Basin will neither refund nor bill its customers for any amounts under the conditions of Section No. 39.3.1 of its FERC Gas Tariff.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions or protests should be filed on or before October 11, 1995. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party to the proceeding must file a motion to intervene. Copies of the filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 95–24975 Filed 10–6–95; 8:45 am]

BILLING CODE 6717–01–M

Office of Energy Research

DOE/NSF Nuclear Science Advisory Committee Renewal

AGENCY: Office of Energy Research, Department of Energy.

ACTION: Notice of renewal.

SUMMARY: Pursuant to Section 14(a)(2)(A) of the Federal Advisory Committee Act and in accordance with title 41 of the Code of Federal Regulations, section 101–6.1015, and following consultation with the Committee Management Secretariat, General Services Administration, notice is hereby given that the DOE/NSF Nuclear Science Advisory Committee has been renewed for a two-year period beginning in September 1995. The Committee will provide advice to both the Department of Energy and the National Science Foundation on scientific priorities within the field of basic nuclear science research. Basic nuclear science research is understood to encompass experimental and theoretical investigations of the fundamental interactions, properties, and structures of atomic nuclei.

The renewal of the DOE/NSF Nuclear Science Advisory Committee has been determined to be essential to the conduct of the Department's business and in the public interest in connection with the performance of duties imposed upon the Department of Energy by law. The Committee will continue to operate in accordance with the provisions of the Federal Advisory Committee Act, the Department of Energy Organization Act (Pub. L. 95–91), and rules and regulations issued in implementation of those acts.

Further information regarding this advisory committee can be obtained from Rachel Samuel at (202) 586–3279.

Issued in Washington, D.C. on September 22, 1995.

JoAnne Whitman,

Deputy Advisory Committee Management Officer.

[FR Doc. 95–25046 Filed 10–6–95; 8:45 am]

BILLING CODE 6450–01–M

Western Area Power Administration

Central Valley Project Notice of Rate Order No. WAPA–72

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Rate Order—Central Valley Project commercial firm power rate adjustment.

SUMMARY: Notice is given of the confirmation and approval by the Deputy Secretary of the Department of Energy (DOE) of Rate Order No. WAPA–72 and Rate Schedule CV–F8 placing provisional commercial firm power rates for capacity and energy from the Central Valley Project (CVP) of the Western Area Power Administration (Western) into effect on an interim basis. The provisional rates, will remain in effect on an interim basis until the Federal Energy Regulatory Commission (FERC) confirms, approves, and places them into effect on a final basis or until they are replaced by other rates.

The commercial firm power rates will provide sufficient revenue to pay all annual costs including interest expense, plus repayment of required investment within the allowable time period. These rates consist of a capacity rate, energy base rate, and energy tier rate. The energy tier rate is applied to energy at a 70 percent and higher load factor, and is based on the average CVP Northwest energy rate. The load factor is computed based on the lesser of the customer's (1) maximum demand for the month, or if a scheduled customer, the maximum scheduled demand for the month; or (2) the customer's Contract Rate of Delivery (CRD) for commercial firm power.

A comparison of existing and provisional rates follows:

COMPARISON OF EXISTING AND PROVISIONAL RATES

[Commercial Firm Power Rate Schedule]

Effective period	Existing	Provisional	Percent Change
Composite Rate (mills/kWh):			
10/01/95 to 09/30/96	31.55	23.35	(26)
10/01/96 to 09/30/97	31.55	25.00	(21)
10/01/97 to 04/30/98	34.37	26.50	(23)
Capacity Rate ($/kW/month):			
10/01/95 to 09/30/96	6.57	4.03	(39)
10/01/96 to 09/30/97	6.57	4.32	(34)
10/01/97 to 04/30/98	7.16	4.58	(36)
Energy Base Rate (mills/kWh):			
10/01/95 to 09/30/96	17.73	14.83	(16)
10/01/96 to 09/30/97	17.73	15.93	(10)
10/01/97 to 04/30/98	19.33	16.93	(12)
Energy Tier Rate (mills/kWh):			
10/01/95 to 09/30/96	34.70	25.90	(25)
10/01/96 to 09/30/97	34.70	26.27	(24)
10/01/97 to 04/30/98	37.46	26.48	(29)

DATES: Rate Schedule CV–F8 will be placed into effect on an interim basis on October 1, 1995 and will be in effect until FERC confirms, approves, and places the rate schedule in effect on a final basis for a 2½-year period, or until the rate schedule is superseded.

FOR FURTHER INFORMATION CONTACT:

Mr. James C. Feider, Area Manager, Sacramento Area Office, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630, Telephone (916) 353–4418

Mr. Joel K. Bladow, Assistant Administrator for Washington Liaison, Power Marketing Liaison Office, Room 8G–027, Forrestal Building, 1000 Independence Avenue SW., Washington, DC 20585–0001, Telephone (202) 586–5581

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

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

The Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR Part 903, have been followed by Western in the development of these commercial firm power rates. A summary of the steps Western took to ensure involvement of interested parties in the rate process follows:

1. The proposed rate adjustment was initiated on June 9, 1995, when a letter announcing an informal customer meeting was mailed to all commercial firm power customers and interested parties. The meeting was held on June 26, 1995, in Sacramento, California. At this informal meeting, Western explained the rationale for the rate decrease and rate design methodology, and answered questions.

2. A **Federal Register** notice was published on July 10, 1995 (60 FR 35556), officially announcing the commercial firm power rate adjustment, initiating the public consultation and comment period, announcing the public information and public comment forums, and presenting procedures for public participation.

3. On July 17, 1995, letters were mailed from Western's Sacramento Area Office to all commercial firm power customers and interested parties transmitting the **Federal Register** notice of July 10, 1995.

4. On July 19, 1995, a rate brochure was mailed to all commercial firm power customers and interested parties.

5. At the public information forum held on the morning of July 26, 1995, Western explained the rationale for the rate decrease and rate design methodology in greater detail, and answered questions.

6. The comment forum was held on the afternoon of July 26, 1995, to give the public an opportunity to comment for the record. Two customer representatives made oral comments.

7. Eight comment letters were received during the consultation and comment period. The consultation and comment period ended August 11, 1995. All formally submitted comments have been considered in the preparation of this rate order.

Rate Order No. WAPA–72, confirming, approving, and placing the proposed CVP commercial firm power rates into effect on an interim basis, is issued, and the new Rate Schedule CV–F8 will be submitted promptly to FERC for confirmation and approval on a final basis.

Issued in Washington, D.C., September 19, 1995.

Charles B. Curtis,

Deputy Secretary.

Order Confirming, Approving, and Placing the Central Valley Project Commercial Firm Power Service Rates into Effect on an Interim Basis

September 19, 1995.

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

By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to the Administrator of the Western Area Power Administration; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Federal Energy Regulatory Commission. Existing DOE procedures for public participation in power rate adjustments are located at 10 CFR Part 903.

Acronyms and Definitions

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

Composite rate:
: Energy rate that recovers capacity and energy revenue requirements.

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

Corps:
: United States Army Corps of Engineers.

CRD:
: Contract rate of delivery. The maximum amount of capacity that Western is contractually obligated to provide to a customer.

CVP:
: Central Valley Project.

DOE:
: Department of Energy.

DOE Order RA6120.2:
: An order dealing with power marketing administration financial reporting.

Energy base rate:
: Energy rate applied to energy sales below a 70 percent monthly load factor.

Energy component:
: The component of this rate which sets forth the charges for energy. It is expressed in mills/kWh and applied to each kWh made available to each customer.

Energy tier rate:
: Energy rate applied to energy sales at a 70 percent and higher monthly

load factor.
FERC:
Federal Energy Regulatory Commission.
FY:
Fiscal year.
Intertie:
Pacific Northwest-Pacific Southwest Intertie.
kW:
Kilowatt (1000 watts).
kW/month:
Kilowatt per month.
kWh:
Kilowatthour.
Load factor:
The ratio of total energy delivered compared to the maximum energy available during a specified period of time.
mills/kWh:
Mills per kilowatthour.
MW:
Megawatt (1000 kW).
NEPA:
National Energy Policy Act of 1969 (42 U.S.C. 4321 *et seq.*).
Northwest:
Northwest United States.
O&M:
Operation and maintenance.
PG&E:
Pacific Gas and Electric Company.
Power factor:
The ratio of real (kW) to apparent power (kVA) at any given point and time in an electrical circuit. Generally it is expressed as a percentage ratio.
PRS:
Power repayment study.
Provisional rates:
A rate which has been confirmed, approved, and placed in effect on an interim basis by the Deputy Secretary.
RAC:
Revenue adjustment clause.
Rate brochure:
A document prepared for public distribution explaining the rationale and background of the rate proposal contained in this rate order dated July 1995.
Reclamation:
U.S. Department of the Interior, Bureau of Reclamation.
Revenue requirement:
The revenues required to recover O&M expenses, purchase power and transmission service expenses, interest, deferred expenses, and Federal investments.
Secretary:
Secretary of Energy.
Western:
U.S. Department of Energy, Western Area Power Administration.

Effective Date

The new rates will become effective on an interim basis on the first day of the first full billing period beginning on or after October 1, 1995, and will be in effect pending FERC's approval of them or substitute rates on a final basis for a 2½-year period ending April 30, 1998, or until superseded.

Public Notice and Comment

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

1. The proposed rate adjustment was initiated on June 9, 1995, when a letter announcing an informal customer meeting was mailed to all commercial firm power customers and interested parties. The meeting was held on June 26, 1995, in Sacramento, California. At this informal meeting, Western explained the rationale for the rate decrease and rate design methodology, and answered questions.

2. A **Federal Register** notice was published on July 10, 1995 (60 FR 35556), officially announcing the commercial firm power rate adjustment, initiating the public consultation and comment period, announcing the public information and public comment forums, and presenting procedures for public participation.

3. On July 17, 1995, letters were mailed from Western's Sacramento Area Office to all commercial firm power customers and interested parties transmitting the **Federal Register** notice of July 10, 1995.

4. On July 19, 1995, a rate brochure was mailed to all customers and interested parties.

5. At the public information forum held on the morning of July 26, 1995, Western explained the rationale for the rate decrease and the rate design methodology in greater detail and answered questions.

6. The comment forum was held on the afternoon of July 26, 1995, to give the public an opportunity to comment for the record. Two customer representatives made oral comments.

7. Eight comment letters were received during the consultation and comment period. The consultation and comment period ended August 11, 1995. All formally submitted comments have been considered in the preparation of this rate order.

Project History

The CVP in the Central Valley Basin of California has twelve dams that create reservoirs with a total capacity of 10.66 million acre-feet of water. The CVP contains 615 miles of canals, five pumping plants, and eleven powerplants.

The Emergency Relief Appropriations Act of 1935 initially authorized the CVP to be constructed by Reclamation. In 1944, Congress authorized the American River Division to be constructed by the Corps. In 1949, the Division was reauthorized for integration into the CVP. The Trinity River Division was authorized by Congress in 1955. The San Luis Unit was authorized by Congress in 1960. In 1965, Congress authorized construction of the Auburn-Folsom South Unit as an addition to the CVP. Congress authorized the San Felipe Division in 1967, and the Allen Camp Unit in 1976. In 1964, Congress authorized the Intertie, of which the CVP has the right to use 400 MW of transmission capacity to import power from the Pacific Northwest.

PG&E and Western operate under Contract 2948A, executed in 1967, which provides for the sale, interchange, and transmission of 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 facilities cannot meet obligations to the preference customers, Contract 2948A provides Western the right to purchase capacity and energy from PG&E to meet those requirements. Any energy in excess of Western's obligations to preference customers can be sold to PG&E through a banking provision in the contract. The energy made available under this banking arrangement allows Western to supplement CVP generation to meet preference customer load.

Power generated from the CVP 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.

Each preference customer's 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.

Western's preference customer load level is limited under Contract 2948A to a maximum simultaneous demand, excluding project loads, of 1,152 MW. The maximum simultaneous demand is the sum of each preference customer's demand for CVP power at a coincidental moment, adjusted to the load center at the Tracy Switchyard. Notwithstanding the simultaneous demand limit, Western has contractual obligations to serve approximately 1,478 MW of firm CRD to its 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.

Power Repayment Study

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

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

Existing and Provisional Rates

A comparison of the existing and provisional rates follows:

COMPARISON OF EXISTING AND PROVISIONAL RATES

[Commercial Firm Power Rate Schedule]

Effective period	Existing	Provisional	Percent change
Composite Rate (mills/kWh)			
10/01/95 to 09/30/96	31.55	23.35	(26)
10/01/96 to 09/30/97	31.55	25.00	(21)
10/01/97 to 04/30/98	34.37	26.50	(23)
Capacity Rate ($/kW/month):			
10/01/95 to 09/30/96	6.57	4.03	(39)
10/01/96 to 09/30/97	6.57	4.32	(34)
10/01/97 to 04/30/98	7.16	4.58	(36)
Energy Base Rate (mills/kWh):			
10/01/95 to 09/30/96	17.73	14.83	(16)
10/01/96 to 09/30/97	17.73	15.93	(10)
10/01/97 to 04/30/98	19.33	16.93	(12)
Energy Tier Rate (mills/kWh):			
10/01/95 to 09/30/96	34.70	25.90	(25)
10/01/96 to 09/30/97	34.70	26.27	(24)
10/01/97 to 04/30/98	37.46	26.48	(29)

Certification of Rate

Western's Administrator has certified that the CVP commercial firm power rates placed into effect on an interim basis herein are the lowest possible rates consistent with sound business principles. The rates have been developed in accordance with administrative policies and applicable laws.

Discussion

The CVP provisional rates for commercial firm power change the CVP rate design and lower the rates currently in effect under Amended Rate Schedule CV–F7.

The CVP provisional composite rates reflect a 21 percent to 26 percent decrease from the current composite rates established in Amended Rate Schedule CV–F7. The recent decrease in customer CVP power purchases and the corresponding decrease in purchase power expenses are the major factors in the reduced rates.

The existing rate design collects 40 percent of the revenue requirement from capacity sales and 60 percent from energy sales. Effective October 1, 1995, the rate design will change to collect 35 percent of the revenue requirement from capacity sales and 65 percent from energy sales, to reflect the greater portion of Western's costs associated with energy. A reduction in capacity purchase costs also result from Western's Sacramento Area Office entering into an arrangement with PG&E that will reduce the cost of capacity supplied by PG&E, from the current rate of approximately $17.00/kW/month to $5.875/kW/month beginning in June 1996.

The capacity rate percentage decreases are larger than the energy base rate decreases for two reasons: (1) The change in rate design from a 40 percent capacity/60 percent energy split to a 35 percent capacity/65 percent energy split, and (2) the forecasted energy tier sales were reduced disproportionately to the overall reduced forecast of customer energy sales. Therefore, the energy tier revenues are smaller, leaving more revenue to be recovered through the energy base rate.

The energy tier rate is based on the average CVP Northwest energy rate in both the existing and the provisional rates. The energy tier rate decreases between 24 percent to 29 percent from the existing rates in Amended Rate Schedule CV–F7. The decrease is due to the reduction in current market prices for energy from the Northwest from the level projected in the PRS supporting the current CVP commercial firm power rates.

The provisional composite rates increase approximately 7 percent in FY 1997 and 6 percent in FY 1998 as a result of increases in purchase power rates from Northwest suppliers and a 3 percent escalation factor in Western's O&M expenses.

The existing and proposed revenue requirements for the Central Valley Project are as follows:

	Estimated 1996 revenue	
	Existing	Proposed
Revenue requirements:	$247,898,000	$193,618,000

The provisional rates provide sufficient revenues to satisfy the cost recovery criteria set forth in DOE Order RA6120.2.

Statement of Revenue and Related Expenses

The following table provides a summary of revenue and expense data through the 2½-year proposed rate approval period.

CENTRAL VALLEY PROJECT—COMPARISON OF COST EVALUATION RATE PERIOD REVENUES AND EXPENSES

[$1,000]

	Provisional ratesetting PRS 1996–98	Current rate PRS 1996–98	Difference
Revenue Distribution:			
O&M	105,521	113,066	(7,545)
Purchase Power	407,804	704,129	(296,325)
Transmission	45,098	46,191	(1,093)
Interest	29,933	26,902	3,031
Investment Repayment	21,598	25,077	(3,479)
Total Revenues	609,954	915,365	(305,411)

Basis for Rate Development

The CVP rate adjustment is needed to reflect reduced purchase power expenses that have occurred due to a decrease in customers' CVP power purchases. A major contributing factor in the rate decrease is reduced purchase power costs from PG&E. A rate decrease of 21 percent to 26 percent from the existing rate schedule occurs during the FY 1996 to FY 1998 period.

The provisional rates consist of a capacity rate, energy base rate, and energy tier rate. The energy tier rate will be applied in the same manner as it is in the current rate schedule, to any energy purchased at a 70 percent and higher monthly load factor. The energy tier rate is based on the average CVP Northwest energy rate.

The revenue recovery split between capacity and energy has changed from that in the existing rate schedule. Currently, the split is 40 percent capacity/60 percent energy. Under the provisional rates the split is 35 percent capacity/65 percent energy. This change reflects a greater portion of Western's costs associated with energy, and a decrease in capacity purchase costs.

The RAC, the Power Factor Adjustment Clause, the Low Voltage Loss Adjustment, and other provisions which are part of the commercial firm power rate schedule are not being modified at this time, and will remain as specified in the Amended Rate Schedule CV–F7.

Comments

During the public comment period, Western received eight written comments on the rate adjustment. In addition, two customer representatives commented during the July 26, 1995 public comment forum. All comments were reviewed and considered in the preparation of this rate order.

Written comments were received from the following sources:

Broadview Water District (California)
Calaveras Public Power Agency (California)
National Aeronautics and Space Administration—Ames Research Center (California)
Northern California Power Agency (California)
City of Palo Alto (California)
City of Santa Clara (California)
Trinity Public Utilities District (California)
Tuolumne Public Power Agency (California)

Representatives of the following organizations made oral comments:

City of Palo Alto (California)
Sacramento Municipal Utility District (California)

The comments received at the public meetings and in correspondence dealt with the commercial firm power rate design, specifically, the capacity/energy split for revenue recovery. All comments supported Western's efforts to reduce the rates and have the provisional rates in effect by October 1, 1995. Discussion of comments will address the capacity/energy split, and Western will address several comments with one response. The comments and responses, paraphrased for brevity, are discussed below. Direct quotes from comment letters are used for clarification where necessary.

Commercial Firm Power Rate Design (Capacity/Energy Split)

The following comments relate to the change in CVP rate design from recovering 40 percent of the revenue requirement from capacity sales and 60 percent from energy sales, to 35 percent from capacity and 65 percent from energy. Several comments supported the change in the capacity/energy split.

Comments: One customer commented that they opposed the change from a 40 percent capacity/60 percent energy split to a 30 percent capacity/70 percent energy split due to an inappropriate allocation of costs to energy, and for the reason that an unfair cost responsibility would be placed on the high load factor customers. However, this same customer sent a subsequent letter concurring with Western's proposal to change the 40 percent capacity/60 percent energy split to the 35 percent capacity/65 percent energy split used to develop the provisional rates. Other customers argued against keeping the 40 percent capacity/60 percent energy split for the reason that the 40 percent capacity/60 percent energy split is inequitable to the low load factor customers, and recommended that Western should change its capacity/energy ratio to be more in line with rate structures of other utility operations providing comparable services and serving the same area as Western. Other comments received recommended Western consider changing the capacity/energy split to at least a 30 percent capacity/70 percent energy split.

Response: Western initially proposed to continue the existing 40 percent capacity/60 percent energy revenue requirement split. Western then developed two studies analyzing the appropriate revenue requirement split for capacity and energy. In the first study the associated costs of each CVP resource were allocated to capacity or energy. This study indicated that approximately 45 percent of the total resource cost could be allocated to capacity and 55 percent allocated to energy. An initial study analyzing a fixed/variable cost approach indicated that approximately 30 percent of Western's costs could be fixed and allocated to capacity and approximately 70 percent could be variable and allocated to energy. Further refinement of this fixed/variable cost study resulted in 35 percent allocated to capacity and 65 percent to energy. Based on these studies, the future reduction in the capacity purchase rate from PG&E, current market conditions, and comments from the CVP preference customers, Western concluded that a 35 percent allocation to capacity and 65 percent allocation to energy was a reasonable split. By shifting a larger percentage of the costs from capacity to energy, Western believes that the provisional rates will more closely reflect the cost of providing capacity and energy to its customers. The rate design reflects Western's cost of capacity and energy to provide power to all CVP customers, not an individual customer's consumption of capacity or energy. The impact on individual customers will vary depending on that customer's usage of capacity or energy from the CVP. It is Western's position that Western has an obligation to meet all its contractual commitments and that the capacity/energy revenue split coupled with the energy tier rate recognizes Western's overall cost of power.

Environmental Evaluation

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

Executive Order 12866

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

Availability of Information

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

Submission to the Federal Energy Regulatory Commission

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

Order

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I confirm and approve on an interim basis, effective October 1, 1995, Rate Schedule CV–F8 for the Central Valley Project. The rate schedule shall remain in effect on an interim basis, pending confirmation and approval on a final basis by the Federal Energy Regulatory Commission, through April 30, 1998, or until superseded.

Issued in Washington, D.C., September 19, 1995.

Charles B. Curtis,

Deputy Secretary.

Schedule of Rates for Commercial Firm Power Service

Effective: October 1, 1995.

Available: Within the marketing area served by the Sacramento Area Office.

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

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

MONTHLY RATES

Period	Capacity	Energy
10/01/95–09/30/96.	$4.03/kW/month.	Base: 14.83 mills/kWh. Tier: 25.90 mills/kWh.
10/01/96–09/30/97.	4.32/kW/month.	Base: 15.93 mills/kWh. Tier: 26.27 mills/kWh.
10/01/97–04/30/98.	4.58/kW/month.	Base: 16.93 mills/kWh. Tier: 26.48 mills/kWh.

Billing

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

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

The energy base rate shall be applied to all energy sales below a 70 percent monthly load factor. The energy tier rate shall be applied to all energy sales at a 70 percent and higher monthly load factor. The monthly load factor shall be calculated based on the lesser of the customer's (1) maximum demand for the month or, if a scheduled customer, the maximum scheduled demand for the month; or (2) the CRD. Only power offered under this Rate Schedule CV–F8 will be used in the calculation of the load factor.

Adjustments

Billing for Unauthorized Overruns

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

For Revenue Adjustment

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 FY 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 FY that the RAC is being calculated (see Table 1).

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

5.6 RAC Calculation Period—The last recorded FY (October 1 through September 30).

5.7 Recorded Net Revenue—The annual net revenue available for repayment recorded in the PRS for the FY 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, 1999, to September 30, 1999.

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

Period	Projected Net Revenue ‘
October 1, 1995–September 30, 1996	$11,783,544
October 1, 1996–September 30, 1997	4,506,910
October 1, 1997–September 30, 1998	5,307,779

For Transformer Losses

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

For Power Factor:

The customer will be required to maintain a power factor at all points of measurement between 95-percent lagging and 95-percent leading. The low power factor charge (LPFC) will be calculated by multiplying the customer's maximum monthly demand by the kVar/kW rate for the customer's mean power factor as provided in the following Table 2:

TABLE 2.—KVAR/KW RATE TABLE

Power factor	Rate
0.94	$0.09
0.93	0.17
0.92	0.24
0.91	0.32
0.90	0.39
0.89	0.46
0.88	0.53
0.87	0.60
0.86	0.66
0.85	0.73
0.84	0.79
0.83	0.86
0.82	0.92
0.81	0.99
0.80	1.05
0.79	1.12
0.78	1.18
0.77	1.25
0.76	1.32
0.75 & below	1.38

A LPFC will be assessed when a customer's power factor is less than 95 percent.

(a) A charge of $2.50 per kVar will be assessed for every kVar required to raise a customer's power factor to 95 percent. The calculated power factor used to determine if a charge will be assessed is the arithmetic mean of a customer's measured monthly average power factor and their measured onpeak power factor, rounded to the nearest whole percent with 0.5 percent or greater rounded to the next higher percent.

(b) The mean power factor will be calculated at each customer's point of delivery. If a customer has multiple points of delivery, the power factor will be determined from totalized information from the points of delivery.

(c) No credit will be given for customers operating between 95 percent and 100 percent.

(d) Customers that have a monthly peak demand less than or equal to 50 kW will not be subject to the LPFC.

(e) The Contracting Officer may waive the LPFC for good cause in whole or in part.

[FR Doc. 95–25043 Filed 10–6–95; 8:45 am]
BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–5313–2]

Draft General NPDES Permit for Seafood Processors Within Three Nautical Miles of the Pribilof Islands, Alaska General NPDES Permit No. AK–G52–P000

AGENCY: Environmental Protection Agency, Region 10.