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Part II

Department of Energy

Western Area Power Administration

The Central Valley Project, the California-Oregon Transmission Project, the Pacific Alternating Current Intertie, and Information on the Path 15 Transmission Upgrade-Rate Order No. WAPA–115; Notice

DEPARTMENT OF ENERGY

Western Area Power Administration

The Central Valley Project, the California-Oregon Transmission Project, the Pacific Alternating Current Intertie, and Information on the Path 15 Transmission Upgrade-Rate Order No. WAPA–115

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of rate order.

SUMMARY: The Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–115, which includes Rate Schedules CV–F11, CPP–1, CV–T1, CV–NWT3, COTP–T1, PACI–T1, CV–TPT6, CV–SPR3, CV–SUR3, CV–RFS3, and CV–EID3, placing formula rates for power, transmission, and ancillary services for the Central Valley Project (CVP), transmission service on the California-Oregon Transmission Project (COTP), transmission service on the Pacific Alternating Current Intertie (PACI), and third-party transmission into effect on an interim basis. The Rate Order also provides information on the Western Area Power Administration's (Western) entitlement on the Path 15 Transmission Upgrade. The provisional formula rates will be in effect until the Federal Energy Regulatory Commission (Commission) confirms, approves, and places them into effect on a final basis or until they are replaced by other rates. The provisional formula rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of power investment and irrigation aid, within the allowable periods.

DATES: Rate Schedules CV–F11, CPP–1, CV–T1, CV–NWT3, COTP–T1, PACI–T1, CV–TPT6, CV–SPR3, CV–SUR3, CV–RFS3, and CV–EID3 will be placed into effect on January 1, 2005, and will be in effect until the Commission confirms, approves, and places the rate schedules in effect on a final basis through September 30, 2009, or until the rate schedules are superseded.

FOR FURTHER INFORMATION CONTACT: Mr. James D. Keselburg, Regional Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4418, or Ms. Debbie Dietz, Rates Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4453, e-mail *ddietz@wapa.gov.*

SUPPLEMENTARY INFORMATION: Under Amendment No. 4 to Delegation Order No. 0204–108, the Administrator of Western approved the existing Rate Schedule CV–F10 for CVP firm power, Rate Schedules CV–FT4, CV–NFT4, CV–TPT5, CV–NWT2, COTP–FT2, and COTP–NFT2 for transmission, and Rate Schedules CV–RFS3, CV–EID3, CV–SPR3, and CV–SUR3 for CVP ancillary services on April 14, 2001, (Rate Order No. WAPA–95, April 27, 2001). The Commission confirmed and approved the rate schedules on August 14, 2001, in FERC Docket No. EF01–5011–000. The existing rate schedules are effective from April 1, 2001, through December 31, 2004.

The provisional rates include a new transmission service for the PACI (Rate Schedule PACI–T1). The Rate Order also provides information on Western's entitlement on the Path 15 Transmission Upgrade. Western intends to turn over operational control of Western's entitlement on the Path 15 Transmission Upgrade to the California Independent System Operator (CAISO). As a result, the CAISO tariff and rates will apply to this service.

The existing firm power Rate Schedule CV–F10 is being superseded by Rate Schedule CV–F11. Under Rate Schedule CV–F10, the energy rate is 24.97 per mills/kilowatthour (mills/kWh) and the capacity rate is $3.80 per kilowattmonth (kWmonth). The composite rate is 30.83 mills/kWh. On December 31, 2004, the 1994 Power Marketing Plan expires. The 2004 Power Marketing Plan goes into effect January 1, 2005, and does not offer the same type of power service that is available under the 1994 Power Marketing Plan.

Under the 2004 Power Marketing Plan, each Preference Customer (except First Preference Customers) that has signed a Base Resource contract is a Base Resource Customer and is allocated a percentage of the Base Resource. Base Resource is primarily CVP and Washoe Project power output remaining after meeting project use, First Preference, and other operational requirements.

A First Preference Customer is defined in the 2004 Power Marketing Plan as a Preference Customer and/or a Preference entity (an entity qualified to use, but not using, Preference power) within a county of origin (Trinity, Calaveras, and Tuolumne) as specified under the Trinity River Division Act (69 Stat. 719) and the New Melones project provisions of the Flood Control Act of 1962 (76 Stat. 1173, 1191–1192).

The Base Resource and First Preference power provisional formula rates use percentages to recover the estimated power revenue requirement for January through September 2005 of $30 million, of which $1,110,000 will be recovered from the First Preference Customers and $28,890,000 will be recovered from the Base Resource Customers. These rates also include pass-through language for Host Control Area (HCA) and the Commission or other regulatory body credits or charges.

Under the 2004 Power Marketing Plan, a Customer's load can be met through First Preference, Base Resource, and/or Custom Product Power. Custom Product Power is power that is purchased to meet a Customer's load and may include long- and short-term purchases at various rates. All costs associated with Custom Product Power will be recovered through a formula rate in Rate Schedule CPP–1 that passes through the cost of the purchase to a specific Customer(s).

Rate Schedule CV–T1 supersedes Rate Schedules CV–FT4 and CV–NFT4, and CV–NWT3 supersedes Rate Schedule CV–NWT2. The existing and provisional formula rates for CVP transmission service include the costs for scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service. Provisional formula rates developed for CVP, COTP, and PACI transmission services are consistent with FERC Order No. 888.

The third-party transmission service rate schedule allows Western to pass through any costs it incurs for delivery of Western power over a third party's transmission system. The provisional formula rate for third-party transmission service in Rate Schedule CV–TPT6 is the same as the existing formula rate in CV–TPT5, with the exception of pass-through language for HCA and any Commission or other regulatory body charges or credits.

On January 1, 2005, under the provisional formula rate in Rate Schedule CV–T1, the CVP firm and non-firm transmission rates are the same. A change from the existing to the provisional formula rate is the pass-through of HCA charges or credits. A comparison of the estimated monthly and hourly rates from the provisional formula rate to the existing firm and non-firm rates is shown in the table below.

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATE CVP TRANSMISSION SERVICE

	Existing rates	Estimated rates from the provisional formula rate (effective 1/1/05)	Percent change
CVP Firm Transmission Rate ($/kWmonth)	$0.57	$1.03	81
CVP Non-Firm Transmission Rate (mills/kWh)	1.00	1.40	40

The provisional formula rate for CVP network integration transmission service (Rate Schedule CV–NWT3) is the same as the existing formula rate for this service with the exception of the pass through of any HCA charges or credits.

On January 1, 2005, under the provisional formula rate in Rate Schedule COTP–T1, the COTP firm and non-firm transmission rates are the same. A change from the existing formula rate to the provisional formula rate is the inclusion of pass-through language for HCA credits or charges. A comparison of the estimated monthly and hourly rates from the provisional formula rate to the existing firm and non-firm rates is provided in the table below.

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATES COTP TRANSMISSION SERVICE

	Existing rates	Estimated rates from the provisional formula rates (effective 1/1/05)	Percent change
COTP Firm Transmission Rate ($/kWmonth):			
Spring	$0.73	$1.87	156
Summer	$0.53	$1.87	253
Winter	$0.66	$1.88	185
COTP Non-Firm Transmission Rate (mills/kWh):			
Spring	1.00	2.55	155
Summer	0.72	2.54	253
Winter	0.91	2.59	185

PACI transmission service is a new service. Under the provisional formula rate in Rate Schedule PACI–T1, the firm and non-firm transmission rates are the same and include pass-through language for HCA and Commission or other regulatory body charges or credits. Under the provisional formula rate, the estimated monthly rates are $0.45/kWmonth for spring, summer, and winter. The estimated hourly PACI transmission rates are 0.61 mills/kWh for spring and summer and 0.62 mills/kWh for winter.

Western has not developed a separate rate for Western's entitlement on the Path 15 Transmission Upgrade, as Western intends to turn over operational control of Western's entitlement on the Path 15 Transmission Upgrade to the CAISO. The CAISO tariff and rates shall apply to Western's entitlement on the Path 15 Transmission Upgrade. Western has provided information on the treatment of revenue associated with its entitlement on the Path 15 Transmission Upgrade as part of this Rate Order.

Rate Schedules CV–RFS3, CV–EID3, CV–SPR3, and CV–SUR3 supersede Rate Schedules CV–RFS2, CV–EID2, CV–SPR2, and CV–SUR2, respectively. Provisional formula rates developed for the CVP ancillary services contain pass-through language for HCA and Commission or other regulatory body charges or credits. A comparison of existing rates to the estimated rates from the provisional formula rates is shown in the table below.

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATES CVP ANCILLARY SERVICES

Ancillary service type	Existing rates	Rate from the provisional formula rates	Change
Scheduling and System Control and Dispatch Service.	Included in the appropriate transmission rates	Included in the appropriate transmission rates	N/A.
Reactive Supply and Voltage Control Service.	Included in the appropriate transmission rates	Included in the appropriate transmission rates	N/A.
Spinning Reserve Service	$2.946 per kWmonth	Prices consistent with CAISO market	Varies.
Non-Spinning Reserve Service	$2.491 per kWmonth	Prices consistent with CAISO market	Varies.
Regulation and Frequency Response Service.	$2.496 per kWmonth	$2.57 per kWmonth	3%.

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATES CVP ANCILLARY SERVICES—Continued

Ancillary service type	Existing rates	Rate from the provisional formula rates	Change
Energy Imbalance Service	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 in like hours of energy or charged at the composite rate then in effect for CVP firm power.	Within Limits of Deviation Band: There is no financial charge for deviations (energy) within the bandwidth.	
	Outside Limits of Deviation Band: Positive Deviations (overdelivery)—the greater of no charge, or any additional cost incurred. Negative Deviations (underdelivery)—during on-peak hours the greater of three times the composite rate then in effect for CVP firm power or any additional cost incurred. During off-peak hours the greater of the composite rate then in effect for CVP firm power or any additional cost incurred.	Outside the Limits of the Deviation Band: Positive Deviations (overdelivery)—for any hourly average positive deviation, the amount of deviation outside the bandwidth is lost to the system. Negative Deviations (underdelivery)—for any hourly average negative deviation, the amount of deviation outside the bandwidth is charged at the greater of 150 percent of market price or actual cost.	

This Rate Order also includes a change in the Revenue Adjustment Clause (RAC) for the existing CVP Firm Power Rate (CV–F10) that would allow Western to make lump-sum payments to Customers for their share of the fiscal year (FY) 2004 RAC credit, if applicable. The change also delays calculation of the October through December 2004 RAC until all unmet obligations under existing contracts associated with business that occurred prior to January 1, 2005, are resolved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator, (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy, and (3) the authority to confirm, approve, and place into effect on a final basis to remand or to disapprove such rates to the Commission. Existing DOE procedures for public participation in power rate adjustments (10 CFR 903) were published on September 18, 1985.

Under Delegation Order Nos. 00–037.00 and 00–001.00A, 10 CFR 903, and 18 CFR 300, I hereby confirm, approve, and place Rate Order No. WAPA–115, the CVP power, CVP ancillary services, CVP, COTP, and PACI transmission service formula rates into effect on an interim basis. The new Rate Schedules CV–F11, CPP–1, CV–T1, CV–TPT6, CV–NWT3, COTP–T1, PACI–T1, CV–RFS3, CV–EID3, CV–SPR3, and CV–SUR3 will be promptly submitted to the Commission for confirmation and approval on a final basis.

Dated: November 18, 2004.

Kyle E. McSlarrow,

Deputy Secretary.

Order Confirming, Approving, and Placing the Central Valley Project Power Rates, the Central Valley Project, the California-Oregon Transmission Project, and the Pacific Alternating Current Intertie Transmission Rates and the Central Valley Project Ancillary Services Rates Into Effect on an Interim Basis, and Providing Information on the Path 15 Transmission Upgrade

This rate was established in accordance with section 302 of the DOE Organization Act, (42 U.S.C. 7152). This Act transferred to and vested in the Secretary of Energy the power marketing functions of the Secretary of the Department of the Interior and the Bureau of Reclamation (Reclamation) under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939, (43 U.S.C. 485h(c)), and other Acts that specifically apply to the project involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator, (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy, and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to the Commission. Existing DOE procedures for public participation in power rate adjustments (10 CFR 903) were published on September 18, 1985.

Acronyms and Definitions

As used in this Rate Order, the following acronyms and definitions apply:

1994 Power Marketing Plan: The 1994 CVP Power Marketing Plan (57 FR 45782 and 58 FR 34579).

2004 Power Marketing Plan: The 2004 CVP Power Marketing Plan (64 FR 34417) effective January 1, 2005.

Administrator: The Administrator of the Western Area Power Administration.

Ancillary Services: Those services necessary to support the transfer of electricity while maintaining reliable operation of the transmission provider's transmission system in accordance with standard utility practice.

Base Resource: The Central Valley and Washoe Project power output and existing power purchase contracts extending beyond 2004, as determined by Western to be available for marketing, after meeting the requirements of Project Use and First Preference Customers, and any adjustments for maintenance, reserves, transformation losses, and certain ancillary services.

CAISO: The California Independent System Operator is a Commission-regulated, State-chartered, nonprofit corporation, and the control area operator of most of California's transmission grid.

COI: The California-Oregon Intertie consists of three 500-kilovolt lines linking California and Oregon, the California-Oregon Transmission Project, and the Pacific Alternating Current Intertie. The Western

Electricity Coordinating Council establishes the seasonal transfer capability for the California-Oregon Intertie.

COI Rating Seasons: COI rating seasons are: summer, June through October; winter, November through March; and spring, April through May.

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

CPPA: The Calaveras Public Power Agency is a First Preference Customer located in Calaveras County, California.

CVP: The Central Valley Project is a multipurpose Federal water development project extending from the Cascade Range in northern California to the plains along the Kern River south of the city of Bakersfield, California.

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

Capacity Rate: The rate which sets forth the charges for capacity. It is expressed in dollars per kWmonth.

Commission: The Federal Energy Regulatory Commission.

Component 1: Part of a formula rate which is used to recover the costs for a specific service or product.

Component 2: Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Commission or other regulatory body that will be passed on to each appropriate Customer. The Commission or other regulatory body accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the applicable formula rate.

Component 3: Any charges or credits from the HCA applied to Western for providing this service that will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the applicable formula rate.

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

Contract 2947A: Contract No. 14–06–200–2947A, as amended, is Western's contract with the Pacific Gas and Electric (PG&E), the Southern California Edison, and the San Diego Gas and Electric (SDG&E) companies for extra high-voltage transmission and exchange service.

Contract 2948A: Contract No. 14–06–200–2948A is the Integration Contract between PG&E and Western. The contract provides for integrating Western's resources with PG&E's and requires PG&E to serve the combined PG&E/Western load with the integrated resource. The contract also requires PG&E to provide wheeling of the power to Western Customers on PG&E's system.

Custom Product Power: Power purchased by Western to meet a Customer's load.

Customer: An entity with a contract that receives service from the Western's Sierra Nevada Customer Service Region (SNR).

DOE: United States Department of Energy.

DOE Order RA 6120.2: A DOE order outlining power marketing administration financial reporting and ratemaking procedures.

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

ETCs: Existing Transmission Contracts. Long-term contracts for CVP transmission between Western and other parties, including contracts that predate the Open Access Transmission Tariff (OATT) and point-to-point transmission service under the OATT.

FERC: The Federal Energy Regulatory Commission (to be used when referencing Commission orders).

First Preference: A Customer or entity qualified to use Preference power within a county of origin (Trinity, Calaveras, and Tuolumne) as specified under the Trinity River Division Act of August 12, 1955 (69 Stat. 719) and the Flood Control Act of 1962 (76 Stat. 1173, 1191–1192).

FRN: **Federal Register** notice.

FY: Fiscal Year. October 1 through September 30.

HCA: Host Control Area. The control area in which SNR has a contractual arrangement to operate as a Sub-Control Area.

kV: Kilovolt. The electrical unit of measure of electric potential that equals 1,000 volts.

kW: Kilowatt. The electrical unit of capacity that equals 1,000 watts.

kWh: Kilowatthour. The electrical unit of energy that equals 1,000 watts in 1 hour.

kWmonth: Kilowattmonth. The electrical unit of the monthly amount of capacity.

Load: The amount of electric power or energy delivered or required at any specified point(s) on a transmission or distribution system.

Mill: A monetary denomination of the United States that equals one-tenth of a cent or one-thousandth of a dollar.

Mills/kWh: Mills per kilowatthour. The unit of charge for energy.

MW: Megawatt. The electrical unit of capacity that equals 1 million watts or 1,000 kilowatts.

NITS: Network Integrated Transmission Service.

O&M: Operation and maintenance.

OATT: Open Access Transmission Tariff.

PACI: Pacific Alternating Current Intertie. A 500-kV transmission project of which Western owns a portion of the facilities.

Path 15 Transmission Upgrade: A transmission project consisting of approximately 84 miles of new 500-kV transmission line in California's western San Joaquin Valley, starting at the existing Los Banos Substation near Los Banos in Merced County and extending generally south southeastward to the existing Gates Substation near Coalinga in Fresno County.

PG&E: The Pacific Gas and Electric Company.

Power: Capacity and energy.

Preference: The provisions of Reclamation Law which require Western to first make Federal power available to certain entities. For example, section 9(c) of the Reclamation Project Act of 1939 states that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936 (43 U.S.C. 485h(c)).

Provisional Rate: A rate which has been confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary.

PRS: Power repayment study.

RAC: Revenue Adjustment Clause. A provision in the existing CVP firm power rate schedule (CV–F10) that compares actual net revenue to projected net revenue from the ratesetting PRS on an FY basis.

Rate Brochure: A document dated May 2004 explaining the rationale and background for the rates contained in this Rate Order.

Reclamation: United States Department of the Interior, Bureau of Reclamation.

Reclamation Law: A series of Federal laws. Viewed as a whole, these laws create the originating framework under which Western markets power.

SCA: Sub-Control Area. Western's contract-based sub-control area within the Sacramento Municipal Utility District's control area.

SCC: The Sierra Conservation Center is a First Preference Customer located in Tuolumne County, California.

SNR: The Sierra Nevada Customer Service Region of Western.

TPPA: The Tuolumne Public Power Agency is a First Preference Customer located in Tuolumne County, California.

TPUD: The Trinity Public Utilities District is a First Preference Customer located in Trinity County, California.

Washoe Project: A Reclamation project located in the Lahontan Basin in west-central Nevada and east-central California.

Effective Date

The new interim rates will take effect on January 1, 2005, and will remain in effect until September 30, 2009, pending approval by the Commission on a final basis.

Public Notice and Comment

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

1. The proposed rate adjustment process began April 25, 2003, when Western mailed a notice announcing an informal meeting to all SNR Customers and interested parties.

2. Western held an informal meeting on May 14, 2003, in Folsom, California. At this informal meeting, Western explained the need for the rate adjustment, presented conceptual rate designs and methodologies, and answered questions. As a result of this meeting, Western received more than 180 comments and questions from interested parties. Western publicly posted these comments and questions with Western's responses on Western's Web site at *http://www.wapa.gov/sn/initiatives/post2004/rates/* in August 2003.

3. On May 7, 2004, Western mailed letters to all SNR Preference Customers and interested parties notifying them of the Proposed Rates **Federal Register** notice due to be published on or around May 13, 2004.

4. A **Federal Register** notice published on May 12, 2004 (69 FR 26370), announced the proposed rates for CVP, COTP, and PACI, began the public consultation and comment period, and announced the public information and public comment forums.

5. On May 12, 2004, Western mailed letters to all SNR Preference Customers and interested parties transmitting the **Federal Register** notice (69 FR 26370) and reiterating the dates and locations of the public information and comment forums.

6. On May 18, 2004, Western held a public information forum at the Folsom Community Center in Folsom, California. Western provided detailed explanations of the proposed rates for CVP, COTP, and PACI and a list of issues that could change the proposed rates. Western provided Rate brochures and informational (slide) handouts.

7. On June 3, 2004, Western mailed letters to all SNR Preference Customers and interested parties transmitting the Web site address to obtain copies of the slides used during the public information forum and providing instructions on how to receive a copy of the Rate Brochure.

8. As a result of the public information forum, several Customers requested meetings to ask clarifying questions of the proposed rates. Western met with the following Customers and/or their representatives on the dates indicated below. Notes from these meetings are included in the record.

Calaveras Public Power Agency, June 3, 2004
City of Shasta Lake, June 17, 2004
Northern California Power Agency (representing cities of Palo Alto, Roseville, Lodi, and Santa Clara (dba Silicon Valley Power), Port of Oakland, and Alameda Power and Telecom), June 3, 2004
Redding Electric, June 8, 2004 (via telephone) and June 16, 2004
Roseville Electric, June 1, 2004
Trinity Public Utility District, June 3, 2004
Tuolumne Public Power Agency, June 3, 2004
City of Santa Clara (dba Silicon Valley Power), July 30, 2004
Department of Energy (via telephone), August 10, 2004

9. In addition to the above meetings, Western communicated clarifying information on the proposed rates with the following Customers. This information is included in the record.

Calpine Corporation, California
City of Palo Alto, California
City of Shasta Lake, California
Duncan, Weinberg, Genzer and Pembroke, PC, Washington, DC
East Contra Costa Irrigation District, California
Energy Security Analysis, Inc., Massachusetts
Lassen Municipal Utility District, California
Northern California Power Agency, California
Redding Electric, California
Roseville Electric, California
Sierra Conservation Center, California
Turlock Irrigation District, California

10. On June 17, 2004, Western held a comment forum to give the public an opportunity to comment for the record. Eight individuals commented at this forum.

11. On July 28, 2004, Western published a letter updating the revenue requirements for Component 1 of the proposed formula rates for regulation and frequency response and spinning and non-spinning reserve services. This letter was sent to all interested parties by mail and electronic mail. The letter was also posted on Western's Web site at *http://www.wapa.gov/sn/initiatives/Post2004/rates/*.

12. Western received 27 comment letters during the consultation and comment period, which ended on August 10, 2004. All comments received prior to the close of the consultation and comment period have been considered in preparing this Rate Order. All written comments received are posted on Western's Web site at *http://www.wapa.gov/sn/initiatives/Post2004/rates/*.

Comments

Written comments were received from the following organizations:

Alameda Power and Telecom, California
Bella Vista Water District, California
Bay Area Municipal Transmission Group, California
Calaveras Public Power Agency, California
Calpine Corporation, California
City of Biggs, California
City of Gridley, California
City of Healdsburg, California
City of Lodi, California
City of Lompoc, California
City of Palo Alto, California

City of Santa Clara (dba Silicon Valley Power), California
City of Ukiah, California
Lassen Municipal Utility District, California
Modesto Irrigation District, California
Moffett Federal Airfield, California
NASA-Ames Research Center, California
Northern California Power Agency (representing the Turlock Irrigation District, the Bay Area Rapid Transit District, Placer County Water Agency, Truckee-Donner Public Utility District, the Lassen Public Utility District, the Plumas-Sierra Rural Electric Cooperative, the Port of Oakland, and the cities of Alameda, Biggs, Gridley, Lodi, Redding, Lompoc, Healdsburg, Ukiah, Palo Alto, and Roseville), California
Pittsburg Power Company, California
Plumas-Sierra Rural Electric Cooperative, California
Port of Oakland, California and Water Resources Pooling Authority (representing the Arvin-Edison Water Storage District, Banta-Carbona Irrigation District, Byron-Bethany Irrigation District, Cawelo Water District, Glenn-Colusa Irrigation District, James Irrigation District, Lower Tule River Irrigation District, Princeton-Codora-Glenn Irrigation District, Provident Irrigation District, Reclamation District 108, Santa Clara Valley Water District, Sonoma County Water Agency, West Stanislaus Irrigation District, Westlands Water District, and the West Side Irrigation District), California
Redding Electric, California
Roseville Electric, California
Sacramento Municipal Utility District, California
Trinity Public Utility District, California
Tuolumne Public Power Agency, California

Representatives of the following organizations made oral comments:

Bay Area Municipal Transmission Group (consisting of the cities of Alameda Power and Telecom, Silicon Valley Power, and the City of Palo Alto), California
City of Palo Alto, California
City of Roseville, California
City of Santa Clara (dba Silicon Valley Power), California
Power and Water Resources Pooling Authority, California
Modesto Irrigation District, California
Redding Electric, California
Sacramento Municipal Utility District, California

Project Description

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

The CVP is within the Central Valley and Trinity River basins of California. It includes 18 dams and reservoirs with a total storage capacity of 13 million acre-feet. The system includes 615 miles of canals, 7 pumping facilities, 11 powerplants with a maximum operating capability of about 2,074 MW, about 852 circuit-miles of high voltage transmission lines, 15 substations, and 16 communication sites. Reclamation operates the water control and delivery system and all of the powerplants except the San Luis Unit, which the State of California operates for Reclamation.

The Rivers and Harbors Act of 1937 authorized Reclamation to build the CVP, including Shasta and Keswick dams on the Sacramento River. The initial authorization included powerplants at Shasta and Keswick dams along with high-voltage transmission lines to transmit power from Shasta and Keswick powerplants to the Tracy Pumping Plant and to integrate Federal hydropower into other electric systems.

Additional CVP facilities were authorized by Congress through a series of laws. The American River Division was authorized in 1944 and includes the Folsom Dam and Powerplant and the Nimbus Dam and Powerplant on the American River. The Trinity Dam and Powerplant, Judge Francis Carr Powerplant, and Whiskeytown Dam and Spring Creek Powerplant were authorized as part of the Trinity River Division in 1955 and allocated up to 25 percent of the resulting energy to Trinity County for use within Trinity County. The San Luis Unit authorized in 1960, includes the B. F. Sisk San Luis Dam, San Luis Reservoir and William R. Gianelli Pump-Generating Plant, O'Neill Pump-Generating Plant, and Dos Amigos Pumping Plant. The Rivers and Harbors Act of 1962 authorized the New Melones Project and allocated up to 25 percent of the resulting energy to Calaveras and Tuolumne counties for use within the counties.

Western's SNR markets the surplus hydropower generation of the CVP and Washoe Project. Since 1967, under the terms of Contract 2948A with PG&E, CVP resources, along with other Western resources, have been integrated with PG&E resources. PG&E serves the combined PG&E/Western loads with the integrated resources.

PG&E has informed Western that it plans to terminate Contract 2948A on December 31, 2004. In anticipation of this eventuality, Western has worked with its Customers to develop and implement the 2004 Power Marketing Plan. The 2004 Power Marketing Plan was published in the **Federal Register**, (64 FR 34417) on June 25, 1999. It established the criteria for marketing CVP and Washoe Project power output for a 20-year period beginning on January 1, 2005, and ending on December 31, 2024.

The Base Resource is a fundamental component and the primary power product marketed through the 2004 Power Marketing Plan. Under previous marketing plans, Preference Customers received a fixed capacity and load factored energy allocation. Under the 2004 Power Marketing Plan, Preference Customers (other than First Preference) receive an allocated percentage of the Base Resource. The Base Resource is defined as the CVP and Washoe Project power output and any existing power purchase contracts extending beyond 2004, determined by Western to be available for marketing after meeting the requirements of project use and First Preference Customers, and any adjustments for maintenance, reserves, transformation losses, and certain ancillary services. In 2000, each CVP Customer (other than First Preference Customers) signed a contract with Western that specifies how Base Resource power will be made available under the 2004 Power Marketing Plan.

In marketing Federal hydroelectric power generated from the CVP, Western currently has 77 Preference and 38 project use Customers serving the equivalent of the annual electrical needs of 790,000 California households.

Power generated from the CVP is first dedicated to project use. The remaining power is allocated to various Preference Customers in California. Types of Preference Customers include: (1) Irrigation and water districts, (2) public utility districts, (3) municipalities, (4) Federal agencies, (5) State agencies, (6) rural electric cooperatives, and (7) Native American tribes.

According to the 2004 Power Marketing Plan, Western will market the Base Resource alone or in combination with custom products. One type of custom product is Custom Product Power, which is power supplied by Western to meet a Customer's load.

In 1964, Congress authorized construction of the 500-kV Pacific

Northwest-Pacific Southwest Alternating Current Intertie. On July 31, 1967, Reclamation (Western's predecessor), PG&E, the Southern California Edison Company, and SDG&E entered into Contract 2947A, an extra high-voltage transmission service and exchange agreement for the northern portion of the PACI. Under Contract 2947A, Western has a 400-MW entitlement of transmission capacity on the PACI. Contract 2947A terminates on December 31, 2004. A replacement agreement for Contract 2947A is being developed in a Commission process.

The COTP is a jointly owned 342-mile, 500-kV transmission line that connects the Captain Jack Substation in southern Oregon to Tracy/Tesla Substation in central California. Operational since March 1993, COTP provides a third high-voltage intertie between the Pacific Northwest and California. COTP owners other than Western are non-Federal participants.

Power Repayment Study

Western prepares a PRS each FY to determine if revenues will be sufficient to repay, within the required time, all costs assigned to the commercial power function. Repayment criteria are based on law, applicable policies including DOE Order RA 6120.2, and authorizing legislation.

Existing and Provisional Power Rates and Revenue Requirement

The 2004 Power Marketing Plan does not offer the same type of power service that was available under the 1994 Power Marketing Plan. Under the 1994 Power Marketing Plan, each Customer was allocated a contract rate of delivery (an amount of capacity) with associated energy, and the Customer was allowed to use up to that amount of capacity in any hour. The total monthly energy was determined based on the Customer's load factor. Under the 2004 Power Marketing Plan, Base Resource and First Preference power is primarily CVP hydrogeneration available subject to water conditions and operating constraints.

Under the 2004 Power Marketing Plan, the power revenue requirement for First Preference and Base Resource power includes O&M, purchased power for project use and First Preference Customer loads, interest expense, annual expenses (including any other statutorily required costs or charges), investment repayment for the CVP, and the Washoe Project annual power revenue requirement that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are applied to the total power revenue requirement, and the remainder is collected from Base Resource and First Preference Customers.

The Base Resource and First Preference power provisional formula rates recover a power revenue requirement through percentages for First Preference and Base Resource Customers. Base Resource Customer percentages were established through the public process for the 2004 Power Marketing Plan. The First Preference Customers' percentages to be used for billing purposes were developed as part of this rate process.

Under the 2004 Power Marketing Plan, a Customer's load can be met through First Preference, Base Resource, and/or Custom Product Power. Custom Product Power may include long- and short-term purchases at various rates. The existing rates do not have a parallel service. All costs associated with Custom Product Power will be recovered through a formula rate that passes through the cost of the purchase to a specific Customer(s). Such costs could include Western's scheduling costs and Components 2 and 3, as well as the cost of the power. A further discussion of the power revenue requirement and Custom Product Power is provided in the power revenue requirement discussion section later in this document.

COMPARISON OF EXISTING RATES AND PROVISIONAL FORMULA RATES FOR WESTERN POWER

Power service	Existing rate	Provisional formula rate	Percent change
Contract Rate of Delivery	30.83 mills/kWh	N/A	N/A.
Base Resource and First Preference	N/A	Percent of Annual Power Revenue Requirement.	N/A.
Custom Product Power	N/A	Pass Through	N/A.

Cost-of-Service Study

Western prepared a detailed cost-of-service study to determine the revenue requirement that will be recovered through the CVP regulation and frequency response service formula rate and the CVP, COTP, and PACI transmission service formula rates. This combined cost-of-service study integrates all three transmission systems. Each CVP, COTP, and PACI facility was researched in order to determine its functional use. The costs for CVP, COTP, and PACI facilities that support the transfer capability of the transmission system (excluding generation ties and radial lines) are included in the respective transmission system's revenue requirement; whereas, the cost for facilities that support the generation capability of the CVP system (including generation ties and radial lines) are included in the CVP generation revenue requirement and are used in the regulation and frequency response service revenue requirement. The costs associated with the CVP are allocated to the transmission and generation functions, based on a ratio of transmission or generation plant to total plant.

Western is using this study because it is more consistent with the methodology used in other Western regions. The costs allocated through the cost-of-service study include O&M, interest, and depreciation expenses. The cost-of-service study contains forecasted O&M and historical financial information, which is also in the PRS. Western's costs for scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service associated with the CVP, COTP, and PACI transmission service are included in and recovered through the respective transmission system's revenue requirement.

CVP Transmission

The provisional formula rate for CVP firm and non-firm transmission service results in an estimated monthly rate of $1.03 per kWmonth for January through September 2005. The provisional formula rate for CVP transmission includes three components:

Component 1:

$$\frac{\text{CVP TRR}}{\text{TTc} + \text{NITSc}}$$

Where:

TRR = Transmission revenue requirement.

TTc = Total transmission capacity under ETCs.

NITSc = Average of 12-month coincident peaks of NITS Customers at the time of the monthly CVP transmission system peak. For rate design purposes, Western's use of the transmission system to meet its statutory obligations is treated as NITS.

This formula rate also contains Components 2 and 3.

The cost-of-service study determines the revenue requirement for Component 1 of this service. The rates from Component 1 of the provisional formula rate may be discounted for short-term sales. The estimated rates from the provisional formula rate are subject to change prior to the rate taking effect.

CVP NITS

The estimated monthly revenue requirement for NITS effective January 1, 2005, is $1,021,712. The provisional formula rate for CVP NITS includes three components:

Component 1:

NITS Customer's monthly costs = NITS Customer's load ratio share times one-twelfth of the annual network TRR.

Where:

NITS Customer's load ratio share = The NITS Customer's hourly load (including behind the meter generation minus the NITS Customer's hourly Base Resource) coincident with the monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved transmission capacity) transmission service, expressed as a ratio.

Annual network TRR = Total CVP transmission revenue requirement less ETC revenues.

This formula rate also contains Components 2 and 3.

The cost-of-service study determines the revenue requirement for Component 1 of this service. The provisional formula rate for CVP NITS is based on the same revenue requirement that is used in the CVP firm and non-firm transmission formula rate. The NITS estimated monthly revenue requirement is subject to change prior to the rates taking effect.

COTP Transmission

The provisional formula rate results in estimated monthly rates for COTP firm and non-firm point-to-point transmission service of $1.87 per kWmonth for spring and summer and $1.88 per kWmonth for winter. The provisional formula rate for COTP firm and non-firm point-to-point transmission service consists of three components.

Component 1:

$$\frac{\text{COTP Seasonal Transmission Revenue Requirement}}{\text{Western's Share of COTP Seasonal Capacity}}$$

Component 1 is the ratio of the COTP seasonal transmission revenue requirement to Western's share of the COTP seasonal capacity (subject to curtailment). Western will update the rate resulting from Component 1 at least 15 days before the start of each COI rating season.

This formula rate also contains Components 2 and 3.

The cost-of-service study determines the revenue requirement for Component 1 of this service. The COTP cost-of-service study identifies the costs associated with the facilities that support the transfer capability of the COTP transmission system only. The amount of COTP capacity used in Component 1 of the formula rate will change with the seasonal transfer capability of the COI. The rates from Component 1 of the provisional formula rate may be discounted for short-term sales. The estimated rates from the provisional formula rate are subject to change prior to the rate taking effect.

PACI Transmission

PACI firm and non-firm transmission services are new services. The estimated rates from the formula rate for PACI firm and non-firm point-to-point transmission are $0.45 per kWmonth for spring, summer, and winter. The provisional formula rate for PACI firm and non-firm point-to-point transmission service consists of three components.

Component 1:

$$\frac{\text{PACI Seasonal Transmission Revenue Requirement}}{\text{Western's PACI Seasonal Capacity}}$$

Component 1 is the ratio of the PACI seasonal transmission revenue requirement to Western's share of the PACI seasonal capacity (subject to curtailment). Western will update the rate resulting from Component 1 at least 15 days before the start of each COI rating season.

This formula rate also contains Components 2 and 3.

The cost-of-service study determines the revenue requirement for Component 1 of this service. The PACI cost-of-service study identifies the costs associated with the facilities that support the transfer capability of the PACI transmission system. There are no existing rates for PACI transmission since it is currently covered under an existing contract. The amount of PACI capacity used in Component 1 of the formula rate will change with the seasonal transfer capability of the COI. The rates resulting from Component 1 of the provisional formula rate may be discounted for short-term sales. The estimated rates from the provisional formula rate are subject to change prior to the rate taking effect.

Third-Party Transmission

The provisional formula rate for third-party transmission includes three components. The first component is equivalent to the existing formula rate and allows for Western to pass through costs it incurs for using a third party's transmission system. The provisional formula rate also contains Components 2 and 3.

Path 15 Transmission Upgrade

Western is constructing the Path 15 Transmission Upgrade in conjunction with PG&E and Trans-Elect, Inc. Western will turn over operational control of its rights in the Path 15 Transmission Upgrade to the CAISO. Recovery of the transmission revenue requirement will be through the CAISO tariff and rates.

Existing and Provisional Transmission Rates

A comparison of the existing rates and the estimated rates from the provisional formula rates for CVP, COTP, and PACI transmission service follows:

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATES CVP, COTP, AND PACI TRANSMISSION SERVICE

	Existing rates (Note 1)	Estimated rates from the provisional formula rates (effective 1/1/05)	Percent change
CVP Firm Transmission Rate ($/kWmonth)	$0.57	$1.03	81
CVP Non-Firm Transmission Rate (mills/kWh)	1.00	1.40	40
CVP NITS Monthly Revenue Requirement	N/A	$1,021,712	N/A
Third-Party Transmission Rate	Pass Through	Pass Through	N/A
COTP Firm Transmission Rate ($/kWmonth):			
Spring	$0.73	$1.87	156
Summer	$0.53	$1.87	253
Winter	$0.66	$1.88	185
COTP Non-Firm Transmission Rate (mills/kWh):			
Spring	1.00	2.55	155
Summer	0.72	2.54	253
Winter	0.91	2.59	185
PACI Firm Transmission Rate ($/kWmonth):			
Spring	N/A	$0.45	N/A
Summer	N/A	$0.45	N/A
Winter	N/A	$0.45	N/A
PACI Non-Firm Transmission Rate (mills/kWh):			
Spring	N/A	0.61	N/A
Summer	N/A	0.61	N/A
Winter	N/A	0.62	N/A
Path 15 Transmission Upgrade	N/A	Per CAISO Tariff	N/A

Note 1: NITS service not provided prior to 1/1/05.

The estimated rates from the provisional formula rates are the same but are shown here as monthly and hourly rates for comparison to the existing firm and non-firm transmission rates. The increase in CVP transmission rates from the existing rate is primarily due to an increase in O&M costs and a change in Western's use of the CVP transmission system under the 2004 Power Marketing Plan. The increase in COTP transmission rates is primarily due to a decrease in Western's COTP capacity available for sale. The decrease in capacity occurs because of increased usage by DOE of a statutory entitlement at a rate which recovers only O&M costs.

Cost-of-Service Study—Ancillary Services

Six ancillary services will be offered by Western. The costs for two of these ancillary services: (1) Scheduling, system control and dispatch and (2) reactive supply and voltage control service from generation sources, are included in the CVP, COTP, and PACI transmission revenue requirements. The remaining four ancillary services are (3) spinning reserve service, (4) non-spinning reserve service, (5) regulation and frequency response service, and (6) energy imbalance service.

Western used the cost-of-service study to set a revenue requirement for Component 1 of the regulation and frequency response service. The provisional formula rate for this service is designed to recover only the costs associated with providing the service. The revenue requirement for regulation and frequency response service includes the CVP generation costs associated with providing the service and the non-facility costs allocated to the service, as well as the cost of energy, capacity, or foregone generation that support regulation and frequency response service. This formula rate also contains Components 2 and 3.

Spinning and non-spinning reserves will be sold at prices consistent with the CAISO market plus all costs incurred as a result of the sale, such as Western's scheduling costs and Components 2 and 3.

Existing Rates and the Provisional Ancillary Service Rates

A comparison of the existing rates and the estimated rates under the provisional formula rates for ancillary services follows:

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATES CVP ANCILLARY SERVICES

Ancillary service type	Existing rates	Estimated rate under the provisional formula rates	Change
Scheduling and System Control and Dispatch Service.	Included in the appropriate transmission rates	Included in the appropriate transmission rates	N/A
Reactive Supply Voltage Control Service.	Included in the appropriate transmission rates	Included in the appropriate transmission rates	N/A
Spinning Reserve Service	$2.946 per kWmonth	Prices consistent with CAISO market	Varies
Non-Spinning Reserve Service	$2.491 per kWmonth	Prices consistent with CAISO market	Varies
Regulation and Frequency Response Service.	$2.496 per kWmonth	$2.57 per kWmonth	3%

COMPARISON OF EXISTING AND ESTIMATED RATES FROM THE PROVISIONAL FORMULA RATES CVP ANCILLARY SERVICES—Continued

Ancillary service type	Existing rates	Estimated rate under the provisional formula rates	Change
Energy Imbalance Service	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 in like hours of energy or charged at the composite rate then in effect for CVP firm power.	Within Limits of Deviation Band: There is no financial charge for deviations (energy) within the bandwidth.	
	Outside Limits of Deviation Band: Positive Deviations (overdelivery)—the greater of no charge, or any additional cost incurred. Negative Deviations (underdelivery)—during on-peak hours the greater of three times the composite rate then in effect for CVP firm power or any additional cost incurred. During off-peak hours the greater of the composite rate then in effect for CVP firm power or any additional cost incurred.	Outside the Limits of the Deviation Band: Positive Deviations (overdelivery)—for any hourly average positive deviation, the amount of deviation outside the bandwidth (MWh) is lost to the system. Negative Deviations (underdelivery)—for any hourly average negative deviation, the amount of deviation outside the bandwidth (MWh) is charged at the greater of 150 percent of market price or actual cost.	

Certification of Rates

Western's Administrator certified that the provisional formula rates for First Preference, Base Resource, Custom Product Power, CVP, COTP, and PACI transmission and CVP ancillary services are the lowest possible rates consistent with sound business principles. The provisional formula rates were developed following administrative policies and applicable laws.

Power Revenue Requirement Discussion

According to Reclamation Law, Western must establish rates sufficient to recover O&M, purchased power expenses, other annual expenses, interest expenses, and repayment of power investment and irrigation aid.

The power revenue requirement for Base Resource and First Preference power includes the following expenses: annual investment repayment, purchases to firm the Base Resource and First Preference power deliveries for up to 2 hours, power purchased for project use and First Preference Customers, interest expense, O&M expense allocated to power, and the Washoe Project annual power revenue requirement that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are applied to the total power revenue requirement, and the remainder is collected from Base Resource and First Preference Customers. The power revenue requirement includes Components 2 and 3.

Statement of Revenue and Related Expenses

The following table provides a summary of projected revenue and expense data from the PRS through the 4¾-year provisional rate approval period. The table includes a comparison of existing rate data to provisional rate data and the difference.

PRS COMPARISON OF 4¾ YEAR RATE PERIOD (JAN 1, 2005–SEP 30, 2009), TOTAL REVENUES AND EXPENSES

	Existing rate (Note 1) ($000)	Provisional revenue requirement ($000)	Difference ($000)
Total Revenues	N/A	$812,165	N/A
Revenue Distribution Annual Expenses:			
O&M	N/A	343,555	N/A
Purchased Power	N/A	244,063	N/A
Interest	N/A	30,786	N/A
Other	N/A	139,315	N/A
Total Annual Expenses	N/A	757,719	N/A
Annual Principal Payments:			
Capitalized Expenses	N/A	0	N/A
Original Project and Additions	N/A	41,050	N/A
Replacements	N/A	13,396	N/A
Irrigation Aid	N/A	0	N/A
Total Principal Payments	N/A	54,446	N/A
Total Revenue Distribution	N/A	812,165	N/A

Note 1: The 2004 Power Marketing Plan does not offer the same type of power service that is available under the 1994 Power Marketing Plan; hence, the existing rates could not be used under the 2004 Power Marketing Plan.

Western will develop the power revenue requirement for First Preference and Base Resource power prior to the start of each FY. The power revenue requirement for the April through September period will be reviewed in March of each year (except March 2005). The review will analyze financial data from the October through February period, to the extent information is available, as well as forecasted data for the March through September period. If there is a change of $5 million or more, the power revenue requirement for the April through September period will be recalculated. A monthly power revenue requirement will be calculated by dividing each 6-month power revenue requirement by six. For the January through September 2005 period, a power revenue requirement will be calculated for a 9-month period instead of a year.

Provisional Formula Rate for First Preference Power

To have a consistent billing process for Base Resource and First Preference Customers, a percentage will be developed for each First Preference Customer before the start of each FY based on the following formula:

$$\text{First Preference Customer's \%} = \frac{\text{FP Customer Load}}{\text{Gen} + \text{Power Purchases} - \text{Project Use}}$$

Where:

FP Customer Load = A First Preference Customer's forecasted annual load (MWh).
Gen = The forecasted annual CVP and Washoe Project generation (MWh).
Power Purchases = Forecasted power purchase for project use and First Preference loads (MWh).
Project Use = The forecasted annual project use load (MWh).

For January through September 2005, the same formula will be used with data for the 9-month period instead of annual data.

During March of each year (except March 2005), each First Preference Customer's percentage will be reviewed by Western. The review will take into account the actual and estimated current FY data used in the First Preference Customer's percentage formula. If Western's review results in a change in a First Preference Customer's percentage of more than one-half of 1 percent, the percentage will be revised for that First Preference Customer for the remainder of the current FY. The review will not occur in March 2005 because the 2004 Power Marketing Plan will have been in effect for a very short period of time.

Each First Preference Customer's monthly charges are determined by the following formula:

First Preference Customer's monthly costs = 6-month power revenue requirement divided by six, times the First Preference Customer's percentage.

Starting with FY 2006, the First Preference Customers' share of the annual power revenue requirement is divided into two 6-month revenue requirements. The first 6-month revenue requirement will be collected from October through March and the second 6-month revenue requirement will be collected from April through September. The estimated April through September power revenue requirement will be reviewed by Western in March (with the exception of March 2005). Western's review will analyze financial data relating to the power revenue requirement for October through February, to the extent it is available, as well as forecasted data for March through September. If, as a result of Western's review, the power revenue requirement changes by $5 million or more, the April through September power revenue requirement will be revised.

The power revenue requirement for January through September 2005 will be divided by nine to determine a monthly power revenue requirement. Each First Preference Customer's percentage will be applied to the monthly power revenue requirement to determine each First Preference Customer's monthly costs. The estimated power revenue requirement for January through September 2005 is $30 million. The estimated First Preference Customers' revenue requirement for January through September 2005 is $1,110,000 (sum of all First Preference Customers' estimated percentages of 3.7 percent multiplied by the power revenue requirement for January through September 2005 of $30 million). The estimated power revenue requirement and First Preference Customers' percentages are subject to change prior to the rates taking effect.

Provisional Formula Rate for Base Resource

Base Resource Customer's monthly cost = Base Resource Customer's percentage times the Base Resource monthly revenue requirement.

A Customer's Base Resource percentage may be adjusted as provided for in the contract; *e.g.,* participation in the exchange program. After the First Preference Customers' share of the annual power revenue requirement has been determined, the remainder of the annual power revenue requirement is recovered from the Base Resource Customers. The Base Resource revenue requirement will be collected in two 6-month periods. For October through March, 25 percent of the Base Resource revenue requirement will be collected. For April through September, 75 percent of the Base Resource revenue requirement will be collected. Allocating the Base Resource revenue requirement in this manner aligns the base resource revenue requirement with the Base Resource availability during the two 6-month periods. CVP generation is greater in the April through September period than the October through March period. The shifting of the Base Resource revenue requirement will help minimize monthly per unit cost variations for the Customers.

A Base Resource monthly revenue requirement is calculated by dividing the Base Resource estimated 6-month revenue requirement by six. A Customer's Base Resource costs are independent of the Base Resource received. Base Resource energy not used by any Preference Customer will be sold, if possible, and the revenues will reduce the Base Resource revenue requirement. The revenues from the sale of surplus Base Resource will be applied to the estimated annual Base Resource revenue requirement for the following FY.

The estimated power revenue requirement for January through September 2005 is $30 million and the estimated First Preference Customers' revenue requirement is $1,110,000; therefore, the estimated Base Resource revenue requirement is $28,890,000. The Base Resource revenue requirement will be allocated 25 percent to the 3-month period from January through March 2005 and 75 percent to the 6-month period, April through September 2005. For January through March 2005, the estimated Base Resource revenue requirement is $2,407,500 per month. For April through September 2005, the estimated Base Resource revenue requirement is $3,611,250 per month. The estimated Base Resource revenue requirement for January through September 2005 may change prior to the rate taking effect.

Provisional Formula Rate for Custom Product Power

All costs associated with Custom Product Power will be recovered using a formula rate that passes through all costs of the purchase to a specific Customer(s). Such costs could include Western's scheduling costs and Components 2 and 3, as well as the cost of the power. Under the 2004 Power Marketing Plan, Custom Product Power is power supplied by Western to meet a Customer's load. Western may make Custom Product Power purchases for a group of Customers or for an individual Customer. Costs for Custom Product Power purchases that are funded in advance by the Customer(s) will be passed through to that Customer(s) based on the power forecasted to the Customer(s). Unless otherwise agreed to by Western, Custom Product Power funded in advance that is surplus to the load requirements of the Customer(s) will be sold. If the Customer(s) fails to have an account available to receive the proceeds from the sale of surplus Custom Product Power, the proceeds are forfeited to Western and will be applied to the Custom Product Power purchase cost for the Customer(s).

If the Custom Product Power purchase is funded through appropriations, Federal reimbursable, or use of receipts authority, the cost of the Custom Product Power is passed through to the Customer(s) that have that power in their final schedules. Custom Product Power funded through appropriations, Federal reimbursable authority, or use of receipts authority that is surplus to the load of the Customer(s) will be sold. Proceeds from the sale of surplus Custom Product Power funded through use of receipts authority, Federal reimbursable authority, or appropriations will be applied to the Custom Product Power purchase cost for the Customer(s).

Change in RAC in Existing CVP Firm Power Rate Schedule CV–F10

Western is changing the RAC for FY 2004. Under the existing CVP Firm Power Rate Schedule CV–F10, a RAC credit for FY 2004 would be applied in equal amounts to the nine power bills issued by Western from January through September 2005. Western is changing the RAC to allow Western to make lump-sum payments to Customers for their share of the FY 2004 RAC credit, as opposed to issuing credits in equal amounts to the power bills issued from January through September 2005. This change in the RAC will allow Western more flexibility as it moves to the 2004 Power Marketing Plan. This change will not affect the calculation of the FY 2004 RAC or the determination of each Customer's share of the FY 2004 RAC.

For the October to December 2004 RAC, Western is changing the existing process of calculating the RAC and applying the resulting RAC credit or surcharge to the power bills issued from April through September 2005. Western will delay calculation of the October through December 2004 RAC so that any outstanding project use true-ups and any unmet obligations under existing contracts associated with business that occurred prior to January 1, 2005, can be included in the October through December 2004 RAC. Once this data is available, Western will calculate the October through December 2004 RAC using the existing methodology. This will likely delay the October through December 2004 RAC until sometime in FY 2006. The resulting RAC credit or surcharge will be allocated among the power Customers taking firm power during October through December 2004 under the existing methodology. Western will initiate distribution of the RAC credit or surcharge within 60 days of completing the RAC calculation. If the result was a RAC credit, at Western's discretion, Western will either credit the Customers' power bills to the extent possible, or Western will make a lump-sum payment to the Customers for their share of the RAC. If the result is a RAC surcharge, at Western's discretion, Western could collect the payment in equal installments over 9 months or as a lump sum.

Comments

The comments and responses regarding changes in RAC procedure for CV-F10 and First Preference, Base Resource, and Custom Product Power formula rates, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarification where necessary.

A. *Comment:* Some of the First Preference Customers expressed concern that during several consecutive drought years, they would be paying for all of Western's costs that would normally be covered by revenues from the Base Resource. These Customers suggested an alternative methodology that affected both the First Preference and Base Resource Customers. The suggestion charged the First Preference Customers based on a percentage of repayment obligation as opposed to the receipt of energy or Base Resource percentage. Western could base the percentage of repayment obligation on some sort of average; *e.g.,* long-term average, 5-year rolling average, or a single average water year.

Response: Western considered these comments, reviewed the alternatives presented by the Customers, and evaluated several other scenarios that might mitigate the financial impacts experienced by the First Preference Customers. Western's analysis determined that the financial impacts experienced by the First Preference Customers are similar to those experienced by the Base Resource Customers. According to this analysis, the First Preference Customers do not pay a larger per unit cost. As a means of mitigating the First Preference Customers' concerns, Western reviewed estimated First Preference percentages in different hydrological years. As a result of this review, Western has determined a maximum percentage for each First Preference Customer: SCC 1.39 percent, CPPA 3.49 percent, TPUD 9.21 percent, and TPPA 3.42 percent. The maximum percentages were determined based on a critically dry year where there are hydrologic conditions that result in low CVP generation and, consequently, low levels of Base Resource. These maximum percentages are not used in instances where individual First Preference Customer percentages increase due to load growth. If a maximum percentage is used for determining a First Preference Customer's costs for more than 1 year, then Western will evaluate that First Preference Customer's percentage resulting from the formula rate versus the maximum percentage and make adjustments as appropriate.

B. *Comment:* A First Preference Customer requested that Western consider converting its monthly fixed payment obligation to a per kWh rate with periodic adjustments. This conversion would better parallel its cash flow from its retail Customers.

Response: While Western understands the complexity of managing cash flow with a variable power product, as is provided through the 2004 Power Marketing Plan, Western intends to provide the Customer with sufficient information to calculate a per unit rate. Changing to a billing method using per unit cost versus a fixed payment obligation would not change the First Preference Customer's share of Western power costs. As stated earlier, Western will review the power revenue requirement every 6 months. The power revenue requirement will be changed in March only if it exceeds the $5 million threshold. As part of the record for the rate case, Western has provided estimated annual power revenue requirements for January through September 2005 and FY 2006 through 2009. Western has provided estimated percentages for all First Preference Customers for January through September 2005 and for FY 2006 so that the First Preference Customers could use that data in developing their future budgets.

C. *Comment:* Several Customers expressed concern regarding the disposition of proceeds from the sale of surplus Custom Product Power. The proposed formula rate for Custom Product Power indicated that the proceeds are forfeited to Western if a Customer fails to have an account available to receive the proceeds from such a sale. The Customers requested that Western change this language to allow for the proceeds to be applied to future Custom Product Power purchases on behalf of the Customer(s).

Response: If Western receives the proceeds from the sale of surplus Custom Product Power, they will be applied to the current Custom Product Power cost for the Customer(s). Under its trust authority, Western cannot use these proceeds to fund future Custom Product Power purchases.

D. *Comment:* A Customer indicated its support of Western's intention to better align the Base Resource monthly revenue requirement with CVP generation. The Customer thought this procedure would help reduce monthly per unit cost variations for Western's Customers.

Response: Western notes the comment.

E. *Comment:* A Customer "applaud[ed] Western's efforts to separately track any costs associated with supplemental or custom products to ensure no cost shifting occurs with the Base Resource."

Response: Western notes the comment.

Provisional Formula Rate for CVP Firm and Non-Firm Transmission

The provisional formula rate for CVP firm and non-firm transmission includes three components:

Component 1

$$\frac{\text{CVP transmission revenue requirement}}{\text{TTc} + \text{NITSc}}$$

Where:

TTc = Total transmission capacity under ETCs.

NITSc = Average of 12-month coincident peaks of NITS Customers at the time of the monthly CVP transmission system peak. For rate design purposes, Western's use of the transmission system to meet its statutory obligations is treated as NITS.

This provisional formula rate also contains Components 2 and 3.

The rate from Component 1 will be used for CVP firm and non-firm transmission service. Western will revise the rate resulting from Component 1 of the provisional formula rate based on either of the following two conditions: (a) Updated financial data available in March of each year, and (b) a change in the numerator or denominator that results in a rate change of at least $0.05 per kWmonth. The estimated monthly rate resulting from Component 1 of the provisional formula rate for January through September 2005 has increased from $0.93 per kWmonth to $1.03 per kWmonth. The increase is primarily due to a correction in the classification of Western's rights on a third party's transmission system for CVP generation. The $1.03 per kWmonth rate is an 81 percent increase from the existing rate of $0.57 per kWmonth.

The estimated hourly rate from Component 1 of the provisional formula rate for CVP transmission service for January through September 2005 has increased from 1.30 mills/kWh to 1.40 mills/kWh for the same reason stated above. The 1.40 mills/kWh is a 40 percent increase from the existing CVP non-firm transmission service rate of 1.00 mill/kWh. The percentage increase for the estimated hourly rates is smaller than the percentage increase for estimated monthly rates because the existing CVP non-firm transmission rate was rounded up to 1.00 mill/kWh. The increase in CVP transmission rates from the existing rate is primarily due to an increase in O&M costs and a change in Western's use of the CVP transmission system under the 2004 Power Marketing Plan. Under the 1994 Power Marketing Plan, Western was reserving transmission capacity based on the maximum output of directly connected CVP generating plants under normal operating conditions. Under the 2004 Power Marketing Plan, Western's use of the CVP transmission system to meet its statutory obligations is treated as NITS for rate design purposes. The rates from Component 1 of the provisional formula rate may be discounted for short-term sales. The estimated rates from the provisional formula rate are subject to change prior to the rate taking effect.

The provisional formula rate for CVP transmission service is based on a revenue requirement that recovers: (1) The CVP transmission system costs for facilities associated with providing transmission service, (2) the non-facility costs allocated to transmission service, (3) CVP generation costs for providing reactive supply and voltage control from generation sources, (4) Component 2, (5) Component 3, (6) any other statutorily required costs or charges, and (7) any other costs associated with transmission service, including uncollectible debt. Revenues from the sales of short-term transmission will offset the transmission revenue requirement.

Component 1 of the provisional formula rate includes Western's cost for transmission scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service associated with the transmission service. The provisional formula rate applies to ETCs.

Provisional Formula Rate for CVP NITS

The provisional formula rate for CVP NITS includes three components:

Component 1:

NITS Customer's monthly demand charge = NITS Customer's load ratio share times one-twelfth ($1/12$) of the annual network TRR.

Where:

NITS Customer's load ratio share = The NITS Customer's hourly load (including behind the meter generation minus the NITS Customer's hourly Base Resource) coincident with the monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved transmission capacity) transmission service, expressed as a ratio.

Annual network TRR = Total CVP transmission revenue requirement less ETC revenues.

The Annual Network TRR will be revised when the rate from Component 1 of the CVP transmission rate under Rate Schedule CV–T1 is revised. This provisional formula rate also contains Components 2 and 3.

The provisional formula rate for CVP NITS is based on a revenue requirement that recovers: (1) The CVP transmission system costs for facilities associated with providing transmission service, (2) the non-facility costs allocated to transmission service, (3) CVP generation costs for providing reactive supply and voltage control from generation sources, (4) Component 2, (5) Component 3, (6) any other statutorily required costs or charges, and (7) any other costs associated with transmission service, including uncollectible debt. For January through September 2005, the estimated NITS monthly revenue requirement is $1,021,712. The estimated monthly revenue requirement resulting from the provisional formula rate has increased to $1,021,712 from the estimated monthly revenue requirement in the proposed rates of $926,316. The increase is primarily due to a correction in the classification of Western's rights on a third party's transmission system for CVP generation. NITS was not provided prior to January 1, 2005, so there is no existing monthly revenue requirement for NITS.

The provisional formula rate includes Western's cost for transmission scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service associated with the CVP NITS. The NITS estimated monthly revenue requirement is subject to change prior to the rates taking effect.

Provisional Formula Rate for Third-Party Transmission

The provisional formula rate for third-party transmission includes three components:

Component 1: Western will directly pass through any costs it incurs for using a third party's transmission system to the requesting Customer. Rates under this schedule are to be automatically adjusted as third-party transmission costs are adjusted.

The formula rate for this service also contains Components 2 and 3.

Provisional Formula Rate for COTP Firm and Non-Firm Point-to-Point Transmission

The provisional formula rate for COTP firm and non-firm transmission includes three components:

Component 1:

$$\frac{\text{COTP Seasonal Transmission Revenue Requirement}}{\text{Western's Share of COTP Seasonal Capacity}}$$

Component 1 is the ratio of the COTP seasonal transmission revenue requirement to Western's share of the COTP seasonal capacity (subject to curtailment). Western will update the rate from Component 1 at least 15 days before the start of each COI rating season. The rate from Component 1 will be used for COTP firm and non-firm transmission service.

This formula rate for this service also contains Component 2 and 3.

A comparison of the estimated monthly rates from Component 1 of the provisional formula rate for COTP point-to-point transmission service to the COTP firm point-to-point transmission service existing rates are shown in the table below.

COMPARISON OF EXISTING RATES TO ESTIMATED RATES FROM COMPONENT 1 OF THE PROVISIONAL FORMULA RATE FOR COTP FIRM POINT-TO-POINT TRANSMISSION SERVICE

Season	Existing rate	Estimated rates from the provisional formula rate	Percent increase
Spring	$0.73/kWmonth	$1.87/kWmonth	156
Summer	$0.53/kWmonth	$1.87/kWmonth	253
Winter	$0.66/kWmonth	$1.88/kWmonth	185

A comparison of the estimated hourly rates from Component 1 of the provisional formula rate for COTP point-to-point transmission service to the COTP non-firm point-to-point transmission service existing rates are shown in the table below.

COMPARISON OF EXISTING RATES TO ESTIMATED RATES FROM COMPONENT 1 OF THE PROVISIONAL FORMULA RATE FOR COTP NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

Season	Existing rate	Estimated rate from the provisional formula rate	Percent increase
Spring	1.00 mill/kWh	2.55 mills/kWh	155
Summer	0.72 mill/kWh	2.54 mills/kWh	253
Winter	0.91 mill/kWh	2.59 mills/kWh	185

The minimal change in the estimated rates from Component 1 of the provisional formula rate is due to the variance in the number of hours in the COI rating season. The increase in the estimated rates from the provisional formula rate from the existing rates is primarily due to a decrease in Western's COTP capacity available for sale. The decrease in capacity occurs because of increased usage by the DOE of its statutory entitlement at a rate which recovers only O&M costs.

The provisional formula rate for COTP firm and non-firm point-to-point transmission service is based on a revenue requirement that recovers: (1) The COTP transmission system costs for facilities associated with providing transmission service, (2) the non-facility costs allocated to transmission service, (3) CVP generation costs for providing reactive supply and voltage control from generation sources service, (4) Component 2, (5) Component 3, (6) any other statutorily required costs or charges, and (7) any other costs associated with transmission service, including uncollectible debt.

The provisional formula rate includes Western's cost for transmission scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service associated with COTP transmission. The provisional formula rate applies to COTP point-to-point transmission service. The rates from Component 1 of the provisional formula rate may be discounted for short-term sales. The estimated rates from the provisional formula rate are subject to change prior to the rate taking effect.

Provisional Formula Rate for PACI Firm and Non-Firm Transmission

The provisional formula rate for PACI firm and non-firm transmission includes three components:

Component 1

$$\frac{\text{PACI Seasonal Transmission Revenue Requirement}}{\text{Western's PACI Seasonal Capacity}}$$

Component 1 is the ratio of the PACI seasonal transmission revenue requirement to Western's share of the PACI seasonal capacity. Western will update the rate from Component 1 at least 15 days before the start of each COI rating season. The rate from Component 1 will be used for COTP firm and non-firm transmission service.

This formula rate for this service also contains Components 2 and 3.

The estimated monthly and hourly rates resulting from Component 1 of the provisional formula rate for PACI transmission service are shown in the table below.

ESTIMATED RATES FROM COMPONENT 1 OF THE PROVISIONAL FORMULA RATE FOR PACI TRANSMISSION

Season	Estimated monthly rate	Estimated hourly rate
Spring	$0.45/kWmonth	0.61 mill/kWh.
Summer	$0.45/kWmonth	0.61 mill/kWh.
Winter	$0.45/kWmonth	0.62 mill/kWh.

The minimal change in the estimated seasonal rates from Component 1 of the provisional formula rate is due to the variance in the number of hours in the COI rating season. There are no existing rates for PACI transmission since it is currently covered under an existing contract. The provisional formula rate for PACI transmission service is based on a revenue requirement that recovers: (1) The PACI transmission system costs for facilities associated with providing transmission service, (2) the non-facility costs allocated to transmission service, (3) CVP generation costs for providing reactive supply and voltage control from generation sources service, (4) Component 2, (5) Component 3, (6) any other statutorily required costs or charges, and (7) any other costs associated with transmission service, including uncollectible debt.

The provisional formula rate includes Western's cost for transmission scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service associated with PACI transmission. The provisional formula rate applies to PACI point-to-point transmission service. The rates from Component 1 of the provisional formula rate may be discounted for short-term sales. The estimated rates from the provisional formula rate are subject to change prior to the rate taking effect.

Path 15 Transmission Upgrade

Western intends to turn over operational control of its rights on the Path 15 Transmission Upgrade to the CAISO under Amendment No. 48 of the CAISO Tariff. Transmission service for Western's rights on the Path 15 Transmission Upgrade must be obtained under the terms and conditions established by the CAISO. Under Amendment No. 48, the CAISO remits to Western wheeling, congestion, and Firm Transmission Rights auction revenues associated with Western's rights on the Path 15 Transmission Upgrade. While Western is turning over its rights on the Path 15 Transmission Upgrade under Amendment No. 48, Western desires to work with the CAISO to return revenues that are in excess of Western's costs associated with Western's use of the Path 15 Transmission Upgrade. As a result, if a significant overcollection occurs, Western will work with the CAISO on the treatment of the overcollection.

Comments

The comments and responses regarding Western's entitlement on the Path 15 Transmission Upgrade, the CVP, COTP, and PACI firm and non-firm transmission, and CVP NITS formula rates, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarification where necessary.

A. *Comment:* A large number of Customers indicated that Western should consider developing transmission rates that result in comparable delivery costs for all Federal Customers. It was suggested that Western consolidate both Federal transmission costs and third-party transmission costs for delivering Base Resource energy when developing the CVP transmission revenue requirement. This consolidation would then allow for a sharing of costs between the Customers directly connected to the CVP transmission system, Customers that are not directly connected to the CVP transmission system, and any other users of the CVP transmission system. Another alternative was provided in the event that consolidation is not possible. That is, to provide the Customers that are not connected to the CVP transmission system relief by removing the CVP transmission costs from their Base Resource revenue requirement. By sharing costs, the Customers felt that all Customers would be treated equally and the legislative intent of limited development of the Federal transmission system would be preserved. Conversely, Western received several contrary opinions from Customers directly connected to the CVP transmission system. These Customers objected to the inequity of such a rate design.

Response: The 2004 Power Marketing Plan states that each entity is ultimately responsible for obtaining its own delivery arrangements to load. Western believes payment of Base Resource delivery costs, including CVP and third-party transmission, by the Customer receiving the Base Resource is consistent with the 2004 Power Marketing Plan and the appropriate method to recover such costs.

B. *Comment:* In Western's original proposal provided in May 2003, certain CAISO and PG&E charges were originally included in the transmission service for the PACI. Western's proposed rates presented in May 2004 excluded these costs from the PACI revenue requirement. Since the Commission process to negotiate the PG&E charges and potential credits for Western's transmission facilities is expected to continue well after these rates are implemented, and the Customer has no desire to have the rates increase as a result of these Commission-sponsored negotiations, the Customer suggests including the potential credits in the revenue requirement.

Response: Western understands the Customer's concern regarding the potential credits for Western's transmission facilities that could decrease the costs for delivering Western power on the PG&E system. Western does not have a method to estimate the amount of potential credits and will not receive these credits unless they are approved by the Commission. If Western were to reduce the third-party pass-through costs to reflect these credits prior to the Commission's approval, Western would not be collecting the full cost being charged to Western by PG&E.

C. *Comment:* A comment asserted that the intent of the Federal legislation authorizing the PACI was that Western's Customers would pay costs that would not exceed the cost of Federal construction. To ensure that all Customers receive the benefit intended by the Federal legislation authorizing the PACI, certain Western power delivery costs should be included in the PACI annual revenue requirement. The Customer referred to Western's original May 2003 informal rates proposal containing this approach.

Response: When Western proposed including third-party transmission costs in the PACI revenue requirement, PG&E had taken the position that Western's end-use Customers would have to pay PG&E's retail tariff costs (excluding energy costs) for delivery of Western power. Under that scenario, Western contemplated including third-party transmission costs in the PACI revenue requirement. In March 2004, PG&E filed with the Commission a wholesale distribution tariff rate for delivery of Western power to Western's end-use Customers. Western will pursue credit for its facilities in the Commission proceedings on PG&E's filing.

D. *Comment:* Several Customers connected to the CVP transmission system asked that Western change the CVP transmission formula rate determinant from forecasted CVP generation to "maximum output from the CVP Base Resource generation." The comment indicated that the proper recovery methodology for the capital investment and ongoing O&M expenses associated with transmission facilities represents a capacity related investment that is based upon a firm-peak delivery capability of facilities.

Response: Western understands the Customers' concerns. Using the maximum operating capacity of the CVP northern power plants under normal operating conditions (annual peak) was appropriate under the 1994 Power Marketing Plan, due to contractual obligations under Contract 2948A. The 2004 Power Marketing Plan does not offer the same type of power service that is available under the 1994 Power Marketing Plan. Under the 2004 Power Marketing Plan, Base Resource and First Preference power is primarily the output of the CVP, which varies month to month. Under the 2004 Power Marketing Plan, Western has changed its use of the CVP transmission system for the delivery of CVP northern power plants generation from an annual peak to monthly peaks for rate design purposes. Western's treatment of its statutory obligations in the CVP transmission rate design is consistent with the 2004 Power Marketing Plan and NITS under Western's OATT.

E. *Comment:* A Customer informed Western of the significant financial impact the last increase in transmission rates had on its company and asked that Western charge all transmission Customers on the same basis to preserve equity and fairness. The Customer recommends that the proposed transmission rates be cost-based, allocated on cost causation principles, and recognize the transmission system investments made by Customers connected to the CVP transmission system. The Customer felt that Western's proposal to allocate transmission cost using a coincident peak billing determinant was discriminatory and unfairly shifted costs to contract transmission Customers.

Response: Western in its last rate case, as in this rate case, uses a Commission-approved methodology of plant-based cost allocation. As demonstrated in the Rate Brochure, NITS and ETC Customers pay the same per unit cost. As mentioned in Western's response to the comment above, Western is marketing a different product under the 2004 Power Marketing Plan than was offered under the 1994 Power Marketing Plan. This change requires Western to use a different type of transmission service for CVP generation and changes the billing determinant in the formula rate. Under the OATT, Customers can choose the type of transmission service that best fits its needs, NITS or point-to-point.

Provisional Rates for Ancillary Services

Western's costs for providing transmission scheduling, system control and dispatch service, and reactive supply and voltage control from generation sources service are included in the appropriate transmission revenue requirement.

Provisional Formula Rate for Spinning Reserve

The provisional formula rate for spinning reserve is the price consistent with the CAISO market plus all costs incurred as a result of the sale of spinning reserves, such as Western's scheduling costs and Components 2 and 3.

For Customers that have a contractual obligation to provide reserves to Western and do not fulfill that obligation, the penalty for nonperformance will be the greater of actual costs or 150 percent of the market price.

Revenues from spinning reserve sales will offset the power revenue requirement. The cost for spinning reserve required to firm CVP generation for the current hour and the following hour is included in the power revenue requirement.

Based on comments received, Western has modified its proposed rate to the provisional rate stated above. Western believes this addresses the comments regarding the spinning reserve proposed formula rate and provides a benefit to all power Customers of the ancillary services available from the CVP.

Provisional Formula Rate for Non-Spinning Reserve

The provisional formula rate for non-spinning reserve is the price consistent with the CAISO market plus all costs incurred as a result of the sale of non-spinning reserves, such as Western's scheduling costs and Components 2 and 3.

For Customers that have a contractual obligation to provide reserves to Western and do not fulfill that obligation, the penalty for nonperformance will be the greater of actual costs or 150 percent of the market price.

Revenues from non-spinning reserve sales will offset the power revenue requirement. The cost for non-spinning reserve required to firm CVP generation for the current hour and the following hour is included in the power revenue requirement. Based on comments received, Western has modified its proposed rate to the provisional rate stated above. Western believes this addresses the comments regarding the non-spinning reserve proposed formula rate and provides a benefit to all power Customers of the ancillary services available from the CVP.

Provisional Formula Rate for Regulation and Frequency Response Service

The provisional formula rate for regulation and frequency response service includes three components:

Component 1

$$\frac{\text{Annual Revenue Requirement}}{\text{Annual Regulating Capacity kW}}$$

The revenue requirement includes: (1) The CVP generation costs associated with providing regulation and frequency response service, (2) the non-facility costs allocated to regulation and frequency response service, (3) Component 2, (4) Component 3, (5) any other statutorily required costs or charges, and (6) actual purchase costs. Western will revise the rate from Component 1 of the provisional formula rate based on either of the following two conditions: (a) updated financial data available in March of each year, and (b) a change in the rate of at least $0.25 per kWmonth.

The annual regulating capacity is the total regulating capacity bandwidths provided by Western under the interconnected operations agreements with SCA members. The penalty for nonperformance by an SCA member who has committed to self-provide its regulating capacity requirement will be the greater of actual costs or 150 percent of the market price.

This formula rate also contains Components 2 and 3.

The regulation and frequency response service will be recovered from SCA members that have signed an interconnected operations agreement with Western. The revenues from regulation and frequency response service will be applied to the power revenue requirement. The estimated rate from the provisional formula rate is subject to change prior to the rate taking effect.

Provisional Formula Rate for Energy Imbalance Service

The provisional formula rate for energy imbalance service includes three components:

Component 1: If there is an hourly average negative deviation (underdelivery) outside the bandwidth, the amount of the deviation outside of the bandwidth will be charged at the greater of 150 percent of market price or actual cost. If there is an hourly average positive deviation outside the bandwidth, the amount of the deviation outside of the bandwidth is lost to the system.

This formula rate also contains Components 2 and 3.

Under the provisional formula rate, deviations outside the bandwidth are energy calculations done on an average hourly basis. There is no financial charge for deviations within the bandwidth. The energy imbalance rate will apply to SCA members that have signed an interconnected operations agreement with Western. The revenues from energy imbalance service will be applied to the power revenue requirement.

Comments

The comments and responses regarding the spinning reserve, non-spinning reserve, regulation and frequency response service, and energy imbalance service formula rates, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarification where necessary.

A. *Comment:* Several Customers indicated that the inclusion of purchases to support regulation and spinning and non-spinning reserve service was inappropriate given how Western expects to operate the SCA.

Response: Western considered these comments and removed the estimate for the purchases from the revenue requirements. If actual purchase costs are incurred to support these services, these costs will be recovered through the appropriate formula rate.

B. *Comment:* Several Customers expressed concern about the formula used to determine regulation capacity in the proposed rates. According to Western, this formula is used in practice by other wholesale utilities.

Response: Western considered this comment, and the formula for determining regulation capacity is no longer part of the regulation and frequency response service formula rate. Regulating capacity will be determined as provided for in the interconnected operations agreement with Western.

C. *Comment:* A large number of Customers commented that Western should consider providing a Base Resource share of ancillary service benefits regardless of control area restrictions. These Customers indicated that Western's proposal to sell surplus ancillary services at prices consistent with CAISO markets is discriminatory to Customers not connected to the CVP transmission system. Western's proposed formula rates allow for SCA members to receive ancillary services at cost. These Customers that are not connected to the CVP transmission system requested that Western remedy this discriminatory treatment of ancillary service sales to Customers not connected to the CVP transmission system by allowing proportionate access to these ancillary services to all of its Customers at similar rates prior to selling to the market.

Response: Western has revised the formula rate for spinning and non-spinning reserve services from the proposed formula rates. As a result, spinning and non-spinning reserves are sold at a price consistent with the CAISO market regardless of whether a Customer is connected to the CVP transmission system. Due to existing scheduling constraints, Western is not able to provide regulation and frequency response and energy imbalance to Western Customers outside of the SCA/HCA.

D. *Comment:* A Customer suggested that Western should consider a higher penalty for underdeliveries for energy imbalance service. The Customer recommended that Western charge 300 percent of actual cost as opposed to the greater of 150 percent of market price or actual cost, as indicated in the proposed formula rate for this service.

Response: Western understands the concern expressed by the Customer. Western believes that an increase to 300 percent may be more punitive than necessary. Western believes that actual cost or 150 percent of market price is sufficient incentive for Customers to remain inside the bandwidth.

E. *Comment:* A direct connected generation Customer noticed that the proposed formula rates did not have any crediting or offsetting mechanism for reactive supply and voltage control. The Customer requested that to the extent that Western compensates its own generation for providing the above services, then other Western Customers with generation that provide the same service must also be compensated.

Response: Western understands the Customer's concerns. The provisional rates do not provide for a credit for reactive supply and voltage control from generation sources to any party, including Western.

F. *Comment:* One Customer that is connected to the CVP transmission system requested that Western develop provisions that would allow CVP transmission Customers to self-provide regulation and operating reserves.

Response: Western had provisions in the proposed rates to allow crediting of self-provided ancillary services. Self-provision is included in the interconnected operations agreement and has been taken out of the provisional rates.

F. *Comment:* A Customer indicated that the current proposed rates are several times higher than rates presented in 2003 and provided a table (*see below*). The Customer indicated that Western had not provided any explanation why the rates rose so dramatically since May 2003 and whether or not this volatility was expected to continue.

ANCILLARY SERVICE PER UNIT COST COMPARISON

Service	May 2003 per unit cost	May 2004 per unit cost	Percent increase
Scheduling and System Control and Dispatch	$60.00/E-tag	By contract	N/A
Reactive Power and Voltage Control	$0.07/kWmonth	Assigned by transmission system.	N/A
Operating Reserve—Spinning	$0.31/kWmonth	$3.30/kWmonth	965
Operating Reserve—Supplemental Reserve Service (non-spin)	$0.19/kWmonth	$2.52/kWmonth	1226
Regulation and Frequency Response	$0.40/kWmonth	$6.33/kWmonth	1483

Response: Western's provisional rates for spinning and non-spinning reserve service are based on prices consistent with the CAISO markets. As such, the comparison above is no longer applicable. For regulation and frequency response service, as Western explained during the public information forum and accompanying slides, the increase in comparative rates for regulation and frequency response service was primarily due to increased O&M costs used in the cost-of-service study. In addition, Western used a Reclamation FY 2002 Ancillary Services Study to estimate hourly capacity amounts available from the CVP plants for regulation and frequency response service. These capacity amounts translated into purchase costs that were included in the estimated revenue requirements for the applicable services. In a letter to all interested parties on July 28, 2004, Western made a change to the revenue requirement for Component 1 of the formula rate for regulation and frequency response service. Western removed the purchase costs for regulation and frequency response service, and the appropriate revenue requirement was adjusted. This change in revenue requirement is documented in the table below. If purchase costs are incurred in providing of this service, these costs will be included in the next revision to the revenue requirement.

CHANGE IN REVENUE REQUIREMENT FOR REGULATION AND FREQUENCY RESPONSE SERVICE

Service	Revenue requirement with purchase costs	Revised revenue requirement without purchase costs
Regulation with Frequency Response Service	$2,277,692	$905,613

Since the publication of this letter, the revenue requirement was further revised to $972,405. The estimated revenue requirement increased slightly as a result of an increase in the regulating capacity needed for SCA members. Based on the revised revenue requirement, a revised cost-of-service study, and the provisional formula rate for regulation and frequency response service, the estimated rate is now $2.57 per kWmonth, which represents a 3 percent increase from Western's regulation and frequency response service existing rate.

General Comments

General comments and responses regarding operational considerations, power scheduling, and extension of the comment period, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarification where necessary.

Operational Considerations

A. *Comment:* A Customer was particularly concerned that an ''operational decision [regarding control area participation] should not be made without consideration of the rate and cost impacts on the Customers. One of the criteria used by Western to make its operational decision was cost effectiveness.'' The Customer did not feel that the proposed rates demonstrated that the SCA is cost effective and Customers should not be forced to pay costs higher than the CAISO.

Response: Rates for CVP power and power-related services are designed to recover the costs associated with providing the service. Customers have the option to self-provide spinning and non-spinning reserves and regulation and frequency response service, which gives them some flexibility to determine their own costs. The operational decision regarding Western's choice for joining a control area was set in a separate public process and is outside the scope of this public process.

B. *Comment:* A number of Customers expressed an interest in Western initiating a process to find additional ways to enhance the Western SCA: to ameliorate the uncertainty and ambiguities associated with the termination of Contracts 2947A, 2948A, and related contracts; to assess and promote the ability to dynamically schedule with the Western SCA load not directly connected to the CVP transmission system; to investigate ways to develop a ''grid best'' structure with regard to Western and all its Customers; and to explore mechanisms to assure needed future capital expenditures for transmission and power supply are provided in a timely manner. Another Customer asked that Western recognize that some Customers have existing agreements, like a metered subsystem, and should consider allowing these Customers to dynamically schedule their resources with the CAISO.

Response: These comments are outside the scope of this public process. The termination of Contracts 2947A, 2948A, and other related contracts is being addressed in the Commission technical conferences with the affected parties.

Power Scheduling

A. *Comment:* A number of Customers not directly connected to the CVP transmission system stated that they expected Western to minimize its costs by scheduling the CVP generation located in the CAISO's control area to Customers in the CAISO control area.

Response: Western seeks to minimize costs for all activities relating to delivering Western power to its Customers. To the extent practicable, CVP generation in the CAISO control area will be scheduled to project use, First Preference, and Base Resource Customers in the CAISO control area.

Extension of the Comment Period

A. *Comment:* Several Customers requested an extension of the comment period for this public process. These requests were made primarily because entities are interested in evaluating the ancillary service formula rates in association with the recently signed Sacramento Municipal Utility District (SMUD) and Western interconnection agreement and soon to be negotiated intra-SCA agreements between Western and SCA members.

Response: Western understands the concern expressed by these Customers. Western has committed to providing updated revenue requirement and/or rate information on or before December 1, 2004, for all rates except COTP and PACI transmission. The COTP and PACI transmission rate information will be provided on or before December 15, 2004, when the winter COI rating information should be available. Western cannot afford a delay in this rate process given that service must begin January 1, 2005.

Availability of Information

Information about this rate adjustment, including power repayment studies, comments, letters, memorandums, and other supporting material made and kept by Western and used to develop the provisional rates, is available for public review in the Sierra Nevada Regional Office, Western Area Power Administration, located at 114 Parkshore Drive, Folsom, California.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

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

Environmental Compliance

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

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Small Business Regulatory Enforcement Fairness Act

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

Submission to the Federal Energy Regulatory Commission

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

Order

In view of the foregoing and under the authority delegated to me, I confirm and approve on an interim basis, effective January 1, 2005, Rate Schedules CV–F11, CPP–1, CV–T1, CV–TPT6, CV–NWT3, COTP–T1, PACI–T1, CV–RFS3, CV–EID3, CV–SPR3, and CV–SUR3 for the Central Valley and the California-Oregon Transmission Projects, and the Pacific Alternating Current Intertie of the Western Area Power Administration. The rate schedules shall remain in effect on an interim basis, pending the Commission's confirmation and approval of them or substitute rates on a final basis through September 30, 2009.

Dated: November 18, 2004.

Kyle E. McSlarrow,

Deputy Secretary.

Rate Schedule CV–F11 (Supersedes Schedule CV–F10)

Central Valley Project; Schedule of Rates for Base Resource and First Preference Power

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To the Base Resource (BR) and First Preference (FP) power Customers.

Character and Conditions of Service: Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract. This service includes the Central Valley Project (CVP) transmission, spinning, and non-spinning reserve services.

Power Revenue Requirement: Western will develop the Power Revenue Requirement (PRR) prior to the start of each fiscal year (FY). The PRR will be divided into two 6-month periods, October through March and April through September. A monthly PRR will be calculated by dividing each 6-month PRR by six. The PRR for the April through September period will be reviewed in March of each year (except March 2005). The review will analyze financial data from the October through February period, to the extent information is available, as well as forecasted data for the March through September period. If there is a change of $5 million or more, the PRR for the April through September period will be recalculated. For the January through September 2005 period, a monthly PRR will be calculated by dividing the PRR for that period by nine.

First Preference Power Formula Rate:

Component 1:

$$\text{FP Customer Percentage} = \frac{\text{FP Customer Load}}{\text{Gen} + \text{Power Purchases} - \text{Project Use}}$$

FP Customer Charge = FP Customer Percentage × MRR

Where:

FP Customer Load = An FP Customer's forecasted annual load in megawatthours (MWh).

Gen = The forecasted annual CVP and Washoe generation (MWh).

Power Purchases = Power purchases for project use and FP loads (MWh).

Project Use = The forecasted annual project use loads (MWh).

MRR = Monthly Power Revenue Requirement.

Western will develop the FP Customer percentage prior to the start of each FY. During March of each FY (except March 2005), each FP Customer's percentage will be reviewed. If, as a result of the review, there is a change in the FP Customer's percentage of more than one-half of 1 percent, the percentage will be revised for the April through September period.

The percentages in the table below are the maximum percentages for each FP Customer that will be applied to the MRR. The maximum percentages were determined based on a critically dry year where there are hydrologic conditions that result in low CVP generation and, consequently, low levels of BR. These maximum percentages are not used in instances where individual FP Customer percentages increase due to load growth. If these maximum percentages are used for determining the FP Customer's charges for more than 1 year, then Western will evaluate their percentage from the formula rate versus the maximum percentage and make adjustments as appropriate.

FP CUSTOMERS' MAXIMUM PERCENTAGES

FP customers	Maximum FP customer's percentage applied to the MRR
Sierra Conservation Center	1.39
Calaveras Public Power Agency	3.49
Trinity Public Utility District	9.21
Tuolumne Public Power Agency	3.42
Total	17.51

Below is a sample calculation for an FP Customer monthly charge for power.

FP CUSTOMER MONTHLY CHARGE SAMPLE CALCULATION

Example: First preference customer charge calculation	
FP Customer Load—MWh	10,000
Washoe generation—MWh	2,500
CVP generation—MWh	3,700,000
Project Use Load—MWh	1,200,000
Project Use purchase—MWh	47,000
FP Customer percentage	0.39%
MRR	$3,333,333
FP Customer monthly charge	$13,000

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission or other regulatory body accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer, the charges or credits will be passed through using Component 1 of the FP power formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the FP power formula rate.

BR Formula Rate

Component 1

BR Customer Charges = (BR RR × BR %)

Where:

BR RR = BR Monthly Revenue Requirement

BR % = BR percentage for each Customer as indicated in the BR contract after adjustments for hourly exchange energy.

BR Customers will pay for exchange energy by adjusting the BR percentage that is applied to the BR RR. Adjustments to a Customer's BR percentage for seasonal exchanges will be reflected in the Customer's BR contract.

An illustration of the adjustment to a Customer's BR percentage for hourly Exchange Energy (EE) is shown in the table below.

EXAMPLE OF BASE RESOURCE PERCENTAGE ADJUSTMENTS FOR EXCHANGE ENERGY

BR customer	BR percentage from contract	Hourly BR = 30 MWh	Customer's BR in excess of load	Customers receiving EE	BR delivered (adjusting for EE)	Revised BR percentage
Customer A	20	6	3	0	3	10
Customer B	10	3	0	1	4	13.33
Customer C	70	21	0	2	23	76.67
Total	100	30	3	3	30	100

After the FP Customers' share of the annual power revenue requirement has been determined, the remainder of the annual power revenue requirement is recovered from the BR Customers. The BR revenue requirement will be collected in two 6-month periods. For October through March, 25 percent of the BR revenue requirement will be collected. For April through September, 75 percent of the BR revenue requirement will be collected.

A BR RR is calculated by dividing the BR 6-month revenue requirement by six. The revenues from the sale of surplus BR will be applied to the annual BR RR for the following FY.

For January through September 2005, the BR RR will be allocated 25 percent to the 3-month period from January through March 2005 and 75 percent to the 6-month period, April through September 2005.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by the Commission or other regulatory body will be passed on to each appropriate Customer. The Commission or other regulatory body accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer, the charges or credits will be passed through using Component 1 of the BR formula rate.

Component 3

Any charges or credits from the HCA applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the BR formula rate.

Billing: Billing for BR and FP power will occur monthly using the respective formula rate.

Adjustment for Losses: Losses will be accounted for under this rate schedule as stated in the service agreement.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CPP–1

Central Valley Project; Schedule of Rates for Custom Product Power

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers that contract with the Western Area Power Administration (Western) for Custom Product Power.

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

Formula Rate: The Customer will pay all costs incurred in the provision of Custom Product Power. These costs will be passed through to the Customer. The methodology used to calculate the amount of the pass through will be based on the type of funding used to purchase the Custom Product Power. Custom Product Power includes, but is not limited to, supplemental power and Base Resource (BR) firming power.

Advance Funding: Costs for Custom Product Power funded in advance by the Customer(s) will be passed through to that Customer(s) based on the power forecasted for the Customer(s). Unless otherwise agreed to by Western, Custom Product Power funded in advance that is surplus to the load requirements of the Customer(s) will be sold. If the Customer(s) fail to have an account available to receive the proceeds from the sale of surplus Custom Product Power, the proceeds are forfeited to Western and will be applied to the Custom Product Power cost for the Customer(s), to the extent possible.

The table below illustrates the pass through of the Custom Product Power costs for three Customers and the treatment of proceeds from the sale of surplus Custom Product Power. As depicted in the table below, Customers A, B, and C have payment responsibility for a Custom Product Power purchase that was made for them as a group and forecasted for them individually. Customer C must pay for the 3 megawatthours (MWh) even though the Custom Product Power could not be used. The proceeds from the sale of the surplus 3 MWh are deposited into Customer C's account.

CPP COST RECOVERY WITH PROCEEDS FROM SALES OF SURPLUS CPP ADVANCED CUSTOMER FUNDING WITH ACCOUNT

[Western made a CPP purchase of 13 megawatts (MW) for the hour @ $10/MWh=$130]

	CPP forecasted (MWh)	Customer charged for CPP	CPP RR	Surplus CPP sales	Proceeds from excess CPP sales	Proceeds deposited into acct
Customer A	6	$60		0	$0	$0
Customer B	4	40		0	0	0
Customer C	3	30		3	12	12
Total	13	130	$130	3	12	12

Notes:
1. Western sold 3 MWh of CPP at $4/MWh=$12.
2. Proceeds are deposited into Customer C's escrow account because Customer C's CPP amount was surplus.

The table below illustrates the pass through of the Custom Product Power costs for three Customers and the treatment of proceeds from the sale of surplus Custom Product Power for the Customer(s) that have not established an account. As depicted in the table below, all Customers must pay for the Custom Product Power forecasted for them individually. Customer C must pay for the 3 MWh even though the Custom Product Power could not be used by Customer C. The proceeds from the sale of the surplus 3 MWh are used to reduce the Custom Product Power costs for the group to the extent possible, since Customer C does not have an account available for the proceeds. If the costs of the Custom Product Power are fully recovered and proceeds remain from the sale of surplus Custom Product Power, the remaining proceeds will be used to reduce the power revenue requirement.

CPP COST RECOVERY WITH PROCEEDS FROM SALES OF SURPLUS CPP ADVANCED CUSTOMER FUNDING WITHOUT ACCOUNT

[Western made a CPP purchase of 13 MW for the hour @ $10/MWh=$130]

	CPP forecasted (MWh)	CPP cost	Surplus CPP	Proceeds from excess CPP sales	Charge per customer
Customer A	6	$60	0		$54.46
Customer B	4	40	0		36.31
Customer C	3	30	3		$27.23
Total	13	130	3	$12	$118.00

Notes:
1. Western sold 3 MWh of surplus CPP at $4/MWh = $12.
2. Proceeds reduce the CPP cost because no account is available for the proceeds of the sale of surplus CPP.
3. Proceeds from surplus sales reduce CPP costs and are allocated to each Customer based on the amount of CPP forecasted.

Use of Receipts, Federal Reimbursable, or Appropriations Authority:

If the Custom Product Power is funded through appropriations, Federal reimbursable, or use of receipts authority, the cost of the Custom Product Power is passed through to the Customer(s) that have this power in their final schedule. Custom Product Power funded through appropriations, Federal reimbursable, or use of receipts authority that is surplus to the load requirements of the Customer(s) will be sold. Proceeds from the sale of surplus Custom Product Power funded through use of receipts, Federal reimbursable, or appropriations authority will be applied to the Custom Product Power purchase cost for the Customer(s) to the extent possible. If the cost of the Custom Product Power is fully recovered and proceeds remain from the sale of surplus Custom Product Power, the remaining proceeds will be used to reduce the power revenue requirement. The table below illustrates the pass through of the Custom Product Power costs to each Customer and the treatment of proceeds from the sale of surplus Custom Product Power funded through appropriations, Federal reimbursable, or use of receipts authority. As shown, Customers A and B are responsible for paying the full costs of the Custom Product Power purchase made by Western (Total Custom Product Power revenue requirement is $130) because they are the only Customers that had the Custom Product Power in their final schedules. The Custom Product Power revenue requirement of $130 is reduced by the sales of $12, which reduces the Custom Product Power revenue requirement to $118. Therefore, the reduced Custom Product Power revenue requirement of $118 is prorated to each Customer based on the amount of Custom Product Power in their final schedules.

CPP COST RECOVERY WITH PROCEEDS FROM SALES OF SURPLUS CPP USE OF RECEIPTS, FEDERAL REIMBURSABLE, OR APPROPRIATIONS AUTHORITY

[Western made a CPP purchase of 13 MW for the hour @ $10/MWh = $130]

	CPP purchased (MWh)	CPP used (MWh)	CPP costs	Surplus CPP sold	Proceeds from excess CPP sales	CPP customer charges
Customer A	6	6		0		$70.80
Customer B	4	4		0		47.20
Customer C	3	0		3		0.00
Total	13	10	$130	3	$12	118.00

Notes:
1. Western sold 3 MWh of CPP at $4/MWh = $12.
2. Proceeds from the sale of surplus CPP reduce the CPP Costs prorated based on the amount of CPP used.

Western will charge $31.07 per schedule per day to cover its administrative costs for procuring and scheduling Custom Product Power if the Customer has not contracted with Western for this type of service through other agreements. If the actual number of schedules for the month is not available, Western will estimate the number of schedules for the month and apply the $31.07 per schedule charge to the estimated number of schedules.

Billing: Billing for Custom Product Power will occur monthly using the formula rate.

Adjustments for Losses: All losses incurred for delivery of Custom Product Power under this rate schedule shall be the responsibility of the Customer that has contracted for this service.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–T1 (Supersedes Schedules CV–FT4 and CV–NFT4)

Central Valley Project; Schedule of Rate for Transmission Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving Central Valley Project (CVP) firm and/or non-firm transmission service.

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

Formula Rate: The formula rate for CVP firm and non-firm transmission service includes three components:

Component 1

$$\frac{\text{CVP TRR}}{\text{TTc} + \text{NITSc}}$$

Where:

CVP TRR = Transmission Revenue Requirement is the costs associated with facilities that support the transfer capability of the CVP transmission system, excluding generation facilities and radial lines.

TTc = Total Transmission Capacity is the total transmission capacity under long-term contract between the Western Area Power Administration (Western) and other parties.

NITSc = Average 12-month coincident peaks of network integrated transmission service (NITS) Customers at the time of the monthly CVP transmission system peak. For rate design purposes, Western's use of the transmission system to meet its statutory obligations is treated as NITS.

Western will revise the rate from Component 1 based on either of the following two conditions: (a) Updated financial data available in March of each year, and (b) a change in the numerator or denominator that results in a rate change of at least $0.05 per kilowattmonth. Rate change notifications will be posted on the Open Access Same-Time Information System.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission or other regulatory body accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP transmission service formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP transmission service formula rate.

Billing: The formula rate above applies to the maximum amount of capacity reserved for periods ranging from 1 hour to 1 month, payable whether used or not. Billing will occur monthly.

Adjustment for Losses: Losses incurred for service under this rate schedule will be accounted for as agreed to by the parties in accordance with the service agreement.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–NWT3 (Supersedes Schedule CV–NWT2)

Central Valley Project; Schedule of Rate for Network Integration Transmission Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers who receive Central Valley Project (CVP) Network Integration Transmission Service (NITS), to points of delivery and receipt as specified in the service agreement.

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

Formula Rate: The formula rate for CVP NITS includes three components:

Component 1

NITS Customer's monthly demand charge = NITS Customer's load ratio share times one-twelfth (1/12) of the Annual Network TRR.

Where:

NITS Customer's load ratio share = The NITS Customer's hourly load (including behind the meter generation minus the NITS Customer's hourly Base Resource) coincident with the monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved transmission capacity) transmission service, expressed as a ratio.

Annual Network TRR = Total CVP transmission revenue requirement, less revenues from long-term contracts for CVP transmission between the Western Area Power Administration (Western) and other parties.

The Annual Network TRR will be revised when the rate from Component 1 of the CVP transmission rate under Rate Schedule CV–T1 is revised.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Commission or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP NITS formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP NITS formula rate.

Billing: NITS will be billed monthly under the formula rate.

Adjustment for Losses: Losses incurred for service under this rate schedule will be accounted for as agreed to by the parties in accordance with the service agreement.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule COTP–T1 (Supersedes Schedules COTP–FT2 and COTP NFT–2)

California-Oregon Transmission Project; Schedule of Rate for Transmission Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving California-Oregon Transmission Project (COTP) firm and/or non-firm transmission service.

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

Formula Rate: The formula rate for COTP firm and non-firm transmission service includes three components:

Component 1

$$\frac{\text{COTP TRR}}{\text{Western's COTP Seasonal Capacity}}$$

Where:

COTP TRR = COTP Seasonal Transmission Revenue Requirement (the Western Area Power Administration's (Western) costs associated with facilities that support the transfer capability of the COTP).

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

Western will update the rate from Component 1 of the formula rate for COTP firm transmission service at least 15 days before the start of each COI rating season. Rate change notifications will be posted on the Open Access Same-Time Information System.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the COTP transmission service formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the COTP transmission service formula rate.

Billing: The formula rate above applies to the maximum amount of capacity reserved for periods ranging from 1 hour to 1 month, payable whether used or not. Billing will occur monthly.

Adjustment for Losses: Losses incurred for service under this rate schedule will be accounted for as agreed to by the parties in accordance with the service agreement.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule PACI–T1

Pacific Alternating Current Intertie Project; Schedule of Rate for Transmission Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving the Pacific Alternating Current Intertie (PACI) firm and/or non-firm transmission service.

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

Formula Rate: The formula rate for PACI firm and non-firm transmission service includes three components:

Component 1

$$\frac{\text{PACI TRR}}{\text{Western's PACI Seasonal Capacity}}$$

Where:

PACI TRR = PACI Seasonal Transmission Revenue Requirement, the Western Area Power Administration's (Western) costs associated with facilities that support the transfer capability of the PACI.

Western's PACI Seasonal Capacity = Western's share of PACI capacity (subject to curtailment) under the then current California-Oregon Intertie (COI) transfer capability for the season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Western will update the rate from Component 1 of the formula rate for PACI firm transmission service at least 15 days before the start of each COI rating season. Rate change notifications will be posted on the Open Access Same-Time Information System.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the PACI transmission service formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer, the charges or credits will be passed through using Component 1 of the PACI transmission service formula rate.

Billing: The formula rate above applies to the maximum amount of capacity reserved for periods ranging from 1 hour to 1 month, payable whether used or not. Billing will occur monthly.

Adjustment for Losses: Losses incurred for service under this rate schedule will be accounted for as agreed to by the parties in accordance with the service agreement.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–TPT6 (Supersedes CV–TPT5)

Central Valley Project; Schedule of Rate for Transmission of Western Power by Others

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To the Western Area Power Administration's (Western) power service Customers who require transmission service by a third party to receive power sold by Western.

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

Formula Rate

Component 1

When Western uses transmission facilities other than its own in supplying Western power, and costs are incurred by Western for the use of such facilities, the Customer will pay all costs, including transmission losses, incurred in the delivery of such power.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the third-party transmission service formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer, the charges or credits will be passed through using Component 1 of the third-party transmission service formula rate.

Billing: Third-party transmission will be billed monthly under the formula rate.

Adjustments for Losses: All losses incurred for delivery of power under this rate schedule shall be the responsibility of the Customer that received the power.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–SPR3 (Supersedes Schedule CV–SPR2)

Central Valley Project; Schedule of Rate for Spinning Reserve Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving spinning reserve service.

Character and Conditions of Service: Spinning reserve service supplies capacity that is available immediately to take load and is synchronized with the power system.

Formula Rate: The provisional formula rate for spinning reserve service is the price consistent with the California Independent System Operator's market plus all costs incurred as a result of the sale of spinning reserves, such as: (1) The Western Area Power Administration's (Western) scheduling costs, (2) any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body to which this rate methodology applies, and (3) any charges or credits from the Host Control Area applied to Western for providing this service.

For Customers that have a contractual obligation to provide spinning reserve service to Western and do not fulfill that obligation, the penalty for nonperformance will be the greater of actual costs or 150 percent of the market price.

Billing: The formula rate above will be applied to the amount of spinning reserve sold. Billing will occur monthly.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to formula rate in this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–SUR3 (Supersedes Schedule CV–SUR2)

Central Valley Project; Schedule of Rate for Non-Spinning Reserve Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving non-spinning reserve service.

Character and Conditions of Service: Non-spinning reserve service supplies capacity that is available within the first 10 minutes to take load and is synchronized with the power system.

Formula Rate: The provisional formula rate for non-spinning reserve service is the price consistent with the California Independent System Operator's market plus all costs incurred as a result of the sale of spinning reserves, such as: (1) The Western Area Power Administration's (Western) scheduling costs, (2) any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission or other regulatory body to which this rate methodology applies, and (3) any charges or credits from the Host Control Area applied to Western for providing this service.

For Customers with a contractual obligation to provide non-spinning reserve service to Western and who do not fulfill that obligation, the penalty for nonperformance will be the greater of actual costs or 150 percent of the market price.

Billing: The formula rate above will be applied to the amount of non-spinning reserve sold. Billing will occur monthly.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to formula rate under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–RFS3 (Supersedes Schedule CV–RFS2)

Central Valley Project; Schedule of Rate for Regulation and Frequency Response Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving Regulation and Frequency Response Service (Regulation).

Character and Conditions of Service: Regulation is necessary to provide for the continuous balancing of resources and interchange with load and for maintaining scheduled interconnection frequency at 60 cycles per second.

Formula Rate: The provisional formula rate for Regulation includes three components:

Component 1

$$\frac{\text{Annual Revenue Requirement}}{\text{Annual Regulating Capacity kW}}$$

The annual regulating capacity is the total regulating capacity bandwidths provided by the Western Area Power Administration (Western) under the interconnected operations agreements with sub-control area (SCA) members. The penalty for nonperformance by an SCA Customer that has committed to self-provision for its regulating capacity requirement will be the greater of actual costs or 150 percent of the market price.

Western will revise the rate resulting from Component 1 based on either of the following two conditions: (a) updated financial data available in March of each year, and (b) a change in the numerator or denominator that results in a rate change of at least $0.25 per kilowattmonth.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the regulation and frequency response service formula rate.

Component 3

Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the Regulation formula rate.

Billing: The formula rate above will be applied to the regulating capacity bandwidth contained in the service agreement. Billing will occur monthly.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the revenue requirement under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–EID3 (Supersedes Schedule CV–EID2)

Central Valley Project Schedule of Rate for Energy Imbalance Service

Effective: January 1, 2005, through September 30, 2009.

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

Applicable: To Customers receiving energy imbalance service.

Character and Conditions of Service: Energy imbalance service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load or from a generation resource over an hour. The hourly deviation, in megawatts, is the net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.

Energy imbalance service uses the regulating capacity bandwidth that is established in the service agreement.

Formula Rate: The formula rate for Energy Imbalance Service has three components:

Component 1

An hourly average negative deviation (underdelivery) outside the regulating capacity bandwidth will be charged the greater of 150 percent of market price or actual cost. An hourly average positive deviation (overdelivery) outside the bandwidth is lost to the system.

Component 2

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

To the extent possible, the Western Area Power Administration (Western) will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited.

Component 3

Any charges or credits from the Host Control Area applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible.

Billing: Billing for average hourly negative deviations outside the bandwidth will occur monthly.

Adjustment for Audit Adjustments: Financial audit adjustments that apply to the formula rate under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

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