SCHEDULE FOR DRAFT EIS/EIR PUBLIC MEETINGS

[**Note:** All meetings will last for 1 hour, or until the submission of public comments is concluded (whichever occurs later).]

Date & time	Community	Location
Monday, April 3, 2000, 1:30 pm	Upper Moenkopi, AZ	Moenkopi Community Building.
Wednesday,* April 5, 2000, 5:00 pm	Kayenta, AZ	Kayenta Chapter House.
Thursday, April 6, 2000, 7:00 pm	Farmington, NM	Holiday Inn, 600 East Broadway, Animas Room.
	Fullerton, CA	Four Points Sheraton, 1500 South Raymond Avenue, Crown 1 Room.
Monday, April 10, 2000, 7:00 pm	Long Beach, CA	Los Cerritos Elementary School, 515 West San Antonio Drive, Auditorium.
Tuesday, April 11, 2000, 6:00 pm	Banning, CA	Banning Council Chambers, 99 East Ramsey Street.

* Date and time subject to final approval of the Kayenta Chapter. Local media and on-site announcements will advise residents of any changes to the Kayenta meeting schedule.

[FR Doc. 00–5027 Filed 3–2–00; 8:45 am]
BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Western Area Power Administration

Proposed Rates for Central Valley and California-Oregon Transmission Projects

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed rates.

SUMMARY: Western Area Power Administration (Western) is proposing rates for Central Valley Project (CVP) commercial firm power, power scheduling, scheduling coordinator, CVP transmission, transmission of CVP power by others, network transmission, California-Oregon Transmission Project (COTP) transmission and ancillary services. Current rates expire September 30, 2002. The proposed rates will provide sufficient revenue to repay all annual costs, including interest expense, and repay required investment within the allowable period. Rate impacts are detailed in a rate brochure to be provided to all interested parties. Proposed rates are scheduled to go into effect on October 1, 2000, to correspond with the start of the Federal fiscal year (FY), and will remain in effect through December 31, 2004, which is the end of the current (1994) CVP Power Marketing Plan. This **Federal Register** notice initiates the formal process for the proposed rates.

DATES: The consultation and comment period will begin today and will end June 2, 2000. Western will present a detailed explanation of these proposed rates at a public information forum on March 14, 2000, at 1 p.m. PST, and will receive oral and written comments at a public comment forum on April 18, 2000, at 1 p.m., see the **ADDRESSES** section. Western must receive all comments by the end of the consultation and comment period to assure consideration of the comments.

ADDRESSES: Send written comments to Mr. Jerry W. Toenyes, Regional Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710.

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

SUPPLEMENTARY INFORMATION: Proposed rates for CVP commercial firm power are designed to recover an annual revenue requirement that includes the investment repayment, interest, purchase power, transmission and operation and maintenance expense. A cost of service study allocates the projected annual revenue requirement for commercial firm power between capacity and energy. Capacity revenue requirement includes: (i) 100 percent of capacity purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; (iv) 50 percent of the power operation and maintenance expense allocated to power; and (v) 100 percent of CVP and COTP transmission expense. Projected CVP and COTP transmission revenue and 50 percent of projected CVP project use revenue reduce the annual costs that determine the capacity revenue requirement. The energy revenue requirement includes: (i) 100 percent of energy purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; and (iv) 50 percent of the power operation and maintenance expense allocated to power. Projected surplus power revenue, and 50 percent of projected CVP project use revenue reduce annual costs to determine the energy revenue requirement. The resulting capacity/energy revenue requirement split varies from 27 percent allocated to capacity from October 2003 through December 2004 to 38 percent allocated to capacity in FY 2001. The average capacity/energy revenue requirement split for the rate period is 32 percent to capacity and 68 percent to energy.

Western also developed proposed rates for CVP commercial firm power with the transmission revenue requirement removed from the commercial firm power revenue requirement. These rates would apply if Western joins the California Independent System Operator (CAISO) and if the CAISO uses the transmission revenue requirement to develop a regional transmission rate. Western has not made a decision on joining the CAISO. The decision to join the CAISO is not part of this rate adjustment public process. These proposed power rates with the transmission revenue requirement removed are designed to recover an annual revenue requirement that includes investment repayment, interest, purchase power and operation and maintenance expense. A cost of service study allocates projected annual revenue requirement for firm power between capacity and energy. Capacity revenue requirement includes: (i) 100 percent of capacity purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; and (iv) 50 percent of the power operation and maintenance expense allocated to power. Fifty percent of the projected CVP project use revenue reduces the annual cost to determine the capacity revenue requirement. Energy revenue requirement includes: (i) 100 percent of energy purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; and (iv) 50 percent of the power operation and maintenance expense allocated to power. Projected surplus power revenue, and 50 percent of the projected CVP project use revenue reduce the annual cost to determine the energy revenue requirement. The resulting capacity/energy revenue requirement split varies from 21 percent allocated to capacity during October 2003 through December 2004 to 30 percent allocated to capacity in FY 2001. The average capacity/energy revenue requirement split for the rate period is 25 percent to capacity and 75 percent to energy.

Both sets of proposed rates, *i.e.,* the proposed rates for the CVP commercial firm power and the proposed rates for CVP commercial firm power with the transmission revenue requirement removed, include an Annual Energy Rate Alignment (AERA). Western will apply the AERA to firm energy purchased at or above an average annual load factor of 80 percent. The AERA is set to ensure that customers would pay at least the equivalent of the CVP composite rate for purchases from Western. The billing for the AERA will occur at the end of each FY.

Both sets of proposed rates also include a tier capacity rate. Western will apply the tier capacity rate to monthly capacity purchases at or above 90 percent of the customers' Contract Rate of Delivery (CRD). The tier capacity factor of 90 percent is an approximation based on the ratio of the sum of CVP Project Dependable Capacity, Northwest capacity credit and minimum monthly Pacific Gas and Electric Company capacity purchases to Western's system simultaneous load level.

Proposed rates for CVP commercial firm power, the applicable revenue requirement split between capacity and energy, tier capacity rate and AERA are in Table 1.

TABLE 1.—PROPOSED COMMERCIAL FIRM POWER RATES

Effective period	Total composite mills/kWh	Capacity $/kWmo	Energy mills/kWh	Capacity/energy split	Tier capacity $/kWmo	AERA mills/kWh
10/01/00 to 09/30/01	15.37	3.33	9.49	38/62	5.16	5.50
10/01/01 to 09/30/02	15.77	2.95	10.52	33/67	5.29	5.25
10/01/02 to 09/30/03	18.65	2.98	13.33	29/71	5.42	5.00
10/01/03 to 12/31/04	20.80	3.12	15.32	27/73	5.58	5.00

The proposed rates for CVP commercial firm power with the transmission revenue requirement removed, applicable revenue requirement split between capacity and energy, tier capacity rate and AERA are in Table 1A.

TABLE 1A.—PROPOSED COMMERCIAL FIRM POWER RATES WITH THE TRANSMISSION REVENUE REQUIREMENT REMOVED FROM THE COMMERCIAL FIRM POWER REVENUE REQUIREMENT

Effective period	Total composite mills/kWh	Capacity $/kWmo	Energy mills/kWh	Capacity/energy split	Tier capacity $/kWmo	AERA mills/kWh
10/01/00 to 09/30/01	13.55	2.23	9.49	30/70	5.16	5.50
10/01/01 to 09/30/02	14.22	2.00	10.52	26/74	5.29	5.25
10/01/02 to 09/30/03	17.12	2.05	13.33	22/78	5.42	5.00
10/01/03 to 12/31/04	19.20	2.14	15.32	21/79	5.58	5.00

The Deputy Secretary of the Department of Energy (DOE), approved the existing Rate Schedule CV–F9 for CVP commercial firm power on September 19, 1997 (Rate Order No. WAPA–77, 62 FR 50924, September 29, 1997). The Federal Energy Regulatory Commission (FERC) confirmed and approved the rate schedule on January 8, 1998, under FERC Docket No. EF97–5011–000 (82 FERC ¶ 62,006). The existing Rate Schedule CV–F9 became effective on October 1, 1997, for the period ending September 30, 2002. Under Rate Schedule CV–F9, the composite rate on October 1, 2000, is 18.56 mills per kilowatthour (mills/kWh), the base energy rate is 10.51 mills/kWh, the AERA energy rate is 4.09 mills/kWh and the capacity rate is $3.81 per kilowattmonth (kWmo). The proposed rates for CVP commercial firm power will result in an overall composite rate decrease of approximately 17 percent on October 1, 2000, when compared with the current CVP commercial firm power rates under Rate Schedule CV–F9. Table 2 provides a comparison of the current rates in Rate Schedule CV–F9 and the proposed rates along with the percentage change in the rates.

TABLE 2.—COMPARISON OF CURRENT AND PROPOSED RATES[1]

Effective period	Total composite rate	Percent change	Base capacity $/kWmo	Percent change	Base energy mills/kWh	Percent change	AERA mills/kWh	Percent change
Percentage change in commercial firm power rates								
Current Rate Schedule								
Existing 10/01/00 to 09/30/01	18.56	....	3.81	....	10.51	....	4.09	....
Proposed Rates								
10/01/00 to 09/30/01	15.37	−17	3.33	−13	9.49	−10	5.50	34
10/01/01 to	15.77	−15	2.95	−23	10.52	....	5.25	28
10/01/02 to 09/30/03	18.65	....	2.98	−22	−13.33	27	5.00	22
0/01/03 to 12/31/04	20.80	12	3.12	−18	15.32	46	5.00	22

[1] The percent changes do not include the impacts of the tier capacity rates.

The proposed rates for CVP commercial firm power with the transmission revenue requirement removed will result in an overall composite rate decrease of approximately 27 percent on October 1, 2000, when compared with the current CVP commercial firm power rates under Rate Schedule CV–F9. Table 2A provides a comparison of the current rates in Rate Schedule CV–F9 and the proposed rates along with the percentage change in the rates.

TABLE 2A.—COMPARISON OF CURRENT AND PROPOSED RATES WITH THE TRANSMISSION REVENUE REQUIREMENT REMOVED [2]

Effective period	Total composite rate	Percent change	Capacity $/kWmo	Percent change	Base energy mills/kWh	Percent change	AERA mills/kWh	Percent change
Percentage change in commercial firm power rates								
Current Rate Schedule								
Existing 10/01/00 to 09/30/01	18.56	....	3.81	....	10.51	....	4.09	....
Proposed Rates with the transmission revenue requirement removed								
10/01/00 to 09/30/01	13.55	−27	2.23	−41	9.49	−10	5.50	34
10/01/01 to 09/30/02	14.22	−23	2.00	−48	10.52	....	5.25	28
10/01/02 to 09/30/03	17.12	−8	2.05	−46	13.33	27	5.00	22
10/01/03 to 12/31/04	19.20	3	2.14	−44	15.32	46	5.00	22

[2] The percent changes do not include the impacts of the tier capacity rates. These rates do not include the cost of transmission, therefore, the customer is required to buy transmission at an additional cost.

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

Power Factor Adjustment

This provision in Rate Schedule CV–F9, will remain the same under the proposed rates for CVP commercial firm power.

Low Voltage Loss Adjustment

This provision in Rate Schedule CV–F9, will remain the same under the proposed rates for CVP commercial firm power.

Revenue Adjustment

The Revenue Adjustment Clause (RAC) provides for a comparison between the projected net revenues in the rate adjustment power repayment study to the actual net revenues. If the actual net revenue is more than the projected net revenue, CVP preference customers receive a credit. If actual net revenue is less than the projected net revenue, CVP preference customers may pay a surcharge, if needed, to make a minimum investment payment. The limit for the RAC credit or surcharge is $20 million, plus any purchase power contract adjustments during the FY for which the RAC is being calculated. The RAC is calculated annually and the associated distribution of the RAC credit or surcharge occurs during a 9-month period on power bills issued in January through September. For customers whose RAC credits cannot be fully credited through nine equal monthly amounts, Western has the option to increase the RAC credit during August and September.

Proposed Rate for Power Scheduling Service

The proposed rate for power scheduling service is $84.38 per hour and is based on costs incurred to provide the service. Power scheduling service provides for scheduling resources to meet load and reserve requirements.

Proposed Rate for Scheduling Coordinator Service

The proposed rate for scheduling coordinator service is $75.54 per hour and is based on costs incurred to provide the service. Scheduling coordinator service provides scheduling, real-time dispatching and financial settlements with the CAISO.

Proposed Formula Rate for CVP Transmission

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

$$\text{Component 1: } \frac{\text{transmission revenue requirement}}{(\text{CVP capacity } + \text{ total transmission capacity under long term contracts}).}$$

Component 1 is the ratio of Western's transmission revenue requirement to the sum of the maximum operating capacity of the Northern CVP power plants (CVP capacity) and the total transmission capacity under long-term contract between Western and other parties. Northern CVP power plants are J.F. Carr, Folsom, Keswick, Nimbus, Shasta, Spring Creek and Trinity.

Component 2: Pass through of any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The costs in Component 2, as well as any changes to these costs, will be directly passed through to each appropriate transmission customer.

Western will revise the rate resulting from Component 1 of the proposed formula rate based on: (i) Updated data as of April 30 of each year; and (ii) a change in the numerator or denominator that results in a rate change of at least $.05 per kWmo. The rate resulting from the proposed formula rate for firm CVP transmission for FY 2001 is $0.73 per kWmo, a 43-percent increase from the existing rate of $0.51 per kWmo, under Rate Schedule CV–FT3. Based on a contract agreement to provide transmission service in the future, the rate resulting from the proposed formula rate for firm CVP transmission for FY 2002 is $.58 per kWmo, a 14-percent increase from the existing rate of $.51 per kWmo.

The rate resulting from the proposed formula rate for nonfirm CVP transmission service for FY 2001 is 1.00 mill/kWh. The proposed formula rate for nonfirm CVP transmission is based on the same two components used in the proposed formula rate for firm CVP transmission. Firm or nonfirm transmission service for 1 year or less may be at rates lower than the rates resulting from the proposed formula rate if these cost-based rates are higher than the current rate for transmission sales.

The proposed formula rate for CVP transmission service is based on a revenue requirement that recovers: (i) The CVP transmission system costs for facilities associated with providing all transmission service; (ii) the nonfacilities costs allocated to transmission service; and (iii) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The proposed formula rate includes Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control associated with the transmission service. The proposed formula rate is applicable to existing CVP firm transmission service and future point-to-point transmission service.

Proposed Rate for Transmission of CVP Power by Others

Western will directly pass through transmission service costs it incurs for delivering CVP power over a third party's transmission system to the requesting CVP customer. Rates under this schedule are proposed to be automatically adjusted as third party transmission costs are adjusted.

Proposed Formula Rate for Network Transmission

If Western offers network transmission service, its proposed formula rate is the product of the network customer's load ratio share times one-twelfth of the annual network transmission revenue requirement. The load ratio share is the network customer's hourly load coincident with Western's monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved capacity) point-to-point transmission service. The proposed formula rate for network transmission service is based on a revenue requirement that recovers: (i) CVP transmission system costs for facilities associated with providing all transmission service; (ii) the nonfacilities costs allocated to transmission service; and (iii) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The proposed formula rate includes Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control needed to provide the transmission service.

Proposed Formula Rate for COTP Transmission

The proposed formula rate for COTP transmission includes two components.

$$\text{Component 1: } \frac{\text{Transmission Revenue Requirement}}{\text{Western's share of COTP Seasonal Capacity}}$$

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

Component 2: Pass through of any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The costs in Component 2, as well as any changes to these costs, will be directly passed through to each appropriate transmission customer.

The rates resulting from the proposed formula rate for firm COTP transmission service for FY 2001 are: summer—$1.47 per kWmo, winter—$1.66 per kWmo and spring—$1.53 per kWmo. These rates resulting from the proposed formula rate result in a 10-percent increase during the summer, a 24-percent increase during the winter and a 14-percent increase during the spring compared to the existing rate of $1.34 per kWmo.

The proposed formula rate for nonfirm COTP transmission is based on the same two components used in the proposed formula rate for firm COTP transmission. Rates resulting from the proposed formula rate for nonfirm transmission service for FY 2001 are: summer—2.01 mills/kWh, winter—2.28 mills/kWh and spring—2.10 mills/kWh. These rates for nonfirm COTP transmission service result in a 39-percent increase during the summer, a 57-percent increase during the winter and a 45-percent increase during the spring compared to the existing rate of 1.45 mills/kWh. Firm or nonfirm transmission service for 1 year or less may be at rates lower than the rates resulting from the proposed formula rate if these cost-based rates are higher than the current rate for transmission sales.

Rates resulting from the proposed formula rate for COTP transmission service are based on a revenue requirement that recovers: (i) Western's share of COTP transmission system costs for facilities associated with providing all transmission service; (ii) Western's share of the nonfacilities costs allocated to transmission service; and (iii) any transmission-related costs incurred by Western due to electric industry restructuring or other changes in the industry. The rates resulting from the proposed formula rate include Western's cost for scheduling, system control and dispatch service and reactive supply and voltage control associated with transmission service. The proposed formula rate would apply to existing COTP transmission service and future point-to-point transmission service.

Proposed Rates for Ancillary Services

Western will provide ancillary services, subject to availability, at the proposed rates in Table 3. Western designed these proposed rates to recover only the costs it incurs for providing the service(s). Sales of ancillary services of 1 year or less may be at rates lower than the proposed rates if these cost-based rates are higher than the current rate for ancillary service sales.

TABLE 3.—PROPOSED RATES FOR ANCILLARY SERVICES

Ancillary service type	Rate
Transmission Scheduling, System Control and Dispatch Service—required to schedule movement of power through, out of, within, or into a control area.	Appropriate transmission rates include Western's cost.
Reactive Supply and Voltage Control—reactive power support provided from generation facilities necessary to maintain transmission voltages within acceptable limits of the system.	Appropriate transmission rates include Western's cost.
Regulation and Frequency Response Service—provides generation to match resources and loads on a real-time continuous basis.	Monthly: $1.78 per kWmonth. Weekly: $0.42 per kWweek. Daily: $0.06 per kWday.
Energy Imbalance Service—provided when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month.	*Within Limits of Deviation Band:* Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP commercial firm power then in effect.
Hourly Deviation (MW)—net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.	*Outside Limits of Deviation Band:* (i) Positive Deviations—The greater of no charge, or any additional cost incurred. (ii) Negative Deviations—during on-peak hours, the greater of 3 times the proposed rates for CVP commercial firm power or any additional cost incurred. During off-peak hours, the greater of the proposed rates for CVP commercial firm power or any additional cost incurred.
Spinning Reserve Service—provides capacity available the first 10 minutes to take load and is synchronized with the power system.	Monthly: $1.95 per kWmonth. Weekly: $0.42 per kWweek. Daily: $0.06 per kWday. Hourly: $0.0027 per kWh.
Supplemental Reserve Service—provides capacity not synchronized, but can be available to serve loads within 10 minutes.	Monthly: $1.77 per kWmonth. Weekly: $0.42 per kWweek. Daily: $0.06 per kWday. Hourly: $0.0024 per kWh.

Since the proposed rates constitute a major rate adjustment as defined by the procedures for public participation in general rate adjustments, as cited below, Western will hold both a public information forum and a public comment forum. After reviewing public comments, Western will recommend the Deputy Secretary of DOE approve the proposed rates (and as amended) on an interim basis.

Legal Authority

These proposed rates for CVP and COTP power, transmission and power-related services are being established pursuant to the DOE Organization Act, 42 U.S.C. 7101–7352; the Reclamation Act of 1902, ch. 1093, 32 Stat. 388, as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. 485h(c); and other acts that specifically apply to the projects involved.

By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary of Energy delegated (1) The authority to develop long-term power and transmission rates on a nonexclusive basis to Western's Administrator; and (2) the authority to confirm, approve and place into effect on a final basis, to remand, or to disapprove such rates to FERC. In Delegation Order No. 0204–172, effective November 24, 1999, the Secretary of Energy delegated the authority to confirm, approve and place such rates into effect on an interim basis to the Deputy Secretary. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) became effective on September 18, 1985 (50 FR 37835).

Availability of Information

All brochures, studies, comments, letters, memoranda, or other documents made or kept by Western for developing the proposed rates, are available for inspection and copying at the Sierra Nevada Regional Office, located at 114 Parkshore Drive, Folsom, California 95630–4710.

Regulatory Procedural 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 applies to rates or services for 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 parts 1500–1508); and DOE NEPA Regulations (10 CFR part 1021), Western has determined that this action is categorically excluded from the preparation of an environmental assessment or an environmental impact statement.

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.

Dated: February 18, 2000.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 00–5168 Filed 3–2–00; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6546–9]

Access to Confidential Business Information by Booz-Allen, & Hamilton, Inc.

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: EPA is authorizing Booz-Allen, & Hamilton, Inc. to participate in reviews of selected Superfund cost recovery documentation and records management. During the review, the contractor will have access to information which has been submitted to EPA under section 104 of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). Some of this information may be claimed or determined to be Confidential Business Information (CBI).

DATES: The contractor (Booz-Allen, & Hamilton, Inc.) will have access to this data five working days from the date of this notice.

ADDRESSES: Send or deliver, written comments to Veronica Kuczynski, U.S. Environmental Protection Agency, Office of the Comptroller (3PM30), 1650 Arch Street, Philadelphia, Pennsylvania 19103.

FOR FURTHER INFORMATION CONTACT: Veronica Kuczynski, Office of the Comptroller, (3PM30), 1650 Arch Street, Philadelphia, Pennsylvania 19103, Telephone (215) 814–5169.

SUPPLEMENTARY INFORMATION: Under EPA Interagency Agreement with General Services Administration, Contract GSOOT96AHD0002, Task Order #19990712, Booz-Allen, & Hamilton, Inc. will be conducting an on-site review of the procedures and systems currently in place for compliance with Superfund cost recovery and record keeping requirements in the State of Maryland. This review involves conducting transaction testing to evaluate recipient conformance with applicable regulations and acceptable business practices and documenting findings. The contractor will examine transactions for the following:

(1) Expenditures Review: expenditure documentation such as expense reports, timesheets, and purchase requests from the point of origination to the point of payment to determine compliance with such requirements as site-specific accounting data, authorizing signature and reconciliation of timesheets to expense reports.

(2) Financial Reports: review financial drawdowns, Financial Status Reports, and internal status reports, to determine if information is consistent between these documents, if recipient is properly using information, and if the reports are submitted when required.

(3) Recordkeeping Procedures: review samples of Superfund documentation to determine the effectiveness of the recipient procedures to manage and reconcile this documentation (focusing on site-specific documentation, retention schedules, and the ability of the recipient to provide EPA with required financial documentation for cost recovery purposes in the specified time frame).

In providing this support, Booz-Allen, & Hamilton, Inc., employees may have access to recipient documents which potentially include financial documents submitted under section 104 of CERCLA, some of which may contain information claimed or determined to be CBI.

Pursuant to EPA regulations at 40 CFR part 2, subpart B, EPA has determined that Booz-Allen, & Hamilton, Inc., requires access to CBI to provide the support and services required under the Delivery Order. These regulations provide for five working days notice before contractors are given access to CBI.

Booz-Allen, & Hamilton, Inc. will be required by contract to protect confidential information. These documents are maintained in recipient office and file space.

Dated: February 24, 2000.

Bradley M. Campbell,

Regional Administrator, Region III.

[FR Doc. 00–5204 Filed 3–2–00; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–6251–7]

Environmental Impact Statements and Regulations; Availability of EPA Comments

Availability of EPA comments prepared February 14, 2000 Through February 18, 2000 pursuant to the Environmental Review Process (ERP), under Section 309 of the Clean Air Act and Section 102(2)(c) of the National Environmental Policy Act as amended. Requests for copies of EPA comments can be directed to the Office of Federal Activities at (202) 564–7167. An explanation of the ratings assigned to draft environmental impact statements (EISs) was published in FR dated April 9, 1999 (63 FR 17856).

Draft EISs

ERP No. D–AFS–J65310–00 Rating EC2, Dakota Prairie Grasslands, Nebraska National Forest Units and Thunder Basin National Grassland, Land and Resource Management Plans 1999 Revisions, Implementation, MT, NB, WY, ND and SD.

Summary: EPA expressed concern that as the public dialogue takes place on roadless areas that an interim plan be in place that reserves current roadless areas until a plan is in place. EPA requested that a section be added to discuss the government-to-government consultation process with affected Indian Tribes and that stipulations on oil and gas leases require pits to be netted. EPA also suggested that portions of the Little Missouri River that course through the Grasslands be proposed for scenic and/or wild designation.

ERP No. D–AFS–K65224–AZ Rating EC2, Williams Ski Area Expansion on Bill Williams Mountain, Implementation, Special-Use-Permit, Kaibab National Forest, Williams Ranger District, Coconino County, AZ.

Summary: EPA expressed concerns with the potential for the proposed project to impact water and cultural resources. EPA requested that the FEIS more thoroughly address those issues and discuss the consultation process with affected tribes.

ERP No. D–BLM–K39058–CA Rating EO2, Cadiz Groundwater Storage and Dry-Year Supply Program, Construction and Operation, Amendment of the California Desert Conservation Area (CDCA) Plan, Issuance of Right-of-Way Grants and Permits, San Bernardino County, CA.

Summary: EPA objected to the project based on the potential significant impacts and the lack of an air conformity determination. The project would also adversely affect many ephemeral washes and other sensitive habitats, but mitigation measures do not appear sufficient to protect resources. EPA recommended that a draft conformity determination be issued prior to issuance of the FEIS.

ERP No. D–BOP–E80002–SC Rating EC2, South Carolina—Federal Correctional Institution, Construct and Operate, Possible Sites: Andrew, Bennettsville, Oliver and Salters, SC.