 1	0%
Carr-Keswick No. 2	0%
Cottonwood-Elverta No. 2	100%
Cottonwood-Elverta No. 3	100%
Cottonwood-Tracy	100%
Elverta-Tracy 230-kV No. 1	100%
Elverta-Tracy 230-kV No. 2	100%
Folsom-Elverta	0%
Folsom-Nimbus	0%
Friant Dam & Camp	0%
Keswick-Cottonwood No. 2	100%
Keswick-Co[illegible]nwood No. 3	100%
Keswick-E[illegible]	100%
Tracy-Live[illegible] 230-kV	100%
Roseville-E[illegible] No. 2	100%
Spring Cree[illegible]wick	0%
Shasta-Cotto[illegible]d	0%
Shasta-Kesw[illegible] 230-kV	0%
Shasta-Tracy [1]	100%
Trinity-Carr	0%
Tracy-Ygnacio	0%
Malin-Round Mountain No. 1	0%
Round Mountain-Cottonwood [2]	0%
Olinda-Tracy [2]	27%
Reclamation:	
Shasta-Toyon	0%
Shasta Service Line	0%
Shasta-Tracy	100%
Carr Standby	0%
Spring Creek 13.8-kV Standby	0%

Total Plant-In-Service Transmission Investment: **$58,275,010**

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[1] Now part of Olinda-Tracy

[2] These percentage allocations are incorrect. They should be 100%.

Plant-In-Service
Switchyard and Substation Facilities

Switchyard/Substation	Percentage Transmission
Western:	
J.F. Carr Substation	0%
Clayton Substation	0%
Contra Costa	0%
Corning P.P.	0%
Coyote Substation	0%
Cottonwood Substation	71%
Cottonwood Substation (Intertie) [1]	71%
Dos Amigos	0%
Elverta Substation	100%
Folsom Substation	0%
Keswick Substation 230-kV	27.3%
Keswick Substation 115-kV	0%
Lewiston Substation	0%
Lawrence Livermore Laboratory Substation [1]	100%
New Melones Substation	0%
Nimbus	0%
O'Neill	0%
Pacheco Substation	0%
Pleasant Valley	0%
San Luis	0%
Shasta Substation	0%
Spring Creek	0%
Tracy Substation (230-kV)	60%
Tracy Substation (500-kV) [1]	27%
Trinity	0%
Whiskeytown Substation	0%
Wintu Pumping Plant Switchyard	0%
Ygnacio Pumping Plant Switchyard	0%
Malin Substation	0%
Round Mountain Substation	0%
Reclamation:	
Keswick 230-kV Switchyard	27.3%
Keswick 115-kV Switchyard	0%
Carrier Current Equipment -- Shasta	0%
Folsom Switchyard	0%
Nimbus Switchyard	0%
Carrier Current Equipment -- Folsom	0%
Tracy Switchyard	60%
Carrier Current Equipment -- Tracy	60%
Shasta 230-kV Switchyard	0%
Trinity Switchyard	0%
Spring Creek Switchyard	0%
San Luis Switchyard	0%
Dos Amigos Switchyard	0%
O'Neill Pumping Plant Switchyard	0%
Los Banos Substation	0%
Pacheco Substation	0%

Total Plant-In-Service Switchyard and Substation Facilities: $24,158,382

The allocation for substation and switchyard facility costs were based on the number of power circuit breakers at the substation used to serve transmission cost elements versus the number of breakers used to serve generation cost elements. If two breakers control a single element, that element received twice the weight. Breakers that serve elements not owned by Western were not considered in the allocation.

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1 These percentage allocations are incorrect. Lawrence Livermore Laboratory Substation is allocated differently between 230-kV (100%), 115-kV (50%), and 13.8-kV (0%); Cottonwood Substation (Intertie) and Tracy Substation (500-kV) should have been assigned 0%.

Plant-In-Service
Miscellaneous Facilities

Facility	Percentage Transmission
Mt. Oso Microwave	90%
Elverta Microwave Building	71%
Grapevine Pass Microwave	90%
Sacramento Microwave	90%
Sacramento Dispatch Office	25%
Southfork Mountain Microwave	90%
Sacramento Area Operations Center	25%
Elverta Maintenance Facility	71%
Tracy Maintenance Facility	5%
Redding Maintenance Facility	40%

Total Plant-In-Service Miscellaneous Facilities **$6,750,573**

APPENDIX H

COTP Firm and Non-Firm Transmission Service

Rate Calculations

APPENDIX H

Development of Proposed COTP Firm and Non-Firm Transmission Service Rates

The COTP transmission service rate is equal to the costs associated with providing transmission service on the COTP system divided by the available transmission capacity on the COTP system.

The annual revenue requirement used to develop the numerator in the proposed COTP firm and non-firm transmission service rates calculations are described below:

Long-Term Capacity Rights: Western purchased rights to 50 MW of long-term capacity on the COTP transmission system. The capital costs incurred for the 50 MW are $15,503,538, which is amortized over a 50-year period at a 9.25% interest rate, resulting in an annual principal payment of $310,000, plus an average annual interest payment of $731,540.

Leased Capacity: Western has two contractual arrangements to lease an additional 73 MW of COTP capacity, under Contract No. 93-SAO-00011, and 27 MW of COTP capacity, under Contract No. 93-SAO-00009, with the Transmission Agency of Northern California (TANC). Based on FY 1996 accounting records, the lease costs associated with the 73 MW of COTP capacity is $2,014,553. These costs are derived from TANC's taxable share of principal and interest, O&M, administrative and general expenses, and, if applicable, additions and betterments. On August 31, 1995, Western gave notice to TANC for termination of Contract No. 93-SAO-00011, to become effective August 31, 1998. The costs associated with the 73 MW were not included in the proposed rates calculations for COTP transmission service beginning in FY 1999.

The 1996 lease costs associated with the 27 MW of COTP capacity from TANC is $331,462. These costs are again derived from TANC's taxable share of COTP costs associated with the 27 MW of COTP capacity.

Scheduling Charges: Scheduling charges are paid to the Pacific Gas and Electric Company (PG&E) for their services as control area operator.

The annual scheduling charges projected in the proposed COTP transmission rates calculations is $5,400.

Facility Charges: Facility charges are paid to PG&E for the costs PG&E incurred to install facilities for the benefit of the COTP participants. This charge includes the ongoing costs of owning, operating, maintaining and replacing such facilities.

The annual facility charges projected in the proposed COTP transmission rates calculations is $11,673.

Layoffs: Under Contract No. 93-SAO-00013, Western has contracted for entitlement to the allocation of COTP transmission capacity from the City of Shasta Lake (Shasta Lake), totaling 15.4 MW. The FY 1996 costs associated with this entitlement are $494,302, which are derived from Shasta Lake's cost responsibility for principal and interest, O&M, administration and general expenses, and capital improvements. Western has given notice to Shasta Lake for the termination of Contract No. 93-SAO-00013, which will become effective August 31, 1998. As with the termination with the TANC contract, the costs associated with the 15.4 MW entitlement of COTP capacity from Shasta Lake will not be included in the proposed rates calculations for COTP transmission service beginning in FY 1999.

Western also receives a one (1) MW layoff from the San Juan Suburban Water District (San Juan). There are no direct costs associated with this layoff.

O&M Costs for Western's use of 100 MW for the Department of Energy (DOE) and the Fish and Wildlife Service (F&WS), and other Federal uses: Costs associated with this 100 MW COTP entitlement are based on a percentage share of O&M expenses. To determine the O&M costs associated with the portion of COTP transmission capability available for use by others, the following formula is used:

> Western's Monthly O&M General Costs minus O&M Costs Associated with 100 MW CVP Segment minus O&M Costs Associated with DOE's Participation

Based on FY 1996:

Western's annual O&M General Costs	=	$728,046
O&M Costs Associated with the 100 MW CVP Segment	=	$330,238
O&M Costs Associated with DOE's Participation	=	$142,298
Remaining Costs	=	$255,509

The denominator for the proposed COTP firm and non-firm transmission service rates is based on the total transmission capability available for use. In FY 1998, Western will have approximately 213.4 MW of COTP transmission capacity. This consists of:

50 MW of long-term capacity
73 MW of leased capacity
27 MW of leased capacity
15.4 MW layoff from the City of Shasta Lake
1 MW layoff from San Juan
47 MW of the 100 MW used for DOE and the F&WS, and other Federal uses

Beginning in FY 1999, after the termination of the 73 MW lease from TANC and the 15.4 MW layoff from Shasta Lake, Western's availability of COTP transmission will be reduced to approximately 125 MW.

Calculation of Proposed COTP Firm Transmission Rate
FY 1998

Proposed COTP Firm Transmission Service Rate	=	Annual Revenue Requirement / Total Transmission Capacity Available
	=	\$4,154,439 / 2,497 MW
	=	**\$1.66/kW-month**

Calculation of Proposed COTP Non-Firm Transmission Rate
FY 1998

Proposed COTP Non-Firm Transmission Service Rate	=	Annual Revenue Requirement / Energy Associated with Total Transmission Capacity Available
	=	\$4,154,439 / 1,822,649 MWh
	=	**2.28 mills/kWh**

Calculation of Proposed COTP Firm Transmission Rate

FY 1999 - FY 2002

Proposed COTP Firm Transmission Service Rate	=	$\dfrac{\text{Annual Revenue Requirement}}{\text{Total Transmission Capacity Available}}$
	=	$\dfrac{\$1{,}645{,}584}{1{,}463 \text{ MW}}$
	=	**$1.12/kW-month**

Calculation of Proposed COTP Non-Firm Transmission Rate

FY 1999 - FY 2002

Proposed COTP Non-Firm Transmission Service Rate	=	$\dfrac{\text{Annual Revenue Requirement}}{\text{Energy Associated with Total Transmission Capacity Available}}$
	=	$\dfrac{\$1{,}645{,}584}{1{,}067{,}625 \text{ MWh}}$
	=	**1.54 mills/kWh**

APPENDIX I

Ancillary Services Rates Methodology

APPENDIX I

Ancillary Services Rate Methodology

Calculation of Average Rates for Regulation Service (FY 1998 - 2002):

ITEM	COSTS
AVERAGE ANNUAL FY 1998-2002 OPERATION & MAINTENANCE EXPENSES - POWER:	$4,390,001
AVERAGE ANNUAL FY 1998-2002 OPERATION & MAINTENANCE EXPENSES - MULTIPURPOSE:	$1,637,137
ANNUAL PRINCIPAL PAYMENT ON PLANT IN SERVICE - POWER:	$2,302,650
AVERAGE ANNUAL INTEREST PAYMENT ON PLANT IN SERVICE - POWER:	$1,761,527
ANNUAL PRINCIPAL PAYMENT ON PLANT IN SERVICE - MULTIPURPOSE:	$2,781,895
AVERAGE ANNUAL INTEREST PAYMENT ON PLANT IN SERVICE - MULTIPURPOSE:	$2,128,150
TOTAL ANNUAL COSTS	**$15,001,361**
MONTHLY COSTS (Total Annual Costs/12)	$1,250,113
CAPACITY (kW) AVAILABLE FROM UNITS FOR REGULATION: (Max. Op. Capacity of 1,706,000 kW multiplied by 60% = to 90% exceedance) Trinity, J.F. Carr, Folsom, Shasta, New Melones, Spring Creek	1,023,600
MONTHLY PER UNIT (kW) COST FOR REGULATION POWERPLANTS: **($1,535,290/1,023,600 kW)**	**$1.221**
MONTHLY DISPATCHER SALARY CHARGE PER KW:	**$0.040**
ESTIMATED COST FOR CONTROL AREA SERVICES EQUIPMENT PER KW:	**$0.125**
TOTAL PER KW MONTHLY CHARGE FOR REGULATION SERVICE: **($1.500 + $0.042 + $0.125)**	**$1.386**
rounded	**$1.39**
Weekly Regulation Service Rate (per kW week)	$0.3192
Daily Regulation Service Rate (per kW day)	$0.0456

APPENDIX I

Ancillary Services Rate Methodology

Estimated Operating Equipment Costs for Control Area Services
(Estimate for Regulation Service)

EQUIPMENT		ANNUAL COST
Sonet System, 672 Channel System Capacity		$1,160,365
Cost for CAT circuits (10)		$5,420
Analog Microwave Radio System, 132 Channels		$437,403
Cost for CAT circuits (6)		$18,498
COTP Digital Microwave System (DMS), Dual Route		
Costs Attributed to CVP System		$180,562
Cost for CAT circuits (3)		$4,239
Leased Circuits		
Cost for 7 leased circuits ($7 x $4,809)		$33,663
Total Annual Costs for CVP System		$1,840,149
CVP Powerplants Output at 90% Exceedence Capacity (kW)		1,230,000
Annual Total Cost Per kW	$	1.50
Monthly Cost Per kW	**$**	**0.125**

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APPENDIX I

Ancillary Services Rate Methodology

Calculation of Average Rates for Spinning Reserve Service (FY 1998 - 2002):

ITEM	COSTS
AVERAGE ANNUAL FY 1998-2002 OPERATION & MAINTENANCE EXPENSES - POWER:	$3,575,134
AVERAGE ANNUAL FY 1998-2002 OPERATION & MAINTENANCE EXPENSES - MULTIPURPOSE:	$996,086
ANNUAL PRINCIPAL PAYMENT ON PLANT IN SERVICE - POWER:	$2,302,650
AVERAGE ANNUAL INTEREST PAYMENT ON PLANT IN SERVICE - POWER:	$1,761,527
ANNUAL PRINCIPAL PAYMENT ON PLANT IN SERVICE - MULTIPURPOSE:	$2,781,895
AVERAGE ANNUAL INTEREST PAYMENT ON PLANT IN SERVICE - MULTIPURPOSE:	$2,128,150
TOTAL ANNUAL COSTS	**$13,545,443**
MONTHLY COSTS (Total Annual Costs/12)	$1,128,787
CAPACITY (kW) AVAILABLE FROM UNITS FOR SPINNING: (Max. Op. Capacity of 1,706,000 kW multiplied by 60% = to 90% exceedance) Trinity, J.F. Carr, Folsom, Shasta, New Melones, Spring Creek	1,023,600
MONTHLY PER UNIT (kW) COST FOR SPINNING: ($1,358,652/1,023,600 kW)	**$1.103**
MONTHLY DISPATCHER SALARY CHARGE PER KW:	**$0.040**
TOTAL PER KW MONTHLY CHARGE FOR SPINNING RESERVE SERVICE: ($1.327 + $0.042)	**$1.143**
rounded	**$1.14**
plus Adder for Purchasing Energy to Motor Unit	+ Market Rate Energy

Weekly Spinning Reserve Service Rate (per kW week)	$0.2688 + Adder
Daily Spinning Reserve Service Rate (per kW day)	$0.0384 + Adder
Hourly Spinning Reserve Service Rate (per kW hour)	$0.0016 + Adder

APPENDIX I

Ancillary Services Rate Methodology

Calculation of Average Rates for Supplemental Reserve Service (FY 1998 - 2002):

ITEM	COSTS
AVERAGE ANNUAL FY 1998-2002 OPERATION & MAINTENANCE EXPENSES - POWER:	$3,575,134
AVERAGE ANNUAL FY 1998-2002 OPERATION & MAINTENANCE EXPENSES - MULTIPURPOSE:	$996,086
ANNUAL PRINCIPAL PAYMENT ON PLANT IN SERVICE - POWER:	$2,302,650
AVERAGE ANNUAL INTEREST PAYMENT ON PLANT IN SERVICE - POWER:	$1,761,527
ANNUAL PRINCIPAL PAYMENT ON PLANT IN SERVICE - MULTIPURPOSE:	$2,781,895
AVERAGE ANNUAL INTEREST PAYMENT ON PLANT IN SERVICE - MULTIPURPOSE:	$2,128,150
TOTAL ANNUAL COSTS	**$13,545,443**
MONTHLY COSTS (Total Annual Costs/12)	$1,128,787
CAPACITY (kW) AVAILABLE FROM UNITS FOR SUPPLEMENTAL: (Max. Op. Capacity of 1,706,000 kW multiplied by 60% = to 90% exceedance) Trinity, J.F. Carr, Folsom, Shasta, New Melones, Spring Creek	1,023,600
MONTHLY PER UNIT (kW) COST FOR SUPPLEMENTAL: ($1,358,652/1,023,600 kW)	**$1.103**
MONTHLY DISPATCHER SALARY CHARGE PER KW:	**$0.040**
TOTAL PER KW MONTHLY CHARGE FOR SUPPLEMENTAL RESERVE SERVICE: ($1.327 + $0.042)	**$1.143**
rounded	**$1.14**

Weekly Supplemental Reserve Service Rate (per kW week)	$0.2688
Daily Supplemental Reserve Service Rate (per kW day)	$0.0384
Hourly Supplemental Reserve Service Rate (per kW hour)	$0.0016

APPENDIX I

Ancillary Services Rate Methodology

Calculation for per kW Charge for Dispatcher Time

Numbers of hours per year 24 hours per day x 365 days	8,760
Dispatcher Hourly Rate for Budget purposes	**$68.00**
Dispatcher Annual Cost	$595,680.00
Dispatcher Monthly Cost	$49,640.00
kW Available per 2004 Marketing Plan	1,230,000
	$0.0404
Monthly Dispatcher Cost per kW	**$0.040** (rounded)