Energy Organization Act, Public Law 95–91, dated August 4, 1977, and Southwestern's power marketing activities were transferred from the Department of Interior to the Department of Energy, effective October 1, 1977. Guidelines for preparation of power repayment studies are included in DOE Order No. RA 6120.2, Power Marketing Administration Financial Reporting. Procedures for Public Participation in Power and Transmission Rate Adjustments of the Power Marketing Administrations are found at Title 10, part 903, subpart A of the Code of Federal Regulations (10 CFR 903).

Southwestern markets power from 24 multi-purpose reservoir projects, with hydroelectric power facilities constructed and operated by the U.S. Army Corps of Engineers. These projects are located in the states of Arkansas, Missouri, Oklahoma, and Texas. Southwestern's marketing area includes these States plus Kansas and Louisiana. The costs associated with the hydropower facilities of 22 of the 24 projects are repaid via revenues received under the Integrated System rates, as are Southwestern's transmission facilities that consist of 1,380 miles of high-voltage transmission lines, 24 substations, and 46 microwave and VHF radio sites. Costs associated with the Robert D. Willis and Sam Rayburn Dams, two projects that are isolated hydraulically, electrically, and financially from the Integrated System are repaid by separate rate schedules.

Following Department of Energy guidelines, the Administrator, Southwestern, prepared a Current Power Repayment study using the existing Robert D. Willis rate. The Study indicates that Southwestern's legal requirement to repay the investment in the power generating facilitiy for power and energy marketed by Southwestern will be under-collected without an increase in revenues. The need for increased revenues is primarily due to increased costs for Corps of Engineers' operations and maintenance expenses. The Revised Power Repayment Study shows that an increase in annual revenue of $123,912 (a 35.0 percent increase), beginning October 1, 2003, is needed to satisfy repayment criteria.

Opportunity is presented for Southwestern customers and other interested parties to receive copies of the Robert D. Willis Power Repayment Studies and the proposed rate schedule. If you desire a copy of the Robert D. Willis Power Repayment Data Package with the proposed Rate Schedule, submit your request to Mr. Forrest E. Reeves, Assistant Administrator, Office of Corporate Operations, Southwestern Power Administration, One West Third Street, Tulsa, OK 74103, (918) 595–6696 or via email to *gene.reeves@swpa.gov.*

A Public Information Forum is scheduled to be held on July 15, 2003, to explain to customers and the public the proposed rate and supporting studies. The Forum will be conducted by a chairman who will be responsible for orderly procedure. Questions concerning the rate, studies, and information presented at the Forum will be answered, to the extent possible, at the Forum. Questions not answered at the Forum will be answered in writing, except that questions involving voluminous data contained in Southwestern's records may best be answered by consultation and review of pertinent records at Southwestern's offices.

Persons interested in attending the Public Information Forum should indicate in writing by letter or facsimile transmission (918–595–6656) by July 8, 2003, their intent to appear at such Forum. If no one so indicates their intent to attend, no such Forum will be held.

A Public Comment Forum is scheduled to be held on July 31, 2003, at which interested persons may submit written comments or make oral presentations of their views and comments related to the rate proposal. The Forum will be conducted by a chairman who will be responsible for orderly procedure. Southwestern's representatives will be present, and they and the chairman may ask questions of the speakers.

Persons interested in attending the Public Comment Forum should indicate in writing by letter or facsimile transmission (918–595–6656) by July 25, 2003, their intent to appear at such Forum. If no one so indicates their intent to attend, no such Forum will be held. Persons interested in speaking at the Forum should submit a request to the Administrator, Southwestern, in writing by July 25, 2003, their intent to appear at such Forum, so that a list of speakers can be developed. The chairman may allow others to speak if time permits.

A transcript of each Forum will be made. Copies of the transcripts may be obtained directly from the transcribing service for a fee.

Written comments on the proposed Robert D. Willis Rate are due on or before August 25, 2003. Five copies of the written comments, together with a diskette in MS Word or Corel Word Perfect, should be submitted to the Administrator, Southwestern, at the above-mentioned address for Southwestern's offices.

Following review of the oral and written comments and the information gathered during the course of the proceedings, the Administrator will submit the amended Robert D. Willis Rate Proposal, and Power Repayment Studies in support of the proposed rate to the Secretary of Energy for confirmation and approval on an interim basis, and subsequently to the Federal Energy Regulatory Commission (FERC) for confirmation and approval on a final basis. The FERC will allow the public an opportunity to provide written comments on the proposed rate increase before making a final decision.

Dated: June 13, 2003.

Michael A. Deihl,

Administrator.

[FR Doc. 03–15887 Filed 6–23–03; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Operational Alternatives for Post–2004 Operations

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of intent.

SUMMARY: The Western Area Power Administration (Western), is a Federal power marketing administration within the Department of Energy (DOE) and markets Federal power from the Central Valley and Washoe Projects through the Sierra Nevada Region (SNR). SNR is implementing a new Marketing Plan on January 1, 2005. On December 31, 2004, three existing long-term contracts with the Pacific Gas and Electric Company (PG&E) expire. To cost effectively implement its new Marketing Plan, SNR identified a number of alternative post-2004 operating scenarios. Western must select and implement one of these alternatives in a timely manner so that customers of SNR will avoid substantial business risk and uncertainty and not be subject to increased costs.

DATES: Written comments from entities interested in commenting must be received no later than 4 p.m., PDT, August 8, 2003. Western will accept written comments received via regular mail through the U.S. Postal Service if they are postmarked at least 3 days before August 8, 2003, and received no later than August 13, 2003. Entities are encouraged to hand deliver or use certified or electronic mail for delivery of comments. Western will not consider comments received after the prescribed date and time. SNR will hold a Public Information Forum to describe the alternatives under consideration on July 9, 2003, Folsom, CA, beginning at 10 a.m. SNR will also hold a Public Comment Forum on July 30, 2003, Folsom, California, at 10 a.m.

ADDRESSES: The Public Information Forum and Public Comment Forum will be held at the Lake Natoma Inn, 702 Gold Lake Drive, Folsom, California. Written comments should be sent to Tom Carter, Power Operations Manager, Western Area Power Administration, Sierra Nevada Customer Service Region, 114 Parkshore Drive, Folsom, CA 95630–4710, or by electronic mail to *TCarter@wapa.gov*.

FOR FURTHER INFORMATION CONTACT: Tom Carter, Power Operations Manager, (916) 353–4427, or by electronic mail at *TCarter@wapa.gov*.

SUPPLEMENTARY INFORMATION:

Authorities

The Marketing Plan for marketing power by the SNR after 2004, published in the **Federal Register** (64 FR 34417) on June 25, 1999, was established pursuant to the Department of Energy Organization Act (42 U.S.C. 7101–7352); the Reclamation Act of June 17, 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 specifically applicable to the projects involved.

Background

Western is a Federal power marketing administration within DOE and published its 2004 Power Marketing Plan (Marketing Plan) for SNR in the **Federal Register** (64 FR 34417) on June 25, 1999. The Marketing Plan specifies the terms and conditions under which Western will market Federal power from the Central Valley Project (CVP), the Washoe Project, and any additional power purchased to supplement Federal hydropower generation beginning January 1, 2005. SNR has three long-term contracts (Contracts 14–06–200–2947A (2947A), 14–06–200–2948A (2948A), and 14–06–200–2949A (2949A)) with PG&E expiring on December 31, 2004. The Southern California Edison Company (SCE) and the San Diego Gas and Electric Company (SDG&E) are also parties to Contract 2947A. The three contracts provide for the integrated and interdependent operation of the Federal and PG&E transmission systems. PG&E provides transmission services to SNR's customers and Project Use loads on the PG&E system, interconnects the section of the Pacific AC Intertie (PACI) line owned by Western with PG&E-owned facilities, and provides Western with 400 megawatts (MW) of transmission capacity rights to and from the Pacific Northwest.

Under legislation authorizing the construction of the Federal CVP, the Federal Government had originally planned to construct Federal generation and transmission facilities to serve specific Project Use facilities and Preference Power allottees. PG&E proposed an alternative solution, which integrated the transmission and generation resources of both organizations. PG&E stated that its approach would be more economic and would be less costly than if the Federal Government undertook construction. This synergistic approach became the basis of the relationship between Western and PG&E for more than 50 years. In 1967, Western and PG&E executed Contracts 2947A, 2948A, and 2949A. Contract 2947A provides Western up to 400 MW of priority transmission capacity on the PACI transmission system. Under Contract 2948A, PG&E integrates the hydro-generation resources of the CVP and Western's purchased energy with its resource portfolio to meet the combined PG&E and SNR loads. Under this arrangement, PG&E provides firming energy, as needed, to support the Project Use loads and SNR's power allocations. Contract 2949A interconnects PG&E's transmission system with Western's at PG&E's Round Mountain Substation.

As part of PG&E's overall operational responsibilities under Contract 2948A, PG&E provides control area services to support SNR's loads. When California restructured its electric utility industry in 1996 with the passage of Assembly Bill 1890, the California Independent System Operator (CAISO) was created and took over operational control of the transmission lines of the three investor-owned utilities (PG&E, SCE, and SDG&E). The CAISO also assumed control area operator responsibilities for the geographic service territory of the three investor-owned utilities. Under existing arrangements, PG&E secures control area services from the CAISO to meet PG&E's contractual obligations for Contract 2948A deliveries.

PG&E has indicated that after the contracts expire, it will no longer provide the services identified in these contracts under the same terms and conditions in support of SNR's power marketing program. When these three long-term contracts expire on December 31, 2004, PG&E has informed Western that SNR must either obtain or self-provide many of the control area services currently provided by Contract 2948A for Project Use loads and its customers directly connected to the Federal transmission system. In addition, SNR will need to initiate new scheduling arrangements for Project Use loads, CVP generation, and customer allocations served through, or attached to, the CAISO controlled-grid. To ensure non-interrupted cost-effective deliveries of Federal power, Western is preparing to assume responsibility for providing many of these services.

Beginning January 1, 2005, SNR is assuming that it has the responsibility for providing many of the services currently provided by PG&E under existing contracts for the delivery of Federal power to Project Use loads on both the Federal and PG&E transmission systems. Nothing in this notice should be taken as a waiver of Western's rights or ability to take other actions to secure service.

To maintain operational flexibility for the CVP and the Washoe Project, as well as to implement the Marketing Plan in a cost-effective manner in the post-2004 environment, SNR is considering several alternative operating scenarios. One of the alternatives identified by SNR is the option of forming a new control area. Other alternatives include becoming a CAISO Participating Transmission Owner (TO) or operating within the CAISO control area as a sub-control area in a manner similar to a Metered Sub-System (MSS). The purpose of this notice is to advise interested stakeholders of SNR's potential activities and to solicit comments on the alternatives.

The Marketing Plan describes how SNR will market CVP, the Washoe Project, and purchased power resources during the period January 1, 2005, through December 31, 2024. CVP power facilities include 11 powerplants with a maximum operating capacity of about 2,044 MW and an estimated average annual generation of 4.6 million megawatt hours (MWh). The Washoe Project's Stampede Powerplant has a maximum operating capacity of 3.65 MW with an estimated annual generation of 10,000 MWh. The Sierra Pacific Power Company owns and operates the only transmission system available for access to the Stampede Powerplant.

Each of the alternatives under consideration will expose SNR and its customers to a different set of financial and operational risks and will require the development of different operating protocols and procedures.

Depending upon the alternative selected, Western may be required to purchase, acquire, or construct additional facilities to establish the electrical boundaries of its system and provide a contiguous path between facilities owned by Western. For instance, Western owns the 94-circuit-mile Malin-Round Mountain 500-kilovolt (kV) transmission line (an integral section of the Pacific Northwest-Pacific Southwest Intertie) but does not own the electrical facilities that interconnect this line to Round Mountain Substation. Western also does not own the transformation facilities between the 500-kV and 230-kV transmission lines at Round Mountain Substation or the interconnection facilities for the 230-kV transmission lines at the Cottonwood Substation. Interconnection facilities for a number of Western-owned transmission lines at the Cottonwood Substation are also not owned by Western. The scope of the acquisition or construction of new facilities will be determined in large part by the point at which SNR defines its control area or sub-control area boundaries.

Description of Alternatives

SNR has identified the following alternative post-2004 operating scenarios:

1. The no-action alternative;
2. Executing a Transmission Control Agreement (TCA) and becoming a CAISO Participating TO;
3. Executing a sub-control agreement with CAISO similar to its MSS concept; or
4. Forming a Western Electricity Coordinating Council (WECC)/North American Electric Reliability Council (NERC) certified control area with the U.S. Department of the Interior, Bureau of Reclamation (Reclamation) generation and load, and certain other generation and load within the proposed control area boundary.

Factors To Be Considered During Decision-Making

In making a decision as to which post-2004 operational scenario to implement, SNR has identified factors that it will use in its decision-making process. These factors include, but are not limited to:

1. *Flexibility:* Preserves the ability of SNR to join a Federal Energy Regulatory Commission (FERC) approved and certified Regional Transmission Organization (RTO) in the future and to implement other industry changes;
2. *Certainty:* Assures that cost-of-service rates are stable and predictable;
3. *Durability:* Operating protocols are well established and subject to minimal changes over time;
4. *Operating Transparency:* Minimizes operating impacts to third parties;
5. *Cost-Effectiveness:* Cost shifts are minimized and relative cost-benefit ratios to SNR's customers will be considered.

FERC is actively encouraging the formation of RTOs. An RTO is an independent transmission system operator, governed by an independent board of directors. The RTO is responsible for operating a geographically discrete and interconnected regional transmission system consistent with prudent utility practices as defined by NERC and WECC. The selected alternative must have sufficient flexibility to allow SNR to accommodate the possibility of joining an RTO as well as modifying its operations to implement other changes in the electric utility industry. Although Western is not required to undertake a formal public process to select an operating configuration for post-2004 operations, Western has determined that it serves the public interest to allow interested stakeholders an opportunity to provide comments as Western goes through its decision-making process. In arriving at its final decision, SNR will accept and evaluate all comments received from interested stakeholders and ensure that its decision-making process is consistent with all applicable Federal laws, regulations, and procedures.

No-Action Alternative

If this alternative is selected, SNR and Reclamation would not execute successor transmission arrangements with PG&E or the CAISO. Since a basis for transactions or business relationships necessary to carry out deliveries of power to customers does not exist, substantial business uncertainty would result. One or more of the parties could pursue litigation to determine the respective positions of Western and its individual customers, Reclamation, CAISO, and PG&E. This alternative creates business uncertainty and operational impediments which would result from not having successor agreements in place with PG&E and the CAISO.

CAISO Participating Transmission Owner

Under this alternative, SNR, at a minimum, would need to execute a TCA, thus transferring operational control of the Federal transmission system to the CAISO. SNR would, however, retain responsibility for continuing to maintain all of its transmission facilities. Execution of the TCA would obligate SNR to conform its maintenance, operations, business, and administrative practices to all applicable CAISO protocols and procedures provided they do not conflict with existing Federal law.

Transmission revenue requirements associated with annual maintenance and capital repayment obligations for the Federal transmission system on behalf of SNR would be recovered through the CAISO Transmission Access Charge (TAC). In lieu of utility-specific cost-of-service rates, Federal transmission system beneficiaries would transition to a statewide rate, which represents the melded cost of all statewide Participating TO transmission revenue requirements.

To participate in the CAISO markets, and as the owner of the Federal generation assets, Reclamation would have to execute a Participating Generator Agreement (PGA). Execution of the PGA would allow the CVP to contribute energy and/or ancillary services in excess of SNR's existing contractual obligations into the market, if available.

Scheduling power across the Federal system would be done by the CAISO under terms governed by the CAISO tariffs. These tariffs are intended to afford equal opportunity use of all the existing transmission under CAISO control to all market participants. Under the existing CAISO Tariff, transmission of CVP generation to Project Use loads and SNR's customers will not be afforded any preference. In addition, if transmission is constrained; *e.g.*, inter-zonal or intra-zonal congestion exists, non-Federal generation may be re-dispatched to cover loads. As the anticipated Scheduling Coordinator (SC) for Reclamation's Project-Use loads and resources, SNR would pay the market clearing price for any power deliveries associated with energy imbalance costs. Under this scenario, assuming that SNR is the SC for both CVP generation and Project-Use loads, power would be scheduled from CVP generation to its customers and any excess generation, if available, would be bid as reserve (unloaded) capacity into the CAISO markets. Any imbalances caused by load deviations would be paid for by the SC for Project Use loads and SNR's customers. All revenues from sales to the CAISO markets would be applied to meet the repayment requirements of the CVP. The revenue requirement for CVP transmission will be collected by the CAISO under terms of the TCA.

From an operational perspective, CVP generation would be scheduled into the CAISO control area and the CAISO-controlled grid, including Federal transmission assets, would be used to deliver Federal power and/or purchases to Project Use loads and SNR's customers. Under this alternative, the costs associated with energy deliveries to Project Use loads and SNR's customers are subject to the hourly CAISO market prices, transmission congestion charges, imbalance energy charges, and all other charges that the CAISO imposes to cover its costs or to collect revenue it must collect for transmission owners. Whenever actual load requirements exceed the scheduled amounts, the energy would be provided by the CAISO under its energy imbalance program.

From an organizational perspective, this alternative appears to be the easiest to implement. SNR would not need a real-time transmission scheduling or an automatic generation control (AGC) desk; however, to retain its status as an SC, a 24-hour merchant desk would still need to be established. A real-time transmission switching desk to monitor the Federal system, perform outage coordination and switching for maintenance activities, and coordinate system restoration activities would be needed. SNR would also have to maintain a settlements organization to account for and bill various charges associated with purchases and deliveries for customers for which SNR is designated as the SC and to reconcile and account for revenues associated with generation sales into the CAISO markets.

The impact of implementing this alternative would effectively increase the cost of transmission to all SNR customers. The differential would be most pronounced for those entities directly connected to the Federal transmission system. Integrating the Federal transmission system into the CAISO-controlled grid would result in an integrated TAC. However, since many of the direct-connected transmission users' transactions do not involve the use of the CAISO-controlled grid, direct-connected customers could end up paying for service that they would not necessarily need under other alternatives. Non-direct-connected customers would pay the non-discriminatory rate associated with the use of the CAISO-controlled grid. The net effect is that the overall average cost of transmission service could decrease for the rest of the existing CAISO market participants.

Executing an MSS Agreement With the CAISO

In lieu of becoming a Participating TO, the CAISO has offered SNR the option of becoming an MSS. The CAISO defines an MSS as the system of a transmission owner bounded by CAISO-certified revenue quality meters at each interface point and generating units internal to that metered system. Under this alternative, SNR and Reclamation will need to define the physical boundaries of the MSS, ensure the appropriate revenue quality meters are present at each interface point and the generators, and ensure the appropriate communications and telemetry are in place. Since the MSS concept recognizes internal generation, Reclamation will not need to execute a PGA. To minimize the cost of receiving services from the CAISO markets, SNR will need to balance its energy and ancillary services obligations on a continuous basis. This function will require a 24-hour per day balancing authority or an AGC desk. To minimize costs associated with deviations between actual loads and resources, a 24-hour merchant desk is required. To become an MSS, SNR would need to negotiate and execute an MSS agreement with the CAISO.

The MSS and the control area alternatives are very similar from an operational perspective. Both a control area and an MSS must define their boundaries at interconnections with others and both must have the ability to use the physical electrical path across these boundaries. The proposed transmission system boundaries for both the control area and the MSS can be viewed at the following Web site location: *http://www.wapa.gov/sn/P04/PDF/SNR-Boundary-06–02–03.PDF*

The northern boundary for the MSS alternative could change. Under the MSS alternative, Western would propose to put its Malin-Round Mountain transmission line in the CAISO control area and put its northern boundary at the 230-kV at the Round Mountain Substation on the Round Mountain-Cottonwood transmission line. Transmission scheduling between Malin and Round Mountain under the MSS alternative could be done by the CAISO while scheduling of transmission between Captain Jack and Tracy could be done by SNR. Western would still retain its existing capacity rights under a successor arrangement. The CAISO would remain the path operator for Path 66, the interface between the California-Oregon Border and Northern California, with the ability to curtail schedules on these paths if reliability is jeopardized.

An MSS is responsible for matching its internal loads and exports with generation and imports on an interval defined in the MSS agreement with the CAISO (not necessarily second-by-second). The MSS must maintain reserves in an amount that the MSS load bears to the entire load of the CAISO control area as defined in the MSS Agreement with the CAISO multiplied by the CAISO control area largest hazard (not necessarily the MSS largest hazard). The MSS does not have any responsibility to maintain the frequency of interconnection. This responsibility rests with the CAISO as the control area operator. The technical requirements for MSS performance are defined by the MSS Agreement with the CAISO. These requirements may change due to the CAISO Tariff revisions.

The CAISO's April 8, 2003, MSS proposal to SNR included the following key principles:

1. The MSS methodology would model SNR's service territory to include the entities directly connected to its transmission system unless these entities did not want to be included for scheduling and settlement purposes. The California-Oregon Transmission Project (COTP) line would also be included in SNR's MSS. An accommodation would have to be made for CAISO's share of COTP capacity rights currently owned by PG&E.

2. The CAISO would provide ''Net'' Settlements treatment for various CAISO market charges, as appropriate, based on cost causation principles.

3. No PG&E Unaccounted-for Energy (UFE) charge would be applied to load within SNR's territory.

4. SNR has the option of choosing to follow MSS load with MSS generation to minimize uninstructed energy deviation costs. Penalties would apply to all uninstructed deviations. The CAISO has also suggested that SNR could include entities not directly connected to its transmission system within the MSS and follow those loads with CVP generation.

5. SNR and Reclamation would have the ability to schedule customized combinations of MSS resources on a System Unit basis (aggregating resources for scheduling and settlements) to provide Reclamation with flexibility in dispatching individual generating resources.

6. Reclamation would not have to file a PGA, and Reclamation and SNR would have full access to all CAISO markets and associated services.

7. SNR would have the option of using multiple individual scheduling identifiers, as required, to facilitate and simplify CAISO settlements for SNR SC customers located on the CAISO grid but which are external to, and scheduled separately from, the Western MSS.

8. Ancillary services obligations would be based on a load ratio share of the CAISO ancillary services requirement.

9. Control area services would be provided by the CAISO.

Under the CAISO MSS proposal, SNR would, in essence, be a sub-control area operating within the CAISO control area with the AGC system operating in the flat tie-line mode. This means that the AGC algorithms would not contain a component to assist in the frequency support of the interconnection. SNR would regulate generation internal to the MSS so that the net actual interchange (net power flows to the CAISO and interconnected control areas) matches the net scheduled interchange.

From a transmission scheduling perspective, the MSS option requires SNR to schedule deliveries across the COTP line but not the Malin-Round Mountain line. Currently, these schedules are done between the CAISO and the Bonneville Power Administration (BPA). Implementation of the MSS option, including scheduling the use of transmission from the Pacific Northwest, will require coordination between SNR, CAISO, and BPA.

Forming a New Control Area

A control area is a specifically defined geographic region where responsibility for continuously matching generation and load is in accordance with NERC and WECC planning and operating criteria. A control area operator is responsible for continuously monitoring and balancing its resources against its load obligations and providing frequency support to the interconnected system. The control area operator must meet scheduled interchange requirements with other control areas, assist in maintaining the frequency of the electric power system, and provide sufficient generating capacity to maintain operating reserves. The control area operator must also ensure that it operates its transmission system in concert with other transmission providers in the area to maintain the reliability of the interconnected electric system.

Under this alternative, SNR would establish boundary and interface points with neighboring control areas; *e.g.*, BPA, CAISO, the Sacramento Municipal Utility District, and others, and install the appropriate metering and communication telemetry systems. In addition to the 24-hour merchant desk and the AGC desk identified under the MSS option previously, a transmission scheduling and security desk is also needed. Implementation of this option requires negotiating and executing additional agreements with the reliability coordinator, as well as inter-control area agreements with neighboring entities and intra-control area agreements with proposed control area participants. In the event that significant changes occur to the operation of the three-line California-Oregon Interconnect (COI) system, it may also be necessary to negotiate modifications to the COI's Coordinated Operations Agreement.

A control area is responsible for matching its internal load and exports with generation and imports on a second-by-second basis, for maintaining adequate reserves to cover its largest hazard, and to assist in maintaining the frequency of the interconnection. The technical requirements of the control area are contained in various NERC and WECC guidelines and standards; as such, these guidelines and standards may change due to industry consensus.

The control area alternative requires SNR to apply to NERC and WECC to become a certified control area. This requires SNR to demonstrate that it can meet all of the NERC and WECC planning and operational standards and requirements. The control area alternative has, as key principles, the following:

1. The proposed transmission system boundaries for the control area are shown at: *http://www.wapa.gov/sn/P04/PDF/SNR-Boundary-06–02–03.PDF* and initially will include those entities directly connected to the Federal transmission system. These loads include the cities of Redding, Roseville, and Shasta Lake; the Lawrence Livermore National Laboratory; Reclamation's Tracy Pumping Plants; the Sutter Energy Center; the East Contra Costa Irrigation District; and the Contra Costa Water District. The Malin-Round Mountain line and the COTP line would also be included in the proposed control area. All CVP hydro-generation directly connected to the Federal transmission system will be located within the control area.

2. Customers located within the control area will receive their allocation through internal control area schedules and will not experience any of the CAISO charges associated with those deliveries. Customers located on the CAISO grid will be assessed charges for delivery of their allocations associated with the use of the CAISO-controlled grid, ancillary services charges, transmission distribution charges, and other CAISO charges.

3. No PG&E UFE charges will apply to deliveries of Federal power to entities within the control area.

4. SNR will only follow the load for entities located within the control area. After becoming more experienced with control area operations, SNR will dynamically schedule generation through the CAISO system for interested entities to provide load following for customers that are not directly connected. This will minimize the CAISO imbalance energy charges for the off-system customers. Entities for which SNR provides load following services should not experience significant imbalance energy charges from the CAISO. These entities will, however, be charged for load following services.

5. Reclamation will have the flexibility to move water releases around their system as needed and will provide the generation levels scheduled for delivery internal to the control area and to the CAISO control area based on preschedules. There will be no uninstructed deviation charges associated with the control area alternative.

6. SNR expects to be the SC for Reclamation generation and for the loads of some of its customers and, therefore, would still participate in the CAISO markets under the control area alternative.

7. Schedules to customers located within the CAISO control area will be performed as SC-to-SC trades no differently than many of the deliveries of Federal power are made today.

8. SNR's reserve obligations will be shared by entities directly connected to the Federal transmission system in proportion to the load of each of these entities within the control area. This is the same approach (the load ratio share) as proposed by the CAISO in the MSS option. Regulation will be provided to the control area by CVP generation with the energy to be returned by those receiving such services.

9. All of the control area services outlined by the CAISO in the MSS alternative proposal will be provided by SNR under the control area alternative to entities within the control area.

SNR would regulate internal generation so that the net actual interchange matches the net scheduled interchange. Under the control area alternative, scheduling over the Malin-Round Mountain and the Captain Jack-Tracy paths would be done by SNR. SNR would begin load following for its internal customers when control area operations begin (January 1, 2005), and would request dynamic scheduling capability for off-system customers through the CAISO approximately 6 months later.

Transmission scheduling for deliveries across the COTP line and for the Malin-Round Mountain transmission line would continue to be coordinated between CAISO and BPA. Western recommends that under this alternative, the CAISO continue as the path operator for the COI, with full visibility for all the schedules and the ability to curtail schedules if reliability is threatened.

Other Considerations

In determining which alternative to implement, a major consideration for SNR and its customers is the cost of each alternative. Under the Participating TO alternative, customers would be subject to CAISO charges associated with deliveries of Federal power. Under the MSS alternative, certain CAISO charges would be avoided if a customer is included in the MSS. Under the control area alternative, certain CAISO charges would be avoided by customers within the control area and possibly imbalance charges can be avoided through the use of dynamic scheduling for off-system customers. The costs and benefits of each option are being assessed through a study being performed by a consultant for Reclamation. The results of this study are expected to be available by the time the Public Information Forum announced in this notice is held.

Implementing the MSS alternative would result in different cost-of-service rates for transmission service for entities directly connected to the Federal transmission system and those entities served from the CAISO-controlled grid. In some instances, the expected increase in costs, especially for Federal end use loads served on the CAISO-controlled grid, could be substantial. Since the CAISO levies charges based on the net load in its MSS option, there may be certain opportunities to use Federal hydropower resources of the CVP to meet load requirements of the MSS participants and, thus, mitigate any cost increases associated with the use of the CAISO-controlled grid. From the standpoint of the CAISO, implementation of this option would keep most of its existing operating procedures intact and would ensure that its costs are recovered from CVP users.

If the control area formation option is selected, there still could be impacts to others even though mitigation efforts are undertaken. Scheduling and operational complexity associated with management of the three-line COI system could result. SNR recommends that the CAISO continue to serve as the single Path Operator for the COI for operational continuity and to assure that impacts are minimized to the maximum extent possible.

Under the control area formation proposal, differential transmission rates could still accrue between customers directly connected to the Federal transmission system and those who are served by the CAISO-controlled grid. If cost-of-service rates to CAISO-controlled grid users are mitigated, this would result in cost shifts to others. Cost shifts could result to other users connected directly to the Federal transmission system or to entities seeking transmission service either on or through Western's transmission system to the CAISO-controlled grid. Finally, to the extent that a new control area is formed, fixed expenses associated with operation of the CAISO would have to be recovered from a smaller base and, consequently, average unit costs for the remaining participants in the CAISO could increase.

Representatives from SNR will describe the above alternatives and the results of the cost/benefit study at the Public Information Forum. Western will accept public comments on the alternatives presented at the Public Comment Forum. SNR will accept additional written comments until the end of the comment period.

Consistency with Federal Law

Western will evaluate how Federal law will impact each of the alternatives. Western is governed by numerous Federal laws such as the Federal Reclamation Law. The Federal Reclamation Law requires the sale of Federal power be sold to Preference customers. Western implements such sales through a Federal marketing plan under the Administrative Procedure Act. The sale of Federal power must not impair the primary purposes of the CVP. The marketing plans have the full force and effect of law. The alternatives must be consistent with Western's obligations under Federal law including Western's Marketing Plan. For instance, if Western were to become a Participating TO, it is conceivable that situations could arise where Western would be unable to deliver Federal Preference Power to Federal customers even where adequate Federal transmission capability was available to serve the Federal customer. While the CAISO Tariff provides a waiver for Federal entities if a provision of the Tariff conflicts with the Federal law, Western must still work out the specific details on a case-by-case basis whenever such conflicts arise.

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 services applicable to public property.

Environmental Compliance

Under the National Environmental Policy Act (NEPA) (42 U.S.C. 4321, *et seq.*), Council on Environmental Quality NEPA implementing regulations (40 CFR part 1500–1508), and DOE NEPA implementing regulations (10 CFR part 1021), Western completed an environmental impact statement (EIS) on its Energy Planning and Management Program. The Record of Decision was published in the **Federal Register** (60 FR 53181, October 12, 1995).

Western also completed the 2004 Power Marketing Program EIS (2004 EIS), and the Record of Decision was published in the **Federal Register** (62 FR 22934, April 28, 1997). The Marketing Plan falls within the range of alternatives considered in the 2004 EIS. This NEPA review identified and analyzed environmental effects related to the Marketing Plan. Available reservoir storage and water releases controlled by Reclamation influence marketable CVP and Washoe Project electrical capacity and energy. Reclamation completed a programmatic Environmental Impact Statement (PEIS) under the CVP Improvement Act of 1992 (Pub. L. 102–575, Title 34) on October 1999. Actions based on the PEIS may result in modifications to CVP facilities and operations that would affect timing and quantity of electric power generated by the CVP. Such changes may affect electric power products and services marketed by SNR. The Marketing Plan has the flexibility to accommodate these changes. Western was a cooperating agency in Reclamation's PEIS process.

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 services and involves matters of procedure.

Dated: June 12, 2003.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 03–15885 Filed 6–23–03; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7518–3]

Availability of ''Supplemental Allocation of Fiscal Year 2003 Operator Training Grants for Wastewater Security''

AGENCY: Environmental Protection Agency.

ACTION: Notice of document availability.

SUMMARY: EPA is announcing the availability of a guidance memorandum entitled ''Supplemental Allocation of Fiscal Year 2003 Operator Training Grants.'' This memorandum provides national guidance for the allocation of funds used under section 104(g)(l) of the Clean Water Act. By providing additional funding to the 104(g) environmental training centers throughout the United States, the program will provide on-site security assistance and classroom training security activities to operators at small community wastewater treatment facilities in order to help the facility to become more secure.

ADDRESSES: United States Environmental Protection Agency, EPA East, Municipal Assistance Branch, 1200 Pennsylvania Avenue, NW., (Mail Code 4204–M), Washington, DC 20460.

FOR FURTHER INFORMATION CONTACT: Curt Baranowski at (202) 564–0636, or email: *baranowski.curt@epa.gov*.

SUPPLEMENTARY INFORMATION: The subject memorandum may be viewed and downloaded from EPA's homepage, *www.epa.gov/owm/tomm.htm*, under ''*Supplemental Wastewater Security Grant Guidance*.''

Dated: June 18, 2003.

Peter E. Shanaghan,

Acting Director, Office of Ground Water and Drinking Water.

[FR Doc. 03–15903 Filed 6–23–03; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7517–7]

Notice of Meeting of the EPA's Children's Health Protection Advisory Committee (CHPAC)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meeting.

SUMMARY: Pursuant to the provisions of the Federal Advisory Committee Act, Public Law 92–463, notice is hereby given that the next meeting of the Children's Health Protection Advisory Committee (CHPAC) will be held July 15–17, 2003 at the Hotel Washington, Washington, DC. The CHPAC was created to advise the Environmental Protection Agency on science, regulations, and other issues relating to children's environmental health.

DATES: Tuesday, July 15 the Science/Regulatory Work Group will meet; plenary sessions will take place Wednesday, July 16 and Thursday, July 17.

ADDRESSES: Hotel Washington, 515 15th Street, NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Contact Joanne Rodman, Office of Children's Health Protection, USEPA, MC 1107A, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 564–2188, *rodman.joanne@epa.gov.*

SUPPLEMENTARY INFORMATION: The meetings of the CHPAC are open to the public. The Science/Regulatory Work Group will meet Tuesday, July 15 from 9 a.m. to 5 p.m. The plenary CHPAC will meet on Wednesday, July 16 from 9 a.m. to 5 p.m., with a public comment period at 4:45 p.m., and on Thursday, July 17 from 9 a.m. to 12 p.m.

The plenary session will open with introductions and a review of the agenda and objectives for the meeting. Agenda items include highlights of the Office of Children's Health Protection (OCHP) activities and reports from the Science and Regulatory Work Group. Other potential agenda items include strategic review of the progress on children's environmental health issues since the CHPAC was formed in 1997, and a panel presentation on the Voluntary Children's Chemical Evaluation Program (VCCEP).

Dated: June 18, 2003.

Joanne K. Rodman,

Designated Federal Official.

[FR Doc. 03–15902 Filed 6–23–03; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7518–2]

Science Advisory Board; Notification of Public Advisory Committee Meeting; Executive Committee

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) Science Advisory Board (SAB) Executive Committee (EC), a Federal Advisory Committee, will hold a public meeting on the date and time given below to obtain briefings on EPA Regional science issues, and to discuss the SAB Operating Plan for FY2004.

DATES: The meeting will take place on Wednesday and Thursday, July 16–17, 2003 beginning 9 a.m. on July 16 and adjourning no later than 12 noon on July 17 (Central Time). Requests for oral comments, as well as submission of written comments must be received by July 8, 2003. Please see further details below.

ADDRESSES: The meeting will be held in the Lake Michigan Conference Room, U.S. EPA Region 5 Headquarters, Metcalfe Federal Building, 77 West Jackson Boulevard, Chicago, Illinois. For meeting location, building access, and visitor information, please see the Region 5 Web site at: *http://www.epa.gov/region5/visitor/index.htm.*

FOR FURTHER INFORMATION CONTACT: Any member of the public wishing further information concerning this meeting or wishing to present oral comments must contact Mr. A. Robert Flaak, Designated Federal Officer, EPA Science Advisory Board (1400A), U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone (202) 564–4546; Fax (202) 501–0582; or via e-mail at *flaak.robert@epa.gov.*

SUPPLEMENTARY INFORMATION: *Summary:* Pursuant to the Federal Advisory Committee Act, Public Law 92–463, notice is hereby given that the EC of the U.S. EPA Science Advisory Board (SAB) will hold a public meeting to discuss the following topics:

(a) *EPA Regional Science Issues*—The SAB will receive briefings from, and discuss scientific issues, with Regional senior leadership and scientists. These are designed to: (1) inform the SAB about regional science issues and concerns; (2) identify opportunities for future SAB and Regional office interactions on topics of interest; and (3) provide the regions with insights into the overall SAB role in advising the